2006 State of the Market Report

VOLUME II: DETAILED ANALYSIS

MARKET MONITORING UNIT
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PREFACE

The Market Monitoring Unit of PJM Interconnection publishes an annual state of the market report that assesses the state of competition in each market operated by PJM, identifies specific market issues and recommends potential enhancements to improve the competitiveness and efficiency of the markets.

The *2006 State of the Market Report* is the ninth such annual report. This report is submitted to the Board of PJM Interconnection pursuant to the PJM Open Access Transmission Tariff (OATT), Attachment M (PJM Market Monitoring Plan):

> The Market Monitoring Unit shall prepare and submit to the PJM Board and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Market. In such reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The reports to the PJM Board shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

The Market Monitoring Unit is submitting this report simultaneously to the United States Federal Energy Regulatory Commission per the Commission's order:

> The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of an RTO's [regional transmission organization's] market monitor at the same time they are submitted to the RTO.[2]

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

2 96 FERC ¶ 61,061 (2001).

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SECTION 1 – INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that in 2006 had average installed generating capacity of 162,571 megawatts (MW) and more than 450 market buyers, sellers and traders of electricity in a region including more than 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.[1] As part of that function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

PJM Market Background

PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Daily Capacity Market, the Interval, Monthly and Multimonthly Capacity Markets, the Regulation Market, the Synchronized Reserve Markets and the Annual and monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets in mid-1999. PJM implemented an auction-based FTR Market on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003.[2]

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.[3]

Volume I of the *2006 State of the Market Report* is the Introduction. More detailed analysis and results are included in Volume II.

Conclusions

This report assesses the competitiveness of the markets managed by PJM during 2006, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of PJM's independent Market Monitoring Unit (MMU).

The MMU concludes that in 2006:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;
- The Regulation Market results cannot be determined to have been competitive or to have been noncompetitive;
- The Synchronized Reserve Markets' results were competitive; and
- The FTR Auction Market results were competitive.

1 See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

2 See also *2006 State of the Market Report*, Volume II, Appendix B, "PJM Market Milestones."

3 Definitions of these phases are included in the *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

Recommendations

The MMU recommends retention of key market rules, specific enhancements to those rules and implementation of new rules that are required for continued competitive results in PJM markets and for continued improvements in the functioning of PJM markets. The recommendations are for continued action where PJM has already identified areas for improvement and for new action in areas where PJM has not yet identified a plan.

Continued Action

- Retention and application of the improved local market power mitigation rules to prevent the exercise of local market power in the Energy Market while ensuring appropriate economic signals when investment is required.

  PJM introduced a new test for local market power in 2006, the three pivotal supplier test. 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. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. The application of the three pivotal supplier test successfully limited offer capping in the Energy Market to situations where the local market structure was noncompetitive and where specific owners had structural market power.

- Retention of the $1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power.

  The PJM market design includes a variety of rules that effectively limit the incentive to exercise market power and ensure competitive outcomes. These should be retained and every PJM market rule change should be evaluated for its impact on competitive outcomes.

- Implementation of the rules included in PJM's Reliability Pricing Model (RPM) Tariff to stimulate competition, to provide direct incentives for performance, to provide locational price signals, to provide forward auctions to permit competition from new entrants and to incorporate explicit market power mitigation rules.

  Market power remains a serious concern in the PJM Capacity Market based on market structure conditions in this market including high levels of supplier concentration, frequent occurrences of pivotal suppliers, extreme inelasticity of demand and lack of market power mitigation measures under the market design in place during 2006. The RPM capacity market design explicitly provides that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective and explicitly limiting the exercise of market power via the application of the three pivotal supplier test.

- Enhancements to PJM's rules governing operating reserve credits to generators to ensure that credits and corresponding charges to market participants are consistent with incentives for efficient market outcomes and to reduce gaming incentives.

  PJM and the MMU have been working with the Reserve Market Working Group to develop a set of market design modifications to implement these goals. The process should be completed and the modifications implemented.

- Continued enhancements to the cost-benefit analysis of congestion and transmission investments to relieve that congestion, especially where that congestion may enhance generator market power and where such investments support competition.

PJM has significantly improved its approach to the cost-benefit analysis of transmission investments. PJM should continue to evaluate critically its approach, particularly as it applies to constraints with large and persistent market impacts. Developing an approach to weighting and evaluating the multiple metrics in the context of actual transmission projects will require substantial effort. New transmission projects and the lack of existing transmission can have significant impacts on the PJM markets and the goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market-driven processes as much as is practicable.

- Continued enhancement of PJM's posting of market data to promote market transparency.

  PJM has expanded the types and extent of data posted to the Web for public access. PJM should continue to expand data posting consistent with the goal of improving transparency and stimulating competition.

- Provision of data for external control areas to PJM to enable improved analysis of loop flows in order to enhance the efficiency of PJM markets.

  PJM has only limited access to the data required for a complete analysis of loop flow in the Eastern Interconnection. Provision of such data access and completion of the loop flow analysis could significantly enhance the transparency and efficiency of energy markets in both market and non market areas and the efficiency of transactions between market and non market areas. Loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas.

- Evaluation of additional actions to increase demand-side responsiveness to price in both Energy and Capacity Markets and of actions to address institutional issues which may inhibit the evolution of demand-side price response.

  PJM and the MMU should continue to ensure that market power is not exercised on the demand side of the market. PJM has improved the design of the demand-side resource rules. The principal barriers to the further development of demand-side response are in the interface between wholesale and retail markets. PJM and the MMU should continue their efforts in that area.

- Based on the experience of the MMU during its eighth year and its analysis of the PJM markets, the MMU recognizes the need to continue to make the market monitoring function independent, well-organized, well-defined, clear to market participants and consistent with the policy of the FERC. The MMU recommends that the Market Monitoring Plan be further modified consistent with these objectives.[4]

New Action

- Enhancements to PJM's scarcity pricing rules to create stages of scarcity and corresponding stages of locational scarcity pricing in order to ensure competitive prices when scarcity conditions exist in market regions.

  The MMU reviewed the summer of 2006 for scarcity conditions and the market prices that resulted. Based on the results, the MMU suggests that PJM's scarcity pricing mechanism be reviewed and modified. The definition of scarcity should include several steps or states of scarcity, each with an associated price, rather

4 PJM, OATT, "Attachment M: PJM Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006). Section VII.A. states: "The reports to the PJM Board shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required."

than the single step now in the Tariff. Scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. In addition, the actual market signal needs further refinement. Under the current rules, a scarcity pricing event sets prices for all generators in the defined area at the same level, equal to the highest accepted offer within a scarcity pricing region. The single scarcity price signal should be replaced by locational signals.

- Implementation of targeted, flexible real-time market power mitigation in the Regulation Market.

  PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU concludes from the analysis of the 2006 data that the PJM Regulation Market in 2006 was characterized by structural market power in 26 percent of the hours, based on the results of the three pivotal supplier test.[5] The MMU also concludes that PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition compared to the PJM Mid-Atlantic Regulation Market or the Western Region Regulation Market on a stand-alone basis.[6] The MMU concludes that it would be preferable to retain the existing, experimental single PJM Regulation Market as the long-term market if appropriate mitigation can be implemented. Such mitigation, in the form of the three pivotal supplier test, addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition. While suppliers have not provided data on their cost to regulate, an analysis of the Regulation Market based on the MMU's cost estimates indicates that offers above the competitive level set the clearing prices in about 30 percent of the hours. The combined market results include the effects of the current mitigation mechanism which offer caps the two dominant suppliers in every hour. The MMU also recommends that all suppliers be required to provide cost-based regulation offers, consistent with the practice in the energy market.

- Consistent application of local market power rules to all constraints.

  The MMU recommends that the Commission 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. 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. For the identified exempt interfaces, this could have resulted in the 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 will be applied only as necessary and will be applied on a non-discriminatory basis for all units operating for all constraints.

5 This is the same conclusion reached in the MMU report on the first year of the Combined Regulation Market. See Market Monitoring Unit, "Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006" (October 18, 2006) <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20061018-mmu-regulation-market-report.pdf> (76.1 KB).

6 *2005 State of the Market Report* (March 8, 2006), pp. 260-263.

- Consideration by the FERC of ending 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 section 206 of the Federal Power Act and that the just and reasonable practice under section 206 is to terminate the exemption, with provisions to grandfather units for which construction commenced in reliance on the exemption."[7] The FERC noted, however, that grandfathered units would "still be subject to mitigation in the event that PJM or its market monitor concludes that these units exercise significant market power."[8] 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 PJM prices in 2006.

7 110 FERC ¶ 61,053 (2005).

8 110 FERC ¶ 61,053 (2005).

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).

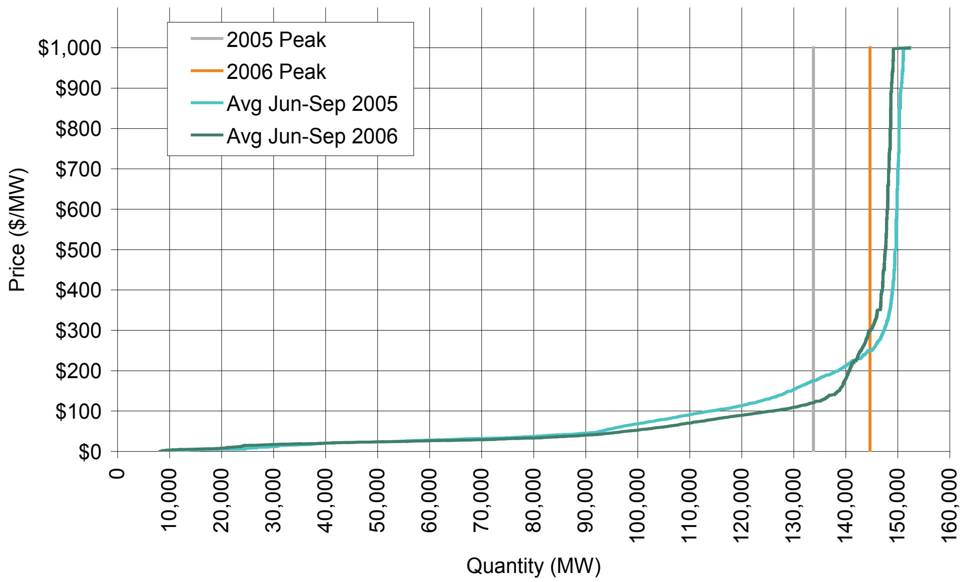
6 110 FERC ¶ 61,053 (2005).

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

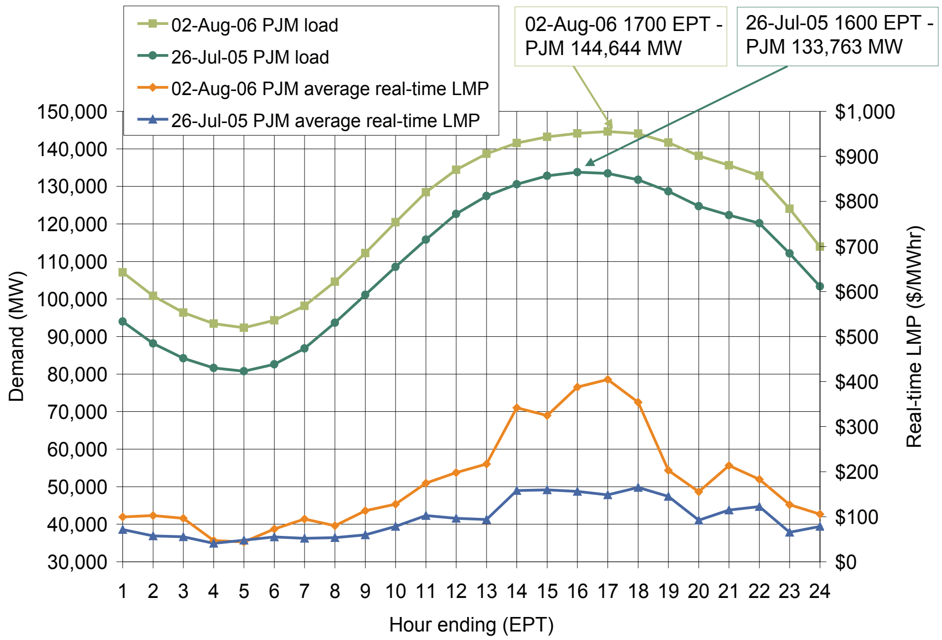
11 Retired unit parameters obtained from PJM.

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%

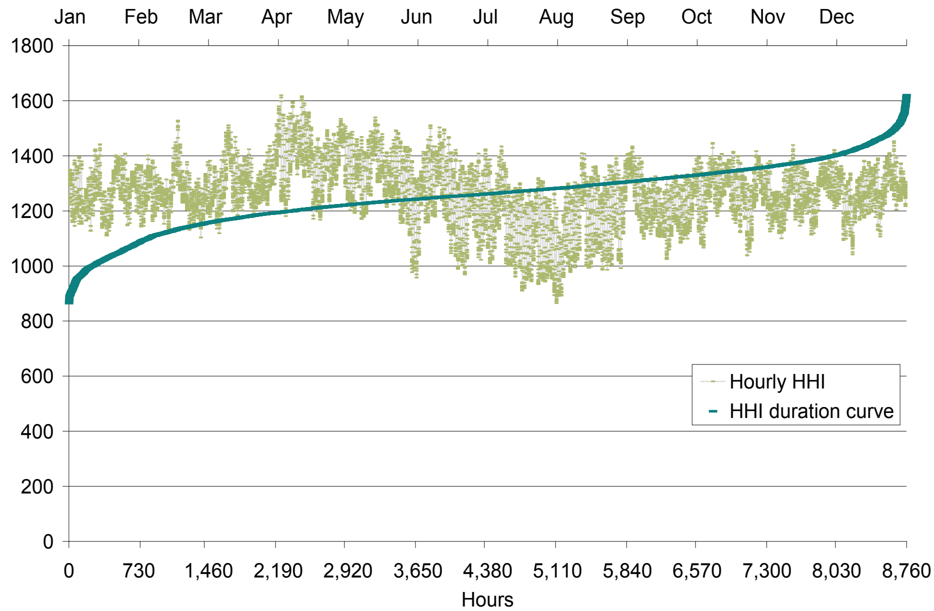
Table 2-4 includes 2006 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

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.”

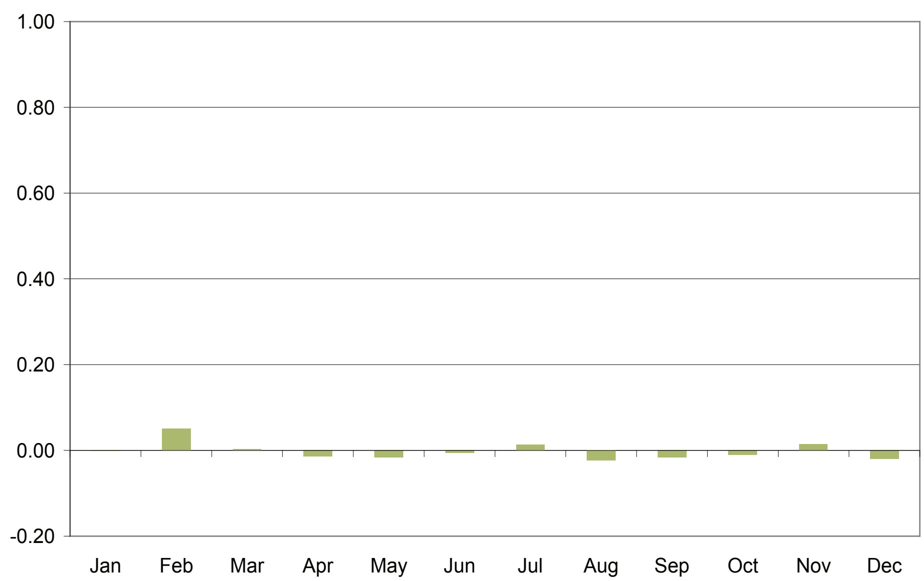
Market Conduct

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.

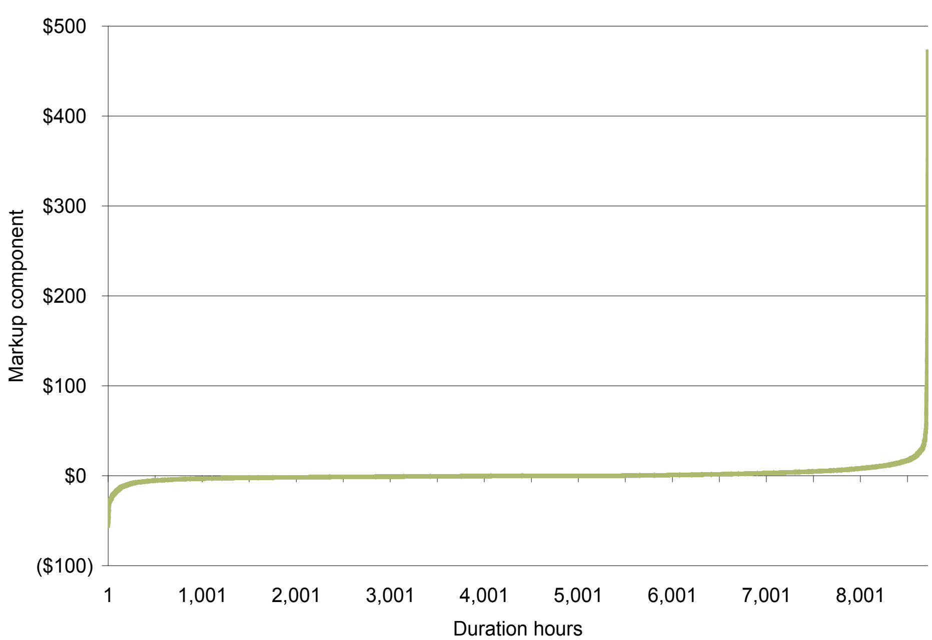
31 For a definition of high-load days, see *2006 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," at "High-Load Events, Scarcity and Scarcity Pricing Events." For the analysis of components of LMP, seven high load days are included when high load days are referenced. The seven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

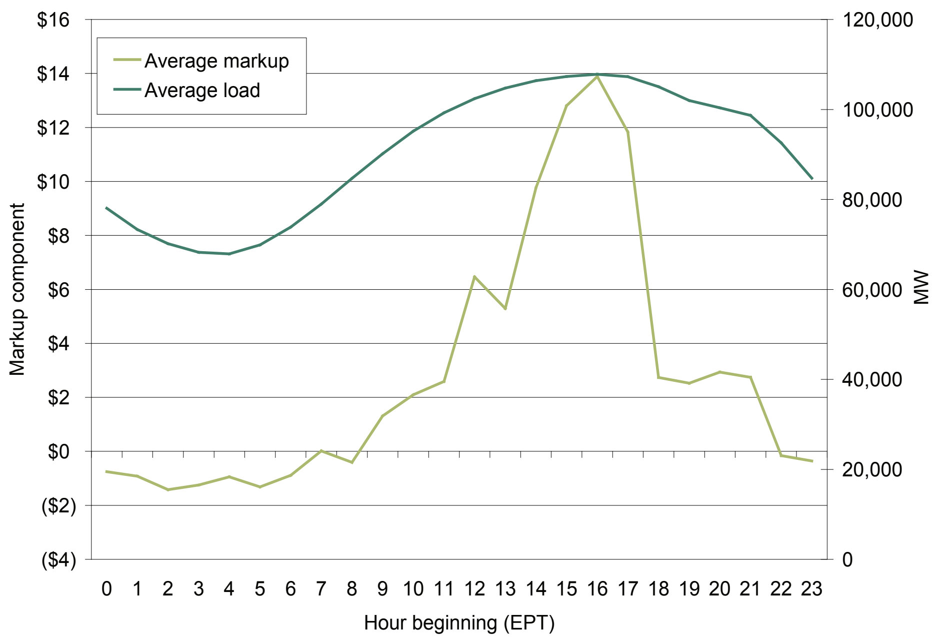


Table 2-39 shows that $0.60 per MWh, or 39 percent, of the total markup component of price occurs on high-load days. In addition, for units subject to offer capping for local market power (non-exempt units), 50 percent of the total markup component of price occurs on high-load days. For units exempt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

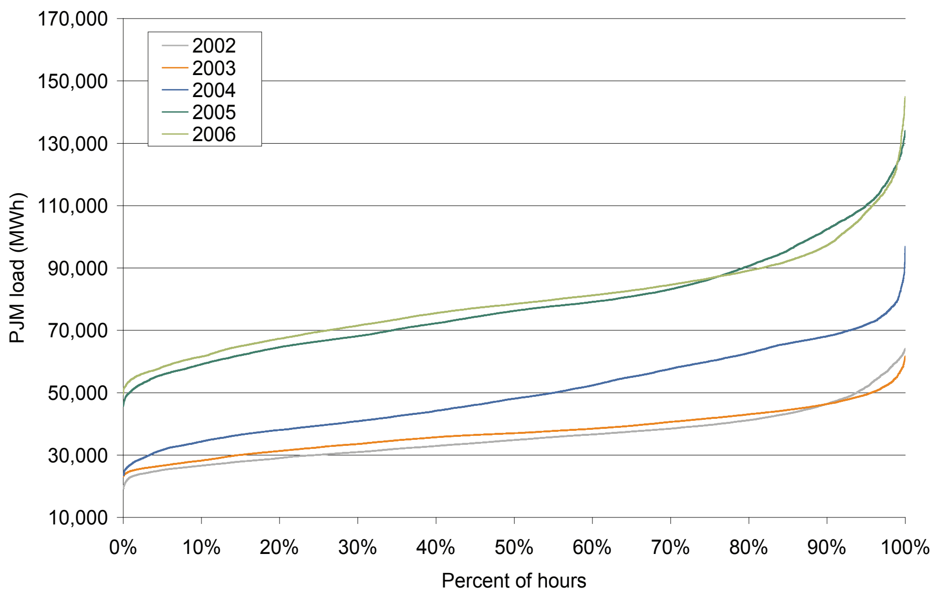
Table 2-40 PJM average real-time load: Calendar years 1998 to 2006

	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.

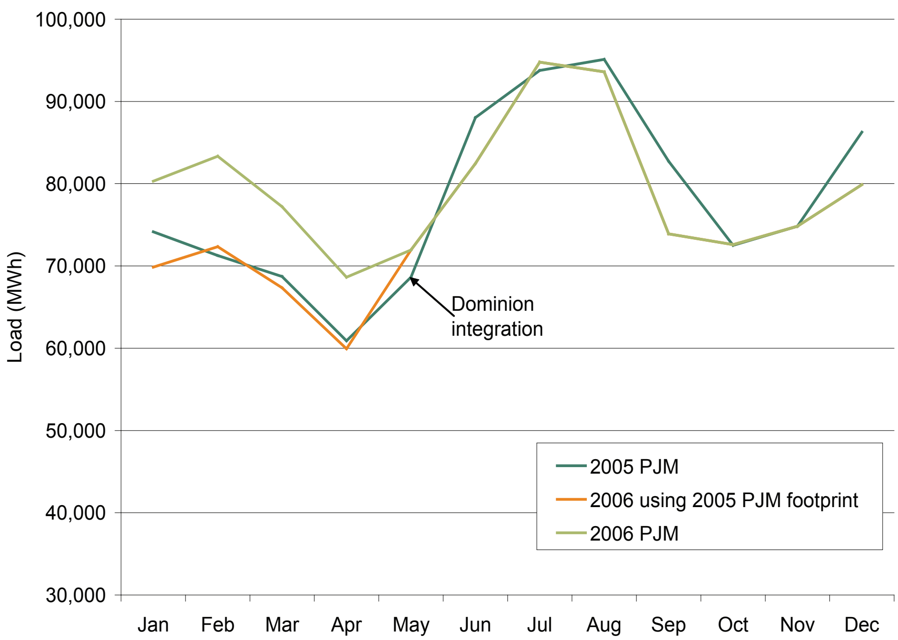
In the Day-Ahead Energy Market, three types of financially binding demand bids are made and cleared:

- **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.

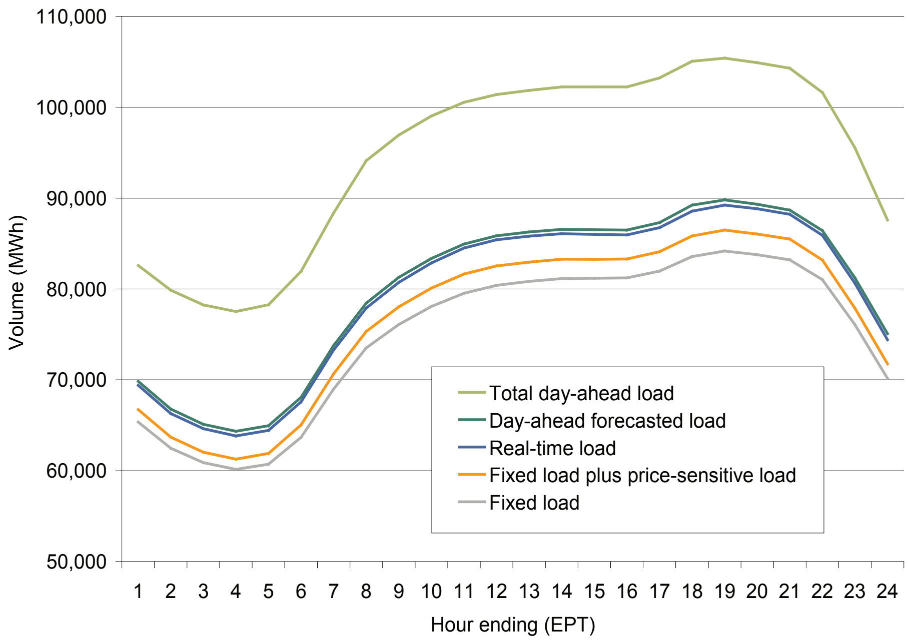
Table 2-42 Cleared day-ahead and real-time load (MWh): Calendar year 2006

	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.

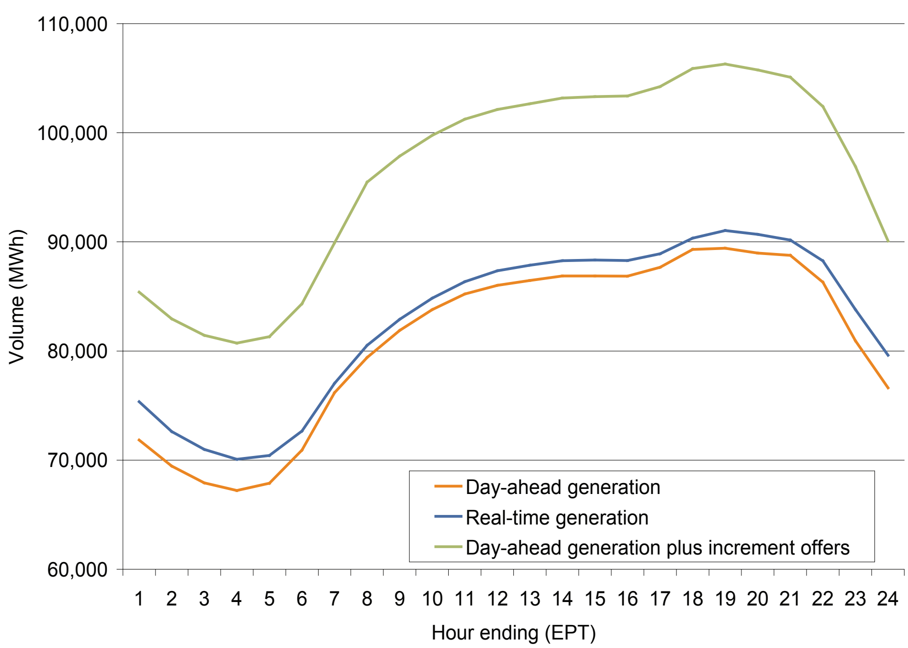
Table 2-43 presents summary statistics for 2006 day-ahead and real-time generation and the average differences between them. Day-ahead cleared generation from physical units averaged 1,828 MWh less than real-time generation. Day-ahead cleared generation plus cleared INC offers averaged 13,543 MWh more 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%)

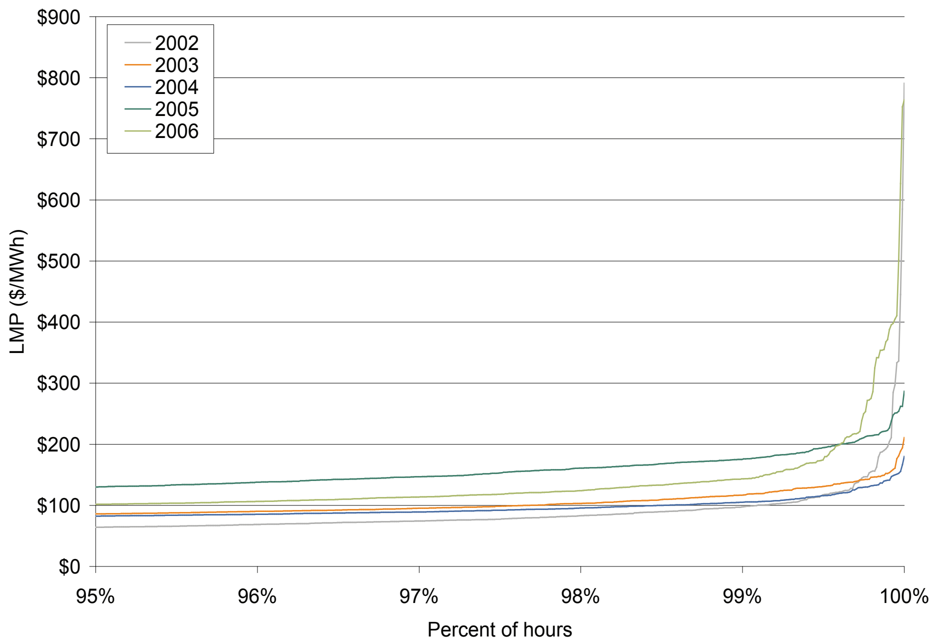
Price Duration

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

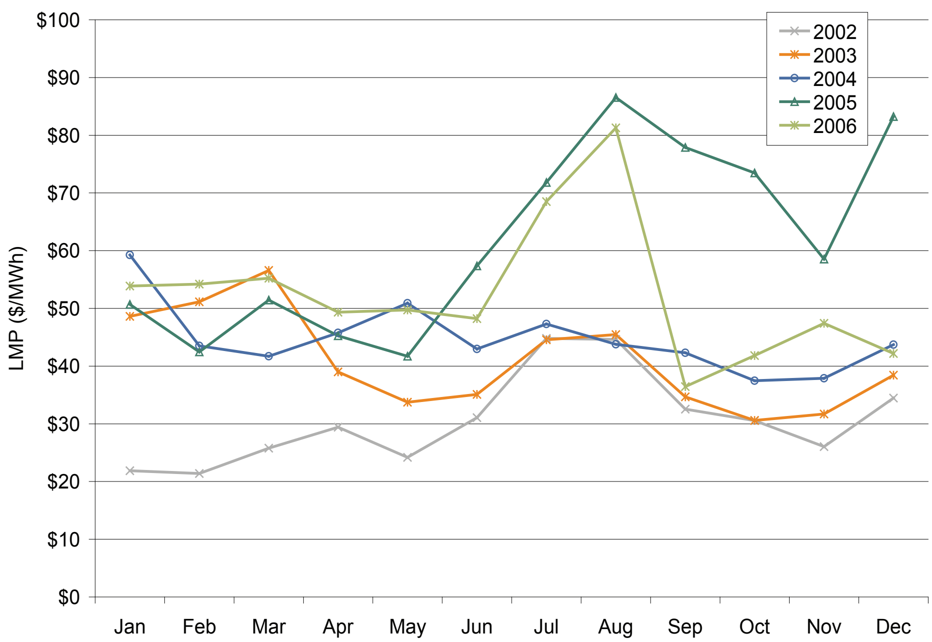
Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than simple average prices. Load-weighted LMP reflects the average LMP paid for actual MWh generated and consumed during a year. Load-weighted LMP is the average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

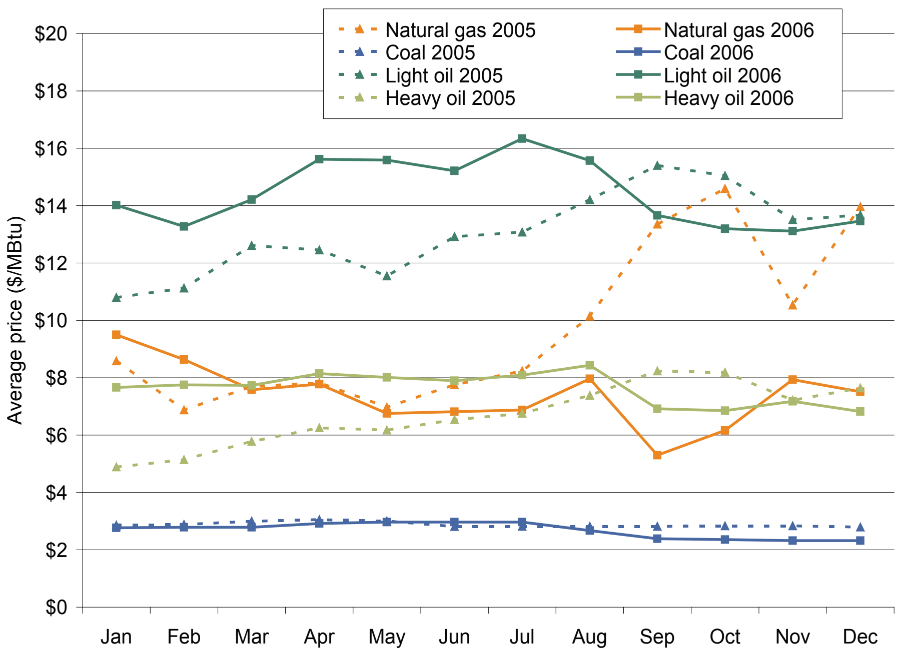
54 See *2006 State of the Market Report*, Volume II, Appendix C, "Energy Market," for on-peak and off-peak, load-weighted LMP details and Appendix H, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

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.

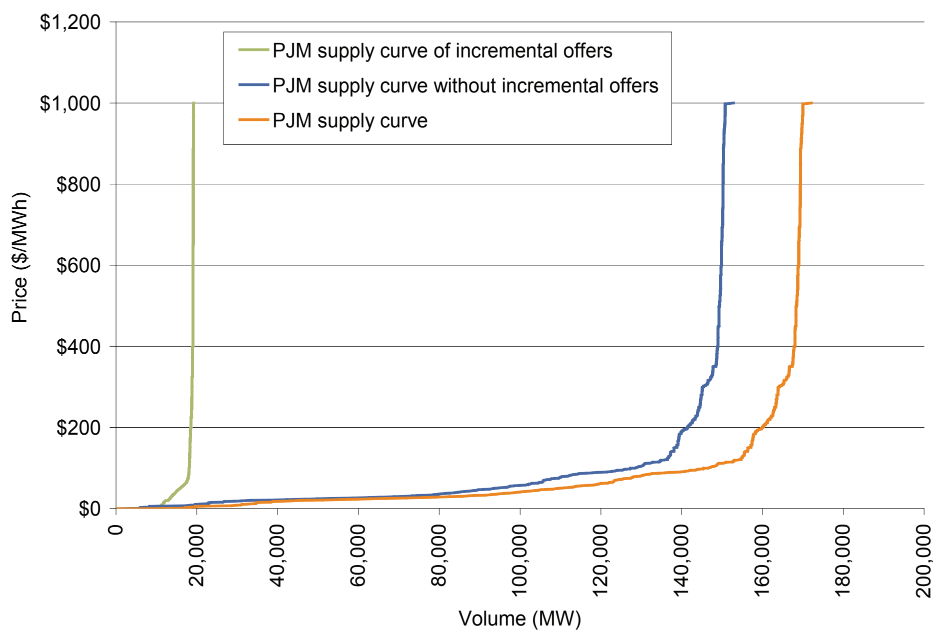
59 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

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

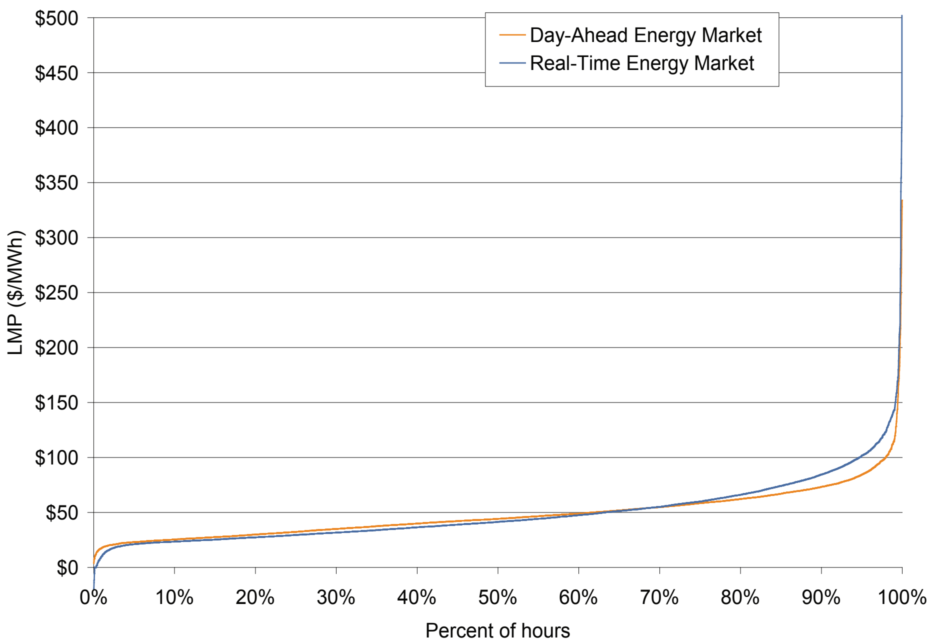


Figure 2-16 shows the hourly differences between day-ahead and real-time LMP in 2006. Although the average difference between the Day-Ahead and Real-Time Energy Market was $1.17 per MWh for the entire year, Figure 2-16 demonstrates the considerable actual variation, both positive and negative, between 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

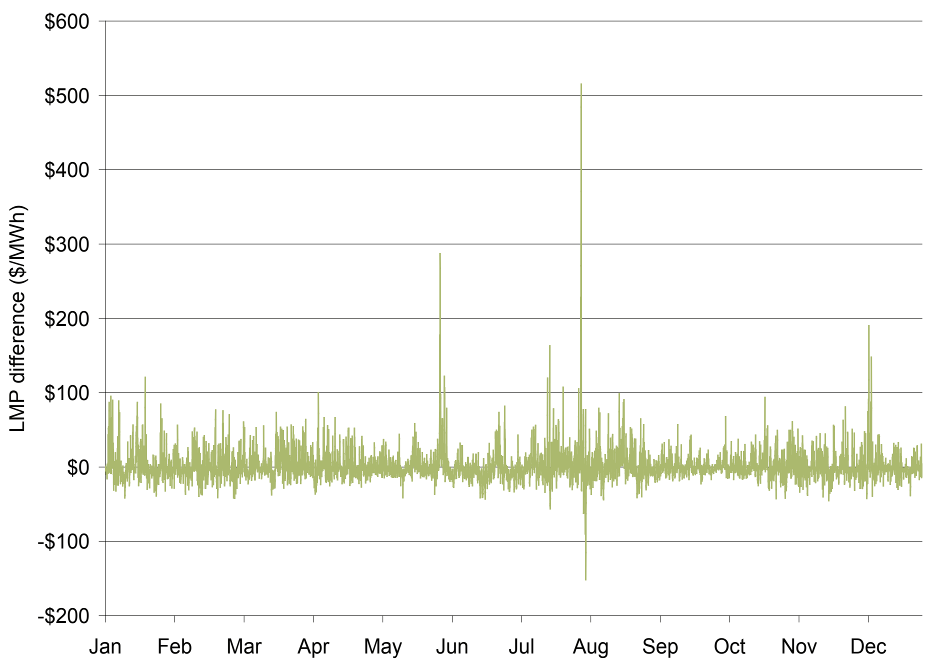


Figure 2-17 shows the monthly differences between day-ahead and real-time LMP in 2006. The highest monthly difference was in August, which was the month with annual peak load and peak system real-time LMP.

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

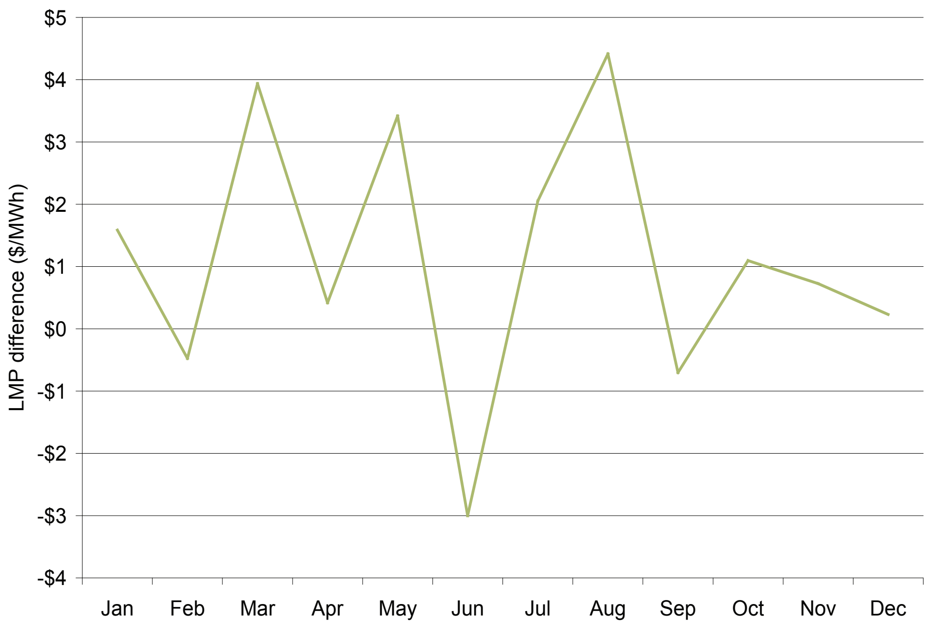
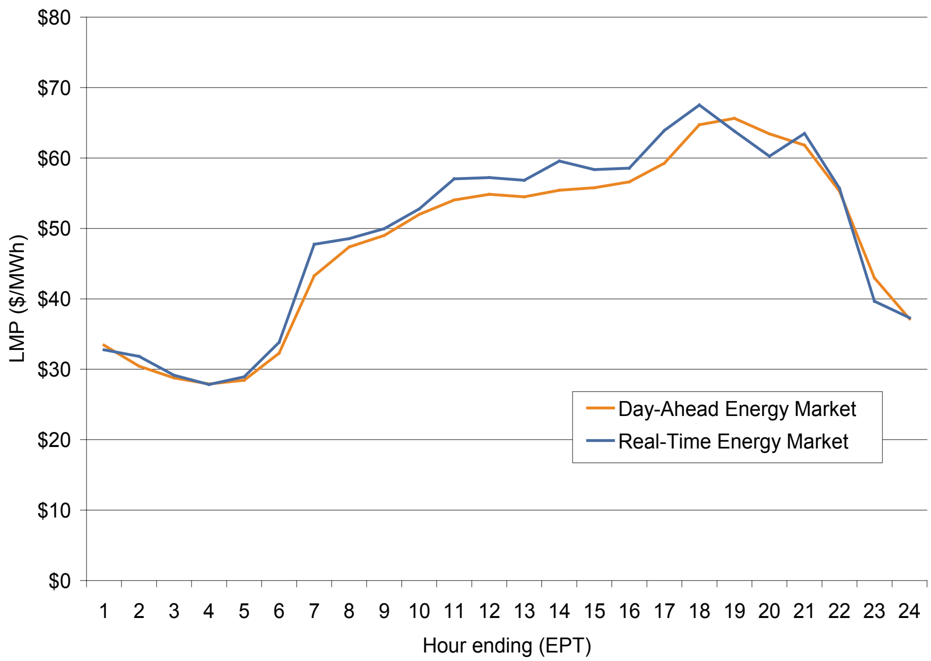


Figure 2-18 shows that day-ahead and real-time LMPs were close on an average hourly basis, but that average real-time LMP was greater than average day-ahead LMP for 19 out of 24 hours.[60]

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.

SECTION 3 – ENERGY MARKET, PART 2

The PJM Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2006. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the nature of new investment in capacity in PJM, the definition and existence of scarcity conditions in PJM and the issues associated with operating reserve credits and charges.

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.[1]

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital cost received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  Analysis of 2006 net revenue, including both the Day-Ahead and Real-Time Energy Market, indicates that the fixed costs of new peaking, midmerit and coal-fired baseload were not fully covered. During the eight-year period 1999 to 2006, the data lead to the conclusion that net revenues were less than the fixed costs of generation and that this shortfall resulted both from lower, less volatile energy market prices and lower capacity credit market prices in the last several years.

  Under an economic dispatch scenario, the eight-year net revenue averaged $30,212 per installed MW-year for a new entrant combustion turbine (CT) plant, $56,120 per installed MW-year for a new entrant combined-cycle (CC) plant and $150,939 per installed MW-year for a new entrant pulverized coal (CP) plant. Thus, under perfect economic dispatch over the eight-year period, the average, net revenue was not adequate to cover the first year's fixed costs for the CT, CC or CP plant.

- **Zonal Net Revenues.** Zonal revenues reflect differentials in locational marginal price (LMP) across the system and illustrate the substantial impact that locational prices have on economic incentives. For a CT, while the PJM average net revenue in 2006 was $10,996 per MW-day, the maximum zonal CT net revenue was $37,801 in the PEPCO control zone and the minimum was $4,342 in the DAY control zone. For a CC, while the PJM average net revenue in 2006 was $44,692 per MW-day, the maximum

1 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."

zonal CC net revenue was $91,120 in the PEPCO control zone and the minimum was $18,897 in the DLCO control zone. For a CP, while the PJM average net revenue in 2006 was $177,852 per MW-day, the maximum zonal CP net revenue was $254,964 in the PEPCO control zone and the minimum was $102,923 in the DLCO control zone.

While the maximum zonal CT net revenue was well below the annual fixed costs of a new CT, the maximum CC zonal net revenue was close to the annual fixed costs of a new CC and the maximum CP zonal net revenue was substantially in excess of the annual fixed costs of a new CP. Thus, the higher LMPs in the eastern PJM zones, reflecting transmission limitations and congestion, have a positive impact on the incentive to invest in those areas.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2006, PJM installed capacity remained relatively flat with the exception of modest changes in imports and exports. Retirements were offset by new additions and the installed capacity on December 31, 2006, was only 884 MW less than on January 1, 2006.

- **PJM Installed Capacity by Fuel Type.** At the end of 2006, PJM installed capacity was 162,143 MW. Of the total installed capacity, 41.0 percent was coal, 29.0 percent was natural gas, 18.5 percent was nuclear, 6.6 percent was oil, 4.4 percent was hydroelectric and 0.4 percent was solid waste.

- **Generation Fuel Mix.** During 2006, coal was 56.8 percent, nuclear 34.6 percent, natural gas 5.5 percent, oil 0.3 percent, hydroelectric 2.0 percent, solid waste 0.7 percent and wind 0.1 percent of total generation.

- **Planned Generation.** If current trends continue, it is expected that older steam units in the east will be replaced by units burning natural gas and the result has potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure.

Scarcity

- **Scarcity.** During the summer of 2006, there were 70 hours of high load that occurred from July 17 through July 19, from July 31 through August 3 and on August 7. Within these 70 hours, there were 10 hours on August 1 and August 2 that met the criteria for potential within-hour scarcity.

- **Scarcity Pricing Events in 2006.** PJM implemented administratively based, scarcity pricing rules in 2006.[2] In 2005 it was recognized that changing market dynamics created by PJM's expanded footprint, along with PJM's continued need for administratively employed emergency mechanisms to maintain system reliability under conditions of scarcity, had created a need for an administratively based scarcity pricing mechanism. Based on the definition of scarcity outlined in the Tariff, there were no official scarcity pricing events in 2006, despite record coincident-peak loads recorded across the PJM footprint and within specific zones.

2 114 FERC ¶61,076 (2006).

- **Modifications to Scarcity Pricing.** While PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions, an analysis of 2006 market results suggests that PJM's current set of scarcity pricing rules may need refinement. The MMU reviewed the summer of 2006 for scarcity conditions and the market prices that resulted. Based on the results, the MMU suggests that PJM's scarcity pricing mechanism be reviewed and modified. The definition of scarcity should include several steps or states of scarcity, each with an associated price, rather than the single step now in the Tariff. Scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. In addition, the actual market signal needs further refinement. Under the current rules, a scarcity pricing event sets prices for all generators in the defined area at the same level, equal to the highest accepted offer within a scarcity pricing region. The single scarcity price signal should be replaced by locational signals.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, operating reserve payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in 2006.** Operating reserve charges were lower in 2006 by 53 percent. The reasons for the substantial decrease in the balancing operating reserve charges included decreased fuel costs and improved operating practices by PJM.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full requirements contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs in well-defined stages with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. With a capacity market design that appropriately reflects scarcity rents in the energy market, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power.

While net revenue in PJM has been almost sufficient to cover the costs of new peaking units in some years and was sufficient to cover the costs of a new coal plant in 2005 and close to covering those costs in 2006 in some eastern zones, net revenue has generally been below the level required to cover the full costs of new generation investment for several years and below that level on average for all unit types for the entire market period. The fact that investors' expectations have not been realized in every year could be taken as a reflection of cyclical supply-demand fundamentals in PJM markets. However, it is also the case that there are some units in PJM, needed for reliability, that have revenues that are not adequate to cover annual going forward costs and that their owners, therefore, wish to retire. This suggests that market price signals and reliability needs are not fully synchronized.

The issue is how to understand this phenomenon and how to address it within the context of competitive markets. The level of net revenues in PJM markets is not the result of the $1,000 per MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market-clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly value the resources needed to provide for reliability, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. Ideally, a capacity market would include a mechanism for equilibrating energy and capacity market revenues such that, in equilibrium, generators receive a market-based return for investing in capacity from all markets taken together. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

The PJM Reliability Pricing Model (RPM) is an effort to address these issues. RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market.

The ultimate test of a competitive market design is whether it provides incentives to invest that are acted upon by market participants, based on incentives endogenous to the competitive market design and not in reliance on the potential or actual exercise of market power. The net revenue performance of the Balancing Energy Market over the last eight years and the Day-Ahead Energy Market over the last seven years illustrates that additional market modifications are necessary if PJM is to pass that test. A combination of the RPM design and enhancements of scarcity pricing are two such modifications.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital cost received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Although generators receive operating reserve payments as a revenue stream, these payments are not included here because the analysis is based on economic dispatch in the PJM model.[3] Gross energy market revenue is the product of the energy market price and generation output. Gross revenues are also received from the Capacity Market and the Ancillary Service Markets. Total gross revenue less variable cost equals net revenue. In other words, net revenue is the amount that remains, after variable costs have been subtracted from gross revenue, to cover fixed costs including a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a unit would operate, rather than based on the analysis of actual net revenues for actual units operating in PJM. In order to provide a more complete analysis, energy net revenues were developed separately for both the Balancing and the Day-Ahead Energy Market.

3 Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost over the day of operation. The PJM model also ensures that generators are compensated for startup and no-load costs when they are dispatched based on marginal costs or on their offer price.

Table 3-1 illustrates the relationship between generator variable cost and net revenue from the PJM Balancing Energy Market alone for the years 1999 through 2006.

Table 3-1 PJM balancing energy market net revenue [By unit marginal cost (Dollars per MWh)]: Calendar years 1999 to 2006

Marginal Cost	1999	2000	2001	2002	2003	2004	2005	2006
$10	$152,087	$150,774	$186,887	$153,620	$231,927	$263,115	$394,619	$322,668
$20	$94,690	$89,418	$116,116	$85,661	$159,751	$185,956	$314,917	$242,179
$30	$72,489	$59,776	$78,368	$51,898	$110,126	$121,218	$241,977	$171,735
$40	$62,367	$39,519	$56,055	$31,650	$73,828	$74,920	$184,479	$120,014
$50	$57,080	$25,752	$42,006	$19,776	$47,277	$44,577	$141,078	$83,857
$60	$54,132	$16,888	$33,340	$13,101	$29,566	$25,328	$107,057	$58,812
$70	$52,259	$11,750	$27,926	$9,080	$18,001	$13,624	$80,473	$41,608
$80	$50,959	$8,586	$24,389	$6,623	$10,650	$6,929	$59,903	$29,643
$90	$49,840	$6,700	$22,080	$5,079	$6,273	$3,494	$44,043	$21,585
$100	$48,818	$5,640	$20,521	$4,109	$3,770	$1,784	$32,184	$16,188
$110	$47,863	$4,930	$19,375	$3,507	$2,250	$951	$23,338	$12,653
$120	$46,926	$4,385	$18,480	$3,063	$1,315	$518	$16,831	$10,283
$130	$46,007	$3,958	$17,716	$2,758	$723	$260	$12,070	$8,645
$140	$45,114	$3,609	$17,030	$2,501	$387	$124	$8,528	$7,466
$150	$44,228	$3,317	$16,421	$2,287	$218	$51	$5,903	$6,667
$160	$43,374	$3,102	$15,884	$2,115	$142	$24	$3,946	$6,030
$170	$42,523	$2,923	$15,395	$1,970	$94	$9	$2,554	$5,508
$180	$41,685	$2,768	$14,944	$1,828	$51	$0	$1,679	$5,083
$190	$40,856	$2,623	$14,542	$1,700	$23	$0	$1,113	$4,699
$200	$40,036	$2,488	$14,162	$1,607	$10	$0	$706	$4,347

Table 3-2 illustrates the relationship between generator variable cost and net revenue from the PJM Day-Ahead Energy Market alone for the years 2000 through 2006.[4]

Table 3-2 PJM day-ahead energy market net revenue [By unit marginal cost (Dollars per MWh)]: Calendar years 2000 to 2006

Marginal Cost	2000	2001	2002	2003	2004	2005	2006
$10	$158,429	$189,366	$154,267	$234,622	$254,455	$392,425	$216,637
$20	$95,823	$115,372	$83,083	$159,572	$176,265	$311,563	$165,614
$30	$61,816	$68,718	$44,916	$102,907	$109,583	$235,006	$117,447
$40	$38,762	$42,283	$25,011	$61,674	$59,650	$173,084	$77,340
$50	$23,141	$27,936	$15,126	$34,891	$27,638	$125,929	$47,954
$60	$14,281	$20,375	$9,894	$19,169	$11,152	$90,176	$29,201
$70	$9,523	$16,304	$6,804	$10,504	$4,039	$63,340	$18,423
$80	$6,840	$13,933	$4,856	$5,858	$1,375	$43,467	$12,613
$90	$5,100	$12,540	$3,522	$3,389	$415	$29,224	$9,180
$100	$3,927	$11,478	$2,570	$1,954	$121	$19,208	$7,037
$110	$3,244	$10,705	$1,885	$1,150	$42	$12,186	$5,742
$120	$2,683	$10,098	$1,385	$620	$14	$7,409	$4,873
$130	$2,299	$9,579	$1,000	$315	$0	$4,361	$4,203
$140	$2,056	$9,139	$712	$148	$0	$2,397	$3,628
$150	$1,884	$8,708	$494	$34	$0	$1,229	$3,136
$160	$1,787	$8,312	$354	$0	$0	$574	$2,703
$170	$1,701	$7,926	$243	$0	$0	$234	$2,314
$180	$1,616	$7,564	$145	$0	$0	$83	$1,991
$190	$1,532	$7,232	$78	$0	$0	$31	$1,717
$200	$1,447	$6,908	$30	$0	$0	$11	$1,475

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the Energy Market would be expected to equal the total of all fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual markets, where equilibrium seldom occurs, net revenue fluctuates annually based on actual conditions in all relevant markets.

4 The Day-Ahead Energy Market began on June 1, 2000. For the analysis presented in Table 3-2, balancing energy market LMP was used from January 1, 2000, to May 31, 2000.

The net revenue analysis includes energy net revenues for both the Balancing and Day-Ahead Energy Market for a natural gas-fired combustion turbine (CT), a two-on-one, natural gas-fired, combined-cycle (CC) plant and a pulverized coal (CP) steam plant as the new entry technologies in order to provide a relatively complete representation of entry conditions. Two dispatch scenarios are analyzed for each new entry technology and Energy Market.

The net revenue analysis includes nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emission market allowance costs in the dispatch rate, adjustments to plant capacity and energy production based on hourly ambient air and river water temperatures, use of unit class-specific forced outage rates and calculation of ancillary service revenues based on actual PJM unit-class experience.

The net revenue calculations under perfect dispatch are an approximate measure, generally representing an upper bound of the markets' direct contribution to generator fixed costs. The energy market net revenue curve does not consider operating constraints that may affect actual net revenue of an individual plant. Such operating constraints are less likely to affect the net revenue calculations for CTs, given their operational flexibility and the operating reserve revenue guarantee. For a CC steam plant, a two-hour hot status notification plus start-up time for a summer weekday could prevent a unit from running during two profitable hours in the afternoon peak and two more profitable hours in the evening peak separated by two unprofitable hours, or could result in reduced net revenues from the unprofitable hours.[5] The actual impact depends on the relationship between locational marginal price (LMP) and the operating costs of the unit. Likewise, a CP steam plant with an eight-hour cold status notification plus start-up time could run overnight during unprofitable hours although the lower relative operating costs of a steam unit would generally reduce the significance of the issue.[6] Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all profitable hours.

Conversely, the net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the real-time price, e.g. a forward price.

In order to provide an approximate lower bound to the perfect economic dispatch net revenues, additional dispatch scenarios were analyzed for each plant type.

Energy Market Net Revenue

The balancing energy market revenues in Table 3-1 and the day-ahead energy market revenues in Table 3-2 reflect net energy market revenues from all hours during 1999 to 2006 for the Balancing Market and 2000 to 2006 for the Day-Ahead Energy Market when the average PJM hourly locational market price exceeded the identified marginal cost of generation. The table includes the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost in dollars per MWh, adjusted for unit forced outages.[7] For example, during 2006, if a unit had

5 A two-hour hot start, including a notification period, is consistent with the CC technology.

6 An eight-hour cold status notification plus startup is consistent with the CP technology.

7 Balancing and day-ahead energy market net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each year. Since this table includes a range of marginal costs from $10 to $200, an outage rate by class cannot be utilized because there is no simple mapping of marginal cost to class of generation, e.g. the $100 range could include steam-oil, gas–fired CC and efficient gas-fired CTs. Class-specific forced outage rates are used for the class-specific net revenue calculations.

marginal costs (fuel plus variable operation and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever the balancing energy market LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2006, adjusted for forced outages, it would have received $171,735 per installed MW-year in net revenue from the Balancing Energy Market alone. For the Day-Ahead Energy Market, the same unit would have received $117,447 per installed MW-year in net revenue from the Day-Ahead Energy Market.[8]

Figure 3-1 displays the information from Table 3-1, and Figure 3-2 displays the information from Table 3-2. As Figure 3-1 illustrates, the balancing energy market net revenue curve was lower in 2006 for every level of unit marginal costs compared to 2005 except for when the balancing energy market LMP was $150 per MWh or higher. The 2006 net revenues for units with marginal costs equal to, or less than, $50 were higher than for any year except 2005 since PJM introduced markets in 1999. As Figure 3-2 shows, the day-ahead energy market net revenue curve for 2006 was close to the average level for every year with the exception of 2005, when net revenues for a unit with marginal costs at or below $110 per MWh would have been higher than any other year.

The decrease in 2006 balancing energy market net revenue compared to 2005 is the result of changes in the frequency distribution of energy prices. In 2006, prices were greater than, or equal to, $30 less frequently than in 2005 as the 2006 simple average LMP was $49.27 per MWh and the simple average LMP in 2005 was higher at $58.08 per MWh. In 1999, the balancing energy market LMP was greater than, or equal to, $30 per MWh during 17 percent of all hours. In 2000, this was 29 percent; in 2001, 34 percent; in 2002, 30 percent; in 2003, 51 percent; in 2004, 68 percent; 81 percent in 2005 and 74 percent in 2006.

The decrease in 2006 as compared to 2005 day-ahead energy market net revenue is also the result of changes in the frequency distribution of energy prices. In 2006, prices were greater than, or equal to, $30 less frequently than in 2005 as the 2006 simple average LMP was $48.10 per MWh and the simple average LMP in 2005 was higher at $57.89 per MWh. In 2000, the day-ahead energy market LMP was greater than or equal to $30 per MWh during 42 percent of all hours. In 2001, this was 42 percent; in 2002, 33 percent; in 2003, 60 percent; in 2004, 72 percent; in 2005, 86 percent and in 2006, 80 percent.

The distribution of prices reflects a number of factors including load levels and fuel costs. An efficient CT could have produced energy at an average cost of $30 in 1999, but $85 in 2006. An efficient CC could have produced energy at an average cost of $20 in 1999, but $65 in 2005. An efficient CP could have produced energy at an average cost of $20 in 1999, but $30 in 2006.

The system average hourly balancing energy market LMP exceeded $200 for 35 hours and exceeded $400 for six hours with the maximum balancing energy market LMP at $736.80. The system average hourly day-ahead energy market LMP exceeded $200 for 25 hours and there were no hours when LMP exceeded $400.

8 This unit would not receive balancing energy market revenues in addition to day-ahead energy market revenues as any energy scheduled in the Day-Ahead Market would be credited at the day-ahead energy market-clearing price and would not be eligible for balancing energy market revenues for that same hour of operation.

Figure 3-1 PJM balancing energy market net revenue (By unit marginal cost): Calendar years 1999 to 2006

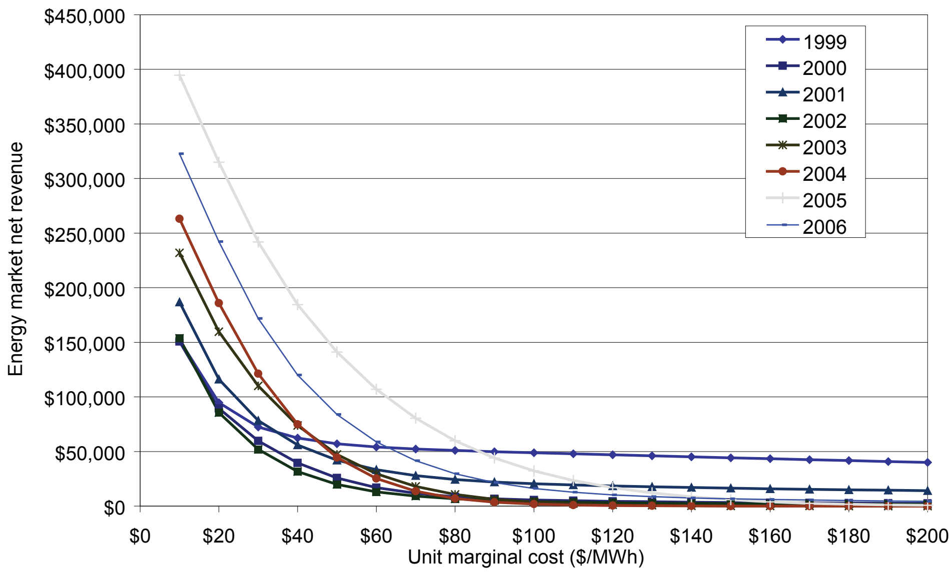
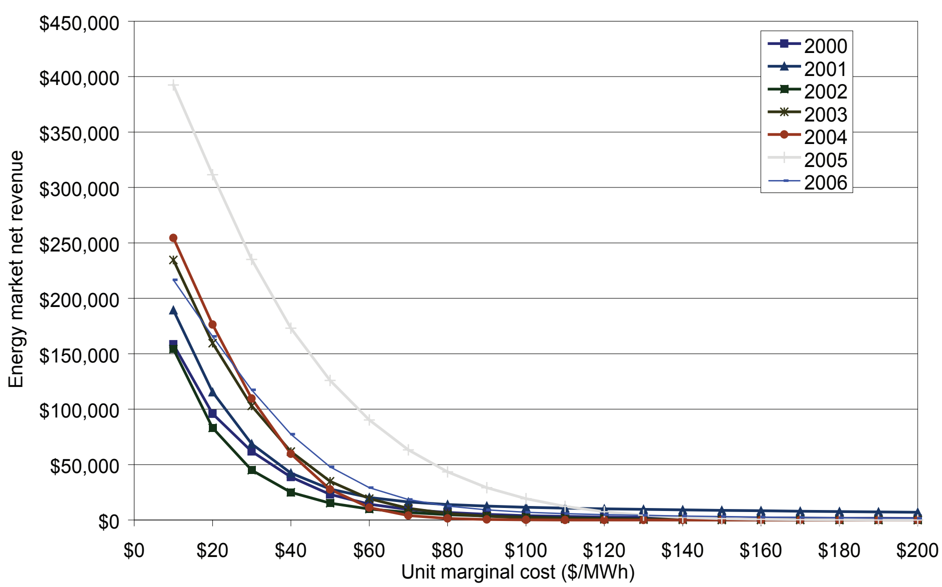


Figure 3-2 PJM day-ahead energy market net revenue (By unit marginal cost): Calendar years 2000 to 2006



Differences in the shape and position of balancing energy market net revenue curves for the eight years result from different distributions of energy market prices. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units.[9] Balancing energy market revenues for 2006 are higher than every year since 1999 for units with a

9 See *2006 State of the Market Report*, Section 2, "Energy Market, Part 1," at "Load and LMP" and Appendix C, "Energy Market" for detailed data on prices and their annual distribution.

marginal cost up to and including $60 with the exception of 2005, primarily because the higher fuel costs of gas-fired marginal units resulted in higher prices and thus higher energy revenues for generators with lower fuel cost. The day-ahead energy market net revenue curves show that the curve for 2006 is similar to every prior year with the exception of 2005 when the net revenues were higher for a unit with marginal costs of $110 per MWh or less.

Capacity Credit Market Net Revenue

Generators receive revenues from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. In 2006, PJM capacity resources received a weighted-average payment from the PJM Capacity Credit Market (CCM) of $5.73 per MW-day of unforced capacity, or $1,958 per MW-year of installed capacity. This is the lowest level of CCM revenues since the opening of PJM markets in 1999.

The CCM price used for net revenue calculations is the composite CCM, excluding ComEd, through May 31, 2005, and the entire PJM footprint from June 1, 2005, forward. The corresponding annual CCM prices are presented in Table 3-3.

Table 3-3 PJM's average annual CCM price: Calendar years 1999 to 2006

	Dollars per Installed MW-Year
1999	$18,124
2000	$20,804
2001	$32,981
2002	$11,600
2003	$5,946
2004	$6,493
2005	$2,089
2006	$1,958

Ancillary Service and Operating Reserve Net Revenue

Generators also receive revenue from the sale of ancillary services, including those from the Synchronized Reserve and Regulation Markets as well as black start and reactive services. Aggregate ancillary service revenues were $3,926 per installed MW-year in 2006. (See Table 3-4.) While actual, generator-specific ancillary service revenues vary with generator technology, ancillary service revenues are expressed here in terms of a system average per installed MW. Theoretical net revenue calculations, addressed later in this section, use more detailed, technology-specific ancillary service estimates.

Table 3-4 System average ancillary service revenues: Calendar years 1999 to 2006

	Dollars per Installed MW-Year
1999	$3,444
2000	$4,509
2001	$3,831
2002	$3,500
2003	$3,986
2004	$3,667
2005	$5,135
2006	$3,926

Although not included in the net revenue analyses, generators also receive operating reserve revenues from both the Day-Ahead and Real-Time Energy Market. Operating reserve payments were about $3,800 per installed MW-year in 2005 and were about $1,600 per installed MW-year in 2006. These payments are designed, in part, to ensure that generators are paid enough to cover their offers, including startup and no-load costs, when scheduled by PJM and that they are not required to run at a loss.

New Entrant Net Revenue Analysis

Analysis of both the balancing and day-ahead energy market net revenues available for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA CTs equipped with evaporative cooling, a single heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator. The coal plant is a western Pennsylvania seam CP, equipped with lime injection for SO_2 reduction and low NO_x burners in conjunction with over fire air for NO_x control.

All net revenue calculations include the use of actual hourly ambient air temperature[10] and river water cooling temperature[11] and the effect of each, as applicable, on plant heat rates[12] and generator output for

10 Hourly ambient conditions supplied by Meteorlogix from the Philadelphia International Airport, Philadelphia, Pennsylvania.

11 Hourly river water conditions represent the Reedy Island Jetty Gauge station located on the Delaware River. Data obtained from U.S. Department of the Interior, U.S. Geological Survey < http://nwis.waterdata.usgs.gov/pa/nwis/qwdata?site_no=01482800>.

12 These heat rate changes were calculated by Pasteris Energy, Inc., a consultant to PJM, utilizing GE Energy's GateCycle Power Plant and Simulation Software. Neither GE Energy nor GE has reviewed this report or the calculations and results of the work done by Pasteris Energy, Inc. for PJM.

each of the three plant configurations.[13] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air and river condition variations.[14] The effect of ambient air conditions and river water temperature on plant generation capability was calculated hourly to adjust for changes in energy production. For purposes of determining the amount of capacity that could be sold in the CCM, the available capacity of each plant type was calculated based on actual ambient conditions at the hour of each annual peak load, consistent with PJM rules for determining available capacity. Available capacity was then adjusted downward by the actual class average forced outage rate for each generator type in order to obtain the level of unforced capacity available for sale in PJM CCM auctions, by plant type.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, where applicable. These costs are included in the PJM definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices for the prompt year.[15] NO_x emission allowance costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 emission allowance costs were calculated for every hour of the year.

A forced outage rate for each class of plant was calculated from PJM data.[16] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a 15-continuous-day, planned annual outage in the fall season.

Variable operation and maintenance (VOM) expenses were estimated to be $5.00 per MWh for the CT plant, $1.50 per MWh for the CC plant and $2.00 per MWh for the CP plant. These estimates were provided by a consultant to PJM and are based on quoted, third-party contract prices.[17] The VOM expenses for the CT and CC plants include accrual of anticipated routine major overhaul expenses.[18] The burner tip fuel cost for natural gas is from published[19] commodity daily cash prices, with a basis adjustment for transportation costs. Coal burner tip cost was developed from the published prompt-month price,[20] adjusted for rail transportation cost. The average burner tip fuel prices are shown in Table 3-5.

Balancing energy market ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 synchronized reserve in PJM. The same is true for the CC configuration. Steam units, like the coal plant, do provide Tier 1 synchronized reserve, but the 2006 Tier 1 revenues were minimal. Balancing energy market ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues. Balancing energy market ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder

13 Pasteris Energy, Inc.

14 All heat rate calculations are expressed in Btu per net kWh. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour, but is off for every uneconomic hour; therefore, there is a single offer point and no offer curve.

15 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets Inc.

16 Outage figures obtained from the PJM eGADS database.

17 Pasteris Energy, Inc.

18 Routine combustor inspection, hot gas path and major inspection costs collected through the VOM adder. This figure was established by Pasteris Energy, Inc. and compares favorably with actual operation and maintenance costs from similar PJM generating units.

19 Gas daily cash prices obtained from Platts.

20 Coal prompt prices obtained from Platts.

of $7.50, per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. The clearing price includes both the offer price and the lost opportunity cost of the marginal unit in each hour. If the reference CP could provide regulation at a total cost, including the CP opportunity cost, that is less than the regulation-clearing price, the regulation service net revenue equals the market price of regulation minus the cost of CP regulation.

Generators receive revenues for the provision of reactive services based on cost of service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. For CTs, the calculated rate is $2,194 per installed MW-year; for CCs, the calculated rate is $3,094 per installed MW-year and for CPs, the calculated rate is $1,692 per installed MW-year.[21]

Table 3-5 Burner tip average fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2006

	Natural Gas	Low Sulfur Coal
1999	$2.62	$1.62
2000	$5.18	$1.39
2001	$4.52	$2.14
2002	$3.81	$1.54
2003	$6.45	$1.76
2004	$6.65	$2.74
2005	$9.73	$2.88
2006	$7.40	$2.68

The balancing energy market perfect dispatch scenario total net revenues for 1999 to 2006 are shown in Table 3-6, Table 3-7 and Table 3-8 for the new entrant CT, CC and CP facilities, respectively.

Table 3-6 PJM balancing energy market new entrant gas-fired CT (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2006

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$62,065	$16,677	$0	$0	$2,248	$80,990
2000	$16,476	$20,200	$0	$0	$2,248	$38,924
2001	$39,269	$30,960	$0	$0	$2,248	$72,477
2002	$23,232	$11,516	$0	$0	$2,248	$36,996
2003	$12,154	$5,554	$0	$0	$2,248	$19,956
2004	$8,063	$5,376	$0	$0	$2,248	$15,687
2005	$15,741	$2,048	$0	$0	$2,248	$20,037
2006	$22,031	$1,758	$0	$0	$2,194	$25,983

21 The CT plant reactive revenues are based on 24 recent filings with the FERC for CT reactive costs. The CC plant revenues are based on 19 recent filings with the FERC for CC reactive costs, and the CP plant revenues are based on eight recent filings with the FERC for CP reactive costs. These figures have been updated from those reported in the *2005 State of the Market Report* to include new generation filings.

Table 3-7 PJM balancing energy market new entrant gas-fired CC (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2006

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$89,600	$16,999	$0	$0	$3,155	$109,754
2000	$42,647	$19,643	$0	$0	$3,155	$65,445
2001	$68,949	$29,309	$0	$0	$3,155	$101,413
2002	$51,639	$10,492	$0	$0	$3,155	$65,286
2003	$50,346	$5,281	$0	$0	$3,155	$58,782
2004	$49,600	$5,241	$0	$0	$3,155	$57,996
2005	$68,308	$2,054	$0	$0	$3,155	$73,517
2006	$70,828	$1,743	$0	$0	$3,094	$75,665

Table 3-8 PJM balancing energy market new entrant CP (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2006

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$101,011	$17,798	$0	$5,596	$1,692	$126,097
2000	$112,202	$20,755	$0	$3,492	$1,692	$138,141
2001	$106,866	$30,862	$0	$1,356	$1,692	$140,776
2002	$101,345	$11,493	$0	$2,118	$1,692	$116,648
2003	$166,540	$5,688	$0	$2,218	$1,692	$176,138
2004	$136,280	$5,537	$0	$1,399	$1,692	$144,908
2005	$232,351	$2,100	$0	$1,727	$1,692	$237,870
2006	$184,241	$1,810	$0	$1,107	$1,692	$188,850

To demonstrate the sensitivity of the CT balancing energy market net revenue results to the assumption of perfect dispatch with no operating constraints, balancing energy market net revenues were calculated for a CT plant dispatched by PJM operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average real-time LMP was greater than, or equal to, the cost to generate, including the cost for a complete start and shutdown cycle[22] for at least two hours during each four-hour block.[23] The blocks were dispatched independently, and, if there were not at least two economic hours in any given block, then the CT was not dispatched. The calculations account for operating reserve based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-6 results.

22 Startup and shutdown fuel burn were obtained from design data for new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Per PJM "Manual M-15: Cost Development Guidelines," Revision 7 (August 3, 2006), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements. No-load costs are included in the heat rate.

23 The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 EPT until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at hour ending 2000 EPT until the hour ending 2300 EPT.

A comparison of the Balancing Energy Market results is shown in Table 3-9, where the first column is the perfect economic dispatch balancing energy market net revenue results from Table 3-6. For the eight-year period, the average balancing energy market net revenue under the perfect economic dispatch scenario was about $24,900 per installed MW-year while the eight-year average for the peak-hour dispatch scenario was about $16,200 per installed MW-year or about a 35 percent reduction in balancing energy market net revenues. Additional, more complex dispatch scenarios were analyzed for the CT plant. The resultant balancing energy market net revenues were about the same as for the peak-hour dispatch scenario.

Table 3-9 Balancing energy market net revenues for a CT under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2006[24]

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
1999	$62,065	$55,612	($6,452)	(10.4%)
2000	$16,476	$8,498	($7,978)	(48.4%)
2001	$39,269	$30,254	($9,015)	(23.0%)
2002	$23,232	$14,496	($8,736)	(37.6%)
2003	$12,154	$2,763	($9,390)	(77.3%)
2004	$8,063	$919	($7,144)	(88.6%)
2005	$15,741	$6,141	($9,600)	(61.0%)
2006	$22,031	$10,996	($11,035)	(50.1%)
Average	$24,879	$16,210	($8,669)	(34.8%)

To demonstrate the sensitivity of the CC balancing energy market net revenue results to the assumption of perfect dispatch with no operating constraints, energy market net revenues were calculated for a CC plant dispatched by PJM operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the average PJM real-time LMP was greater than, or equal to, the cost to generate, including the cost for a complete start and shutdown cycle[25] for at least eight hours during that time period. If there were not eight economic hours in any given day, then the CC was not dispatched. The calculations account for operating reserve based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-7 results.

A comparison of the results is shown in Table 3-10 where the first column is the perfect economic dispatch balancing energy market net revenue results from Table 3-7. For the eight-year period, the average balancing energy market net revenue under the perfect economic dispatch scenario was about $61,500 per installed MW-year while the eight-year average for the peak-hour dispatch scenario is about $41,600 per installed MW-year or about a 32 percent reduction in balancing energy market net revenues. Additional, more

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

25 Startup and shutdown fuel burn obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platts fuel prices. Per PJM "Manual M-15: Cost Development Guidelines," Revision 7 (August 3, 2006), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour and off for every uneconomic hour; therefore, there is a single offer point and no offer curve.

complex dispatch scenarios were analyzed for the CC plant. The resultant balancing energy market net revenues were about the same as for the peak-hour dispatch scenario.

Table 3-10 Balancing energy market net revenues for a CC under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2006

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
1999	$89,600	$80,546	($9,055)	(10.1%)
2000	$42,647	$24,794	($17,854)	(41.9%)
2001	$68,949	$54,206	($14,743)	(21.4%)
2002	$51,639	$38,625	($13,015)	(25.2%)
2003	$50,346	$27,155	($23,191)	(46.1%)
2004	$49,600	$27,389	($22,211)	(44.8%)
2005	$68,308	$35,608	($32,700)	(47.9%)
2006	$70,828	$44,692	($26,136)	(36.9%)
Average	$61,490	$41,627	($19,863)	(32.3%)

To demonstrate the sensitivity of the CP balancing energy market net revenue results to the assumption of perfect dispatch with no operating constraints, balancing energy market net revenues were calculated assuming that the plant had a 24-hour minimum run time and was dispatched by PJM operations for all available plant hours, both reasonable assumptions for a large CP. The calculations account for full operating reserve, when applicable, since the assumed operation is under the direction of PJM operations. The additional dispatch scenario uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-8 results.[26]

26 No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour, and at off for every uneconomic hour; therefore, there is a single offer point and no offer curve.

A comparison of the results is shown in Table 3-11 where the first column is the perfect economic dispatch balancing energy market net revenue results from Table 3-8. For the eight-year period, the average balancing energy market net revenue under the perfect economic dispatch scenario was about $142,600 per installed MW-year while the eight-year average for the available dispatch scenario is about $134,900 per installed MW-year or about a 5 percent reduction in balancing energy market net revenues.

Table 3-11 Balancing energy market net revenues for a CP under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2006

	Perfect Economic Dispatch	All Available Hour Economic	Difference	Percent Difference
1999	$101,011	$92,935	($8,076)	(8.0%)
2000	$112,202	$108,624	($3,578)	(3.2%)
2001	$106,866	$95,361	($11,506)	(10.8%)
2002	$101,345	$96,828	($4,517)	(4.5%)
2003	$166,540	$159,912	($6,628)	(4.0%)
2004	$136,280	$124,497	($11,783)	(8.6%)
2005	$232,351	$222,911	($9,440)	(4.1%)
2006	$184,241	$177,852	($6,389)	(3.5%)
Average	$142,605	$134,865	($7,740)	(5.4%)

In order to develop a comprehensive net revenue analysis, day-ahead energy market net revenues[27, 28] were calculated for the CT, CC and CP class types for both the perfect economic dispatch and peak-hour dispatch scenarios as presented with regard to the balancing energy market analysis. The results for the Day-Ahead Energy Market for each class are listed in Table 3-12, Table 3-13 and Table 3-14, respectively.

Table 3-12 Day-ahead energy market net revenues for a CT under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
2000	$13,419	$7,418	($6,001)	(44.7%)
2001	$25,432	$20,390	($5,042)	(19.8%)
2002	$18,343	$13,921	($4,421)	(24.1%)
2003	$3,884	$1,282	($2,601)	(67.0%)
2004	$520	$1	($519)	(99.8%)
2005	$6,720	$2,996	($3,724)	(55.4%)
2006	$8,608	$5,229	($3,379)	(39.3%)
Average	$10,989	$7,320	($3,670)	(33.4%)

27 The day-ahead energy market net revenues were calculated utilizing the same fuel, weather and unit operational assumptions as were used for the balancing energy market net revenue calculations.

28 The Day-Ahead Energy Market was initialized on June 1, 2000. For the analysis presented in Table 3-12, Table 3-13 and Table 3-14, the balancing energy market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-13 Day-ahead energy market net revenues for a CC under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Perfect Economic Dispatch	Peak Hour Economic	Difference	Percent Difference
2000	$40,374	$26,132	($14,242)	(35.3%)
2001	$58,004	$48,253	($9,751)	(16.8%)
2002	$45,033	$35,993	($9,039)	(20.1%)
2003	$35,825	$21,865	($13,960)	(39.0%)
2004	$31,674	$18,193	($13,482)	(42.6%)
2005	$50,022	$28,413	($21,610)	(43.2%)
2006	$46,636	$31,670	($14,966)	(32.1%)
Average	$43,938	$30,074	($13,864)	(31.6%)

Table 3-14 Day-ahead energy market net revenues for a CP under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Perfect Economic Dispatch	All Available Hour Economic	Difference	Percent Difference
2000	$120,935	$116,784	($4,151)	(3.4%)
2001	$105,076	$95,119	($9,957)	(9.5%)
2002	$100,641	$97,493	($3,148)	(3.1%)
2003	$167,308	$162,285	($5,022)	(3.0%)
2004	$125,416	$113,892	($11,524)	(9.2%)
2005	$226,137	$220,824	($5,314)	(2.3%)
2006	$171,653	$167,282	($4,371)	(2.5%)
Average	$145,309	$139,097	($6,212)	(4.3%)

For the seven-year period, the average day-ahead energy market net revenue under the perfect economic dispatch scenario for the CT plant was about $11,000 per installed MW-year, while the seven-year average for the peak-hour dispatch scenario was about $7,300 per installed MW-year, a 33 percent difference in day-ahead energy market net revenues. For the CC plant, the seven-year average day-ahead energy market net revenue under the perfect dispatch scenario was about $43,900 per installed MW-year while the seven-year average for the peak-hour dispatch scenario was about $30,100 per installed MW-year, a 32 percent difference in day-ahead energy market net revenues. For the CP plant, the seven-year average day-ahead energy market net revenue under the perfect dispatch scenario was about $145,300 per installed MW-year while the seven-year average for the available-hour dispatch scenario was about $139,100 per installed MW-year, a 4 percent difference.

The energy net revenues for both the Balancing and Day-Ahead Energy Market are shown in Table 3-15, Table 3-16 and Table 3-17 for the CT, CC and CP plant, respectively. For the CT plant, the perfect dispatch scenario balancing energy market net revenue averaged about $19,600 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $11,000 per installed MW-year over the same period, a difference of about 44 percent between the two

Energy Markets.[29] For the CT plant in the peak-hour dispatch scenario, the balancing energy market net revenue averaged about $10,600 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $7,300 per installed MW-year over the same period, a difference of about 31 percent between the two Energy Markets.

For the CC plant, the perfect dispatch scenario balancing energy market net revenue averaged about $57,500 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $43,900 per installed MW-year over the same period, a difference of about 24 percent between the two Energy Markets. For the CC plant in the peak-hour dispatch scenario, the balancing energy market net revenue averaged about $36,100 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $30,100 per installed MW-year over the same period, a difference of about 17 percent between the two markets.

For the CP plant, the perfect dispatch scenario balancing energy market net revenue averaged about $148,600 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $145,300 per installed MW-year for the same period, a difference of about 2 percent between the two Energy Markets. For the CP plant in the available-hour dispatch scenario, the balancing energy market net revenue averaged about $140,900 per installed MW-year over the seven-year period from 2000 to 2006 while the day-ahead energy market net revenue averaged about $139,100 per installed MW-year over the same period, a difference of about 1 percent between the two markets.

Table 3-15 Balancing and day-ahead energy market net revenues for a CT under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Balancing Perfect Economic Dispatch	Day Ahead Perfect Economic Dispatch	Perfect Economic Dispatch Difference	Perfect Economic Dispatch Percent Difference	Balancing Peak Hour Economic	Day Ahead Peak Hour Economic	Peak Hour Economic Dispatch Difference	Peak Hour Economic Dispatch Percent Difference
2000	$16,476	$13,419	($3,058)	(18.6%)	$8,498	$7,418	($1,080)	(12.7%)
2001	$39,269	$25,432	($13,837)	(35.2%)	$30,254	$20,390	($9,864)	(32.6%)
2002	$23,232	$18,343	($4,890)	(21.0%)	$14,496	$13,921	($575)	(4.0%)
2003	$12,154	$3,884	($8,270)	(68.0%)	$2,763	$1,282	($1,481)	(53.6%)
2004	$8,063	$520	($7,543)	(93.6%)	$919	$1	($918)	(99.9%)
2005	$15,741	$6,720	($9,021)	(57.3%)	$6,141	$2,996	($3,145)	(51.2%)
2006	$22,031	$8,608	($13,423)	(60.9%)	$10,996	$5,229	($5,767)	(52.4%)
Average	$19,567	$10,989	($8,577)	(43.8%)	$10,581	$7,320	($3,262)	(30.8%)

29 The Day-Ahead Energy Market was initialized on June 1, 2000. For the analysis presented in Table 3-15, Table 3-16 and Table 3-17, the balancing energy market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-16 Balancing and day-ahead energy market net revenues for a CC under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Balancing Perfect Economic Dispatch	Day Ahead Perfect Economic Dispatch	Perfect Economic Dispatch Difference	Perfect Economic Dispatch Percent Difference	Balancing Peak Hour Economic	Day Ahead Peak Hour Economic	Peak Hour Economic Dispatch Difference	Peak Hour Economic Dispatch Percent Difference
2000	$42,647	$40,374	($2,274)	(5.3%)	$24,794	$26,132	$1,338	5.4%
2001	$68,949	$58,004	($10,945)	(15.9%)	$54,206	$48,253	($5,953)	(11.0%)
2002	$51,639	$45,033	($6,607)	(12.8%)	$38,625	$35,993	($2,631)	(6.8%)
2003	$50,346	$35,825	($14,521)	(28.8%)	$27,155	$21,865	($5,290)	(19.5%)
2004	$49,600	$31,674	($17,925)	(36.1%)	$27,389	$18,193	($9,196)	(33.6%)
2005	$68,308	$50,022	($18,286)	(26.8%)	$35,608	$28,413	($7,196)	(20.2%)
2006	$70,828	$46,636	($24,192)	(34.2%)	$44,692	$31,670	($13,023)	(29.1%)
Average	$57,474	$43,938	($13,536)	(23.6%)	$36,067	$30,074	($5,993)	(16.6%)

Table 3-17 Balancing and day-ahead energy market net revenues for a CP under two dispatch scenarios (Dollars per installed MW-year): Calendar years 2000 to 2006

	Balancing Perfect Economic Dispatch	Day Ahead Perfect Economic Dispatch	Perfect Economic Dispatch Difference	Perfect Economic Dispatch Percent Difference	Balancing Available Hour Economic	Day Ahead Available Hour Economic	Available Hour Economic Dispatch Difference	Available Hour Economic Dispatch Percent Difference
2000	$112,202	$120,935	$8,732	7.8%	$108,624	$116,784	$8,159	7.5%
2001	$106,866	$105,076	($1,791)	(1.7%)	$95,361	$95,119	($242)	(0.3%)
2002	$101,345	$100,641	($704)	(0.7%)	$96,828	$97,493	$665	0.7%
2003	$166,540	$167,308	$768	0.5%	$159,912	$162,285	$2,374	1.5%
2004	$136,280	$125,416	($10,864)	(8.0%)	$124,497	$113,892	($10,605)	(8.5%)
2005	$232,351	$226,137	($6,214)	(2.7%)	$222,911	$220,824	($2,087)	(0.9%)
2006	$184,241	$171,653	($12,588)	(6.8%)	$177,852	$167,282	($10,571)	(5.9%)
Average	$148,547	$145,309	($3,237)	(2.2%)	$140,855	$139,097	($1,758)	(1.2%)

Zonal Net Revenue

In order to show how net revenue varies by location, balancing energy market net revenues were calculated for each of the 17 current PJM transmission zones for the economic dispatch scenarios. The results are presented in Table 3-18, Table 3-19 and Table 3-20 for the CT, CC and CP. Net revenues are shown for a transmission zone only if that zone was integrated into PJM for the entire calendar year. The tables show the balancing energy market net revenue using PJM average prices and the differential net revenues for each zone. For example, in Table 3-18 the 2006 calendar year net revenue for a CT plant using the average PJM LMP is $10,996 per installed MW-year. The net revenue for the same plant located in the ComEd transmission zone is $3,865 per installed MW-year less than the PJM average net revenue or $7,131 per installed MW-year.

Table 3-18 Balancing energy market net revenue differentials by transmission zone for a CT under peak-hour dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$16,210
AECO	$666	$3,579	$10,571	$4,952	$2,511	$5,846	$12,168	$12,169	$6,558
AEP	NA	NA	NA	NA	NA	NA	($5,501)	($6,358)	($5,929)
AP	NA	NA	NA	NA	($1,694)	($55)	($952)	($301)	($751)
BGE	($842)	($1,305)	($7,206)	$5,553	$1,433	$1,980	$16,152	$20,729	$4,562
ComEd	NA	NA	NA	NA	NA	NA	($4,394)	($3,865)	($4,130)
DAY	NA	NA	NA	NA	NA	NA	($5,348)	($6,654)	($6,001)
Dominion	NA	NA	NA	NA	NA	NA	NA	$15,834	$15,834
DPL	$2,013	$4,214	$19,579	$7,933	$2,824	$1,962	$8,117	$6,269	$6,614
DLCO	NA	NA	NA	NA	NA	NA	($5,477)	($5,588)	($5,532)
JCPL	$334	$1,305	$7,219	($563)	$218	$13,553	$10,792	$4,936	$4,724
Met-Ed	($614)	($430)	$443	$2,875	$840	$1,352	$9,032	$6,507	$2,501
PECO	$897	$3,262	$7,735	$265	$2,072	$681	$9,972	$4,604	$3,686
PENELEC	($615)	($1,138)	($12,117)	($2,379)	($1,033)	$345	($3,025)	($4,411)	($3,047)
PEPCO	($1,057)	($1,476)	($12,146)	$7,528	$1,847	$2,996	$19,698	$26,805	$5,524
PPL	($307)	($745)	($3,506)	($1,907)	($498)	$201	$6,262	$2,616	$264
PSEG	$659	$1,673	$6,564	($997)	$1,791	$12,244	$10,740	$4,984	$4,707
RECO	NA	NA	NA	NA	$1,450	$2,830	$6,829	$2,610	$3,430

Table 3-19 Balancing energy market net revenues by transmission zone for a CC under peak-hour dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$41,627
AECO	$384	$4,560	$14,116	$7,578	$8,502	$25,236	$41,615	$33,796	$16,974
AEP	NA	NA	NA	NA	NA	NA	($23,075)	($22,997)	($23,036)
AP	NA	NA	NA	NA	($8,120)	($7,226)	$140	($2,958)	($4,541)
BGE	($1,873)	($3,504)	($11,631)	$6,416	$2,009	$6,150	$40,073	$38,953	$9,574
ComEd	NA	NA	NA	NA	NA	NA	($13,829)	($13,961)	($13,895)
DAY	NA	NA	NA	NA	NA	NA	($23,737)	($24,986)	($24,361)
Dominion	NA	NA	NA	NA	NA	NA	NA	$33,575	$33,575
DPL	$3,203	$9,263	$25,302	$10,539	$6,758	$11,702	$25,558	$16,379	$13,588
DLCO	NA	NA	NA	NA	NA	NA	($24,828)	($25,795)	($25,311)
JCPL	$171	$1,031	$6,969	($1,646)	($200)	$35,811	$31,660	$11,675	$10,684
Met-Ed	($1,018)	($1,799)	($867)	$2,845	$218	$3,890	$21,743	$14,625	$4,955
PECO	$710	$3,216	$7,319	($236)	$4,334	$7,181	$25,604	$12,657	$7,598
PENELEC	($825)	($1,783)	($14,733)	$3,446	($4,226)	($5,929)	($8,998)	($14,220)	($5,909)
PEPCO	($2,203)	($3,929)	($17,254)	$7,729	$2,758	$8,813	$46,819	$46,428	$11,145
PPL	($619)	($2,672)	($6,162)	($4,000)	($1,877)	($2,701)	$16,078	$8,166	$777
PSEG	$2,031	$3,857	$8,262	($856)	$7,394	$36,186	$42,573	$21,754	$15,150
RECO	NA	NA	NA	NA	$6,523	$17,084	$28,462	$16,818	$17,222

Table 3-20 Balancing energy market net revenues by transmission zone for a CP under available-hour dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$134,865
AECO	($403)	$4,813	$13,427	$9,139	$9,060	$43,113	$78,227	$50,812	$26,023
AEP	NA	NA	NA	NA	NA	NA	($79,980)	($55,721)	($67,851)
AP	NA	NA	NA	NA	($19,734)	($10,309)	$2,372	($4,466)	($8,034)
BGE	($2,718)	($8,936)	($13,627)	$6,984	$3,328	$14,301	$74,387	$65,763	$17,435
ComEd	NA	NA	NA	NA	NA	NA	($86,856)	($60,717)	($73,786)
DAY	NA	NA	NA	NA	NA	NA	($90,661)	($63,693)	($77,177)
Dominion	NA	NA	NA	NA	NA	NA	NA	$57,810	$57,810
DPL	$3,237	$16,300	$34,385	$12,672	$9,046	$26,280	$57,944	$30,192	$23,757
DLCO	NA	NA	NA	NA	NA	NA	($103,567)	($74,930)	($89,248)
JCPL	($684)	($2,968)	$4,006	($2,167)	($4,348)	$52,608	$61,516	$20,743	$16,088
Met-Ed	($1,882)	($6,606)	($2,989)	$2,330	($2,781)	$10,564	$46,989	$27,655	$9,160
PECO	($13)	$3,419	$6,197	($715)	$4,029	$19,888	$56,395	$25,300	$14,313
PENELEC	($1,046)	$783	($11,268)	$10,617	($5,617)	($9,954)	($12,675)	($21,129)	($6,286)
PEPCO	($3,061)	($9,274)	($19,896)	$8,297	$5,083	$17,880	$84,956	$77,111	$20,137
PPL	($1,488)	($7,771)	($8,779)	($6,873)	($7,237)	$2,515	$37,656	$18,497	$3,315
PSEG	$2,260	$12,781	$12,797	($388)	$14,249	$56,021	$86,959	$41,915	$28,324
RECO	NA	NA	NA	NA	$16,766	$34,691	$69,538	$35,997	$39,248

Net Revenue Adequacy

To put the net revenue results in perspective, the first operating year's annual fixed costs[30] for the assumed new entrant CT plant configuration would be about $68,700 per installed MW-year[31] or about $80,300 per installed MW-year if levelized over the 20-year life of the project.[32] The first operating year's annual fixed cost for the assumed CC and CP plant configurations would be about $84,800 per installed MW-year and $228,900 per installed MW-year, respectively.[33] The levelized 20-year operating annual costs for the CC and CP plants would be about $99,200 per installed MW-year and $267,800 per installed MW-year, respectively. Table 3-21 shows the first-year fixed costs and 20-year operating life levelized costs for each technology.[34]

30 The annual fixed costs for all three new entry plant configurations were re-evaluated for the *2006 State of the Market Report* and the fixed costs are now higher than previous state of the market reports. The 2006 update has been incorporated into Table 3-21 through Table 3-25.

31 Installed capacity at 92 degrees F.

32 This analysis was performed for PJM by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target equity internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

33 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2006.

34 The figures in Table 3-21 represent the annual cost for the first year of operation. For example, the $68,657 per installed MW-year figure represents the annual cost of the CT for the first operational year of the plant. Assuming a two-year construction period, the cost for the first year of construction would be $65,349 per installed MW-year.

Table 3-21 New entrant first-year and 20-year levelized fixed costs [By plant type (Dollars per installed MW-year)]

	First-Year Fixed Cost	20-Year Levelized Fixed Cost
CT	$68,657	$80,315
CC	$84,826	$99,230
CP	$228,922	$267,792

In 2006, under the perfect economic dispatch scenario, net revenue from the Balancing Energy Market, the CCM and the Ancillary Service Markets for a new entrant CT were approximately $26,000 per installed MW-year. The associated operating costs were between $80 and $90 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $7.40 per MBtu and a VOM rate of $5 per MWh.[35] The resulting net revenue stream would not have covered the fixed costs of a new CT if it ran during all profitable hours.

In 2006, under the perfect economic dispatch scenario, net revenue from the Balancing Energy Market, the CCM and the Ancillary Service Markets for a new entrant CC were approximately $75,700 per installed MW-year. The associated operating costs were between $60 and $70 per MWh, based on a design heat rate of 7,150 Btu per kWh, average daily delivered natural gas prices of $7.40 per MBtu and a VOM rate of $1.50 per MWh. The resulting net revenue stream would not have covered the fixed costs of the CC plant if it ran during all profitable hours.

In 2006, under the perfect economic dispatch scenario, net revenue from the Energy Market, the CCM and the Ancillary Service Markets for a new entrant CP would have been approximately $188,900 per installed MW-year. The associated operating costs would have ranged between $30 and $35 per MWh,[36] based on a design heat rate of 9,500 Btu per kWh, average delivered coal prices of $2.68 per MBtu and a VOM rate of $2 per MWh. This revenue stream would not have covered the fixed costs of a CP plant if it ran during all profitable hours.

In 1999 and 2001, the net revenue shown for the CT and CC plants was sufficient to cover the first year's fixed costs as shown in Table 3-22 and Table 3-23, respectively. In 2000 and 2002 through 2006, there was, however, a revenue shortfall for both plant types. For the CP, 2005 was the only year with sufficient net revenues to cover the first year's fixed cost as shown in Table 3-24.

Under the perfect economic dispatch scenario, the eight-year net revenue averaged $38,900 per installed MW-year for a new entrant CT plant, $76,000 per installed MW-year for a new entrant CC plant and $158,700 per installed MW-year for a new entrant CP plant. Thus, under perfect economic dispatch over the eight-year period, the average net revenue was not adequate to cover the first year's fixed costs for the CT, CC or CP plant.

35 The analysis used the daily gas costs and associated production costs for CTs and CCs.

36 The analysis used the prompt coal costs and associated production costs for CPs.

Table 3-22 CT 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2006

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$80,990	112%	$74,537	103%
2000	$72,207	$38,924	54%	$30,946	43%
2001	$72,207	$72,477	100%	$63,462	88%
2002	$72,207	$36,996	51%	$28,260	39%
2003	$72,207	$19,956	28%	$10,565	15%
2004	$72,207	$15,687	22%	$8,543	12%
2005	$72,207	$20,037	28%	$10,437	14%
2006	$80,315	$25,983	32%	$14,948	19%
Average	$73,221	$38,881	53%	$30,212	42%

Table 3-23 CC 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2006

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$109,754	117%	$100,700	108%
2000	$93,549	$65,445	70%	$47,592	51%
2001	$93,549	$101,413	108%	$86,670	93%
2002	$93,549	$65,286	70%	$52,272	56%
2003	$93,549	$58,782	63%	$35,591	38%
2004	$93,549	$57,996	62%	$35,785	38%
2005	$93,549	$73,517	79%	$40,817	44%
2006	$99,230	$75,665	76%	$49,529	50%
Average	$94,259	$75,982	81%	$56,120	60%

Table 3-24 CP 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2006

	20-Year Levelized Fixed Cost	Perfect Dispatch Net Revenue	Perfect Dispatch Percent	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$126,097	61%	$118,021	57%
2000	$208,247	$138,141	66%	$134,563	65%
2001	$208,247	$140,776	68%	$129,271	62%
2002	$208,247	$116,648	56%	$112,131	54%
2003	$208,247	$176,138	85%	$169,510	81%
2004	$208,247	$144,908	70%	$133,125	64%
2005	$208,247	$237,870	114%	$228,430	110%
2006	$267,792	$188,850	71%	$182,461	68%
Average	$215,690	$158,679	74%	$150,939	70%

Table 3-22 through Table 3-24 show net revenues under the perfect dispatch and economic scenarios compared to the 20-year levelized fixed costs of each plant type. During the eight-year period from 1999 to 2006, the CT plant recovered 53 percent of the average 20-year levelized fixed costs under the perfect dispatch scenario and 42 percent under the economic scenario. During that same period the CC plant recovered 81 percent of the average fixed costs under the perfect dispatch scenario and 60 percent under the economic and the CP recovered 74 percent of the average fixed costs under the perfect dispatch scenario and 70 percent under the economic dispatch scenario.

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. Analysis of 2006 net revenue indicates that the fixed costs of new peaking, midmerit and coal-fired baseload were not covered. During the eight-year period 1999 to 2006, the data lead to the conclusion that generators' net revenues were less than the fixed costs of generation and that this shortfall emerged from lower, less volatile Energy Market and lower CCM prices.

Shortfalls in net revenue affect the returns earned by new generating units. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on equity for an investment in a new generating unit. The return on equity was calculated for a range of 20-year levelized net revenue streams, assuming the *2006 State of the Market Report*, 20-year levelized fixed costs from Table 3-21. Levelized net revenues were modified and the return on equity calculated. A $5,000 per MW-year sensitivity was used for the CT and CC and a $10,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-25.[37]

37 This analysis was performed for PJM by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target equity internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20- year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

Table 3-25 Return on equity sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$85,315	13.8%	$104,230	13.4%	$277,792	13.2%
Base Case	$80,315	12.0%	$99,230	12.0%	$267,792	12.0%
Sensitivity 2	$75,315	10.1%	$94,230	10.6%	$257,792	10.8%
Sensitivity 3	$70,315	8.1%	$89,230	9.2%	$247,792	9.6%
Sensitivity 4	$65,315	5.9%	$84,230	7.6%	$237,792	8.3%
Sensitivity 5	$60,315	3.5%	$79,230	6.1%	$227,792	7.0%
Sensitivity 6	$55,315	0.4%	$74,230	4.4%	$217,792	5.6%

The results show that the return on equity increases and declines with net revenue. These figures represent a 20-year levelized net revenue stream and cannot be used to analyze a single year or several years of operation.

Existing and Planned Generation

Installed Capacity and Fuel Mix

During calendar year 2006, PJM installed capacity decreased slightly from 163,027 MW on January 1 to 162,143 MW on December 31, and the fuel mix also shifted slightly. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

Installed Capacity

On January 1, 2006, PJM installed capacity was 163,026.9 MW.[38] (See Table 3-26.) Over the next five months, unit retirements, facility reratings plus import and export shifts changed installed capacity to 163,026.5 MW on May 31, 2006.

38 Percents shown in Table 3-26 and Table 3-27 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 3-26 PJM capacity (By fuel source): January 1, May 31, June 1 and December 31, 2006

	1-Jan-06		31-May-06		1-Jun-06		31-Dec-06	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,279.2	41.3%	66,691.2	40.9%	66,511.2	40.9%	66,532.5	41.0%
Oil	10,816.4	6.6%	10,823.8	6.6%	10,866.2	6.7%	10,718.1	6.6%
Gas	45,954.3	28.2%	46,962.7	28.8%	47,199.8	29.1%	46,963.0	29.0%
Nuclear	31,229.3	19.2%	30,797.3	18.9%	30,058.3	18.5%	30,044.8	18.5%
Solid Waste	662.9	0.4%	661.9	0.4%	661.9	0.4%	719.6	0.4%
Hydroelectric	7,057.1	4.3%	7,057.1	4.3%	7,128.1	4.4%	7,132.3	4.4%
Wind	27.7	0.0%	32.5	0.0%	32.5	0.0%	32.5	0.0%
Total	163,026.9	100.0%	163,026.5	100.0%	162,458.0	100.0%	162,142.8	100.0%

At the beginning of the new planning year on June 1, 2006, installed capacity decreased by 568.5 MW to 162,458.0 MW, a 0.3 percent decrease in total PJM capacity over the May 31 level.

On December 31, 2006, PJM installed capacity was 162,142.8 MW.[39]

Energy Production by Fuel Source

In calendar year 2006, coal and nuclear units generated 91.4 percent of the total electricity, natural gas 5.5 percent, oil 0.3 percent, hydroelectric 2.0 percent, solid waste 0.7 percent and wind 0.1 percent of total generation. (See Table 3-27.)

Table 3-27 PJM generation [By fuel source (GWh)]: Calendar year 2006

	GWh	Percent
Coal	411,581.2	56.8%
Oil	2,029.9	0.3%
Gas	40,044.5	5.5%
Nuclear	250,995.7	34.6%
Solid Waste	4,801.2	0.7%
Hydroelectric	14,684.7	2.0%
Wind	787.9	0.1%
Total	724,925.1	100.0%

39 Wind-based resources accounted for 32.5 MW of installed capacity in PJM on December 31, 2006. This value represents 20 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 20 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using the most recent three years of actual data in place of the 80 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects the market's perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2006, about 49,000 MW of capacity were in generation request queues for construction through 2016, compared to an average installed capacity of 162,571 MW in 2006 and a year-end, installed capacity of about 162,143 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity. (See Table 3-28.)

Table 3-28 Year-to-year capacity additions: Calendar years 2000 to 2006

Year	MW
2000	504
2001	1,068
2002	3,800
2003	3,521
2004	1,925
2005	777
2006	137

A more detailed examination of the queue data reveals some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west. The geographic distribution of units by fuel type in the queues, when combined with data on unit age, suggests that reliance on natural gas as a fuel in the east will increase.

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months. Queue S will be active through July 31, 2007.[40]

Capacity in generation request queues (See Table 3-29.) for the 11-year period beginning in 2006 and ending in 2016 increased by 24,533 MW from 24,428 MW in 2005 to 48,961 MW in 2006.[41, 42] Queued capacity scheduled for service in 2006 decreased from 5,931 MW to 2,689 MW, or 55 percent. Queued capacity scheduled for service in 2007 increased from 5,425 MW to 7,988 MW, or 47 percent. Capacity in the queues for each of the years 2007 through 2010 also increased in 2006 over 2005. Queued capacity scheduled for service in the years 2011 through 2016 indicates that capacity is being planned further in the future than last year. In 2005, no projects were in queues projected to enter service later than 2010.

40 The dates of the RTEP feasibility studies were reported as the end dates of the queues in the *2005 State of the Market Report* instead of the actual start and end dates of the queues. Queue commencement and expiration dates have been changed to reflect the correct dates.

41 See the *2005 State of the Market Report* (March 8, 2006), pp. 138-139, for the queues in 2005.

42 The 48,961 MW includes generation with scheduled in-service dates in 2006 and earlier years net of generation that is in service earlier than scheduled.

Table 3-29 Queue comparison (MW): Calendar years 2006 vs. 2005

	MW in the Queue 2005	MW in the Queue 2006	Year-to-Year Change (MW)	Year-to-Year Change
2006	5,931	2,689	(3,242)	(55%)
2007	5,425	7,988	2,563	47%
2008	6,462	9,705	3,243	50%
2009	1,735	4,575	2,840	164%
2010	4,875	7,436	2,561	53%
2011	0	5,935	5,935	NA
2012	0	4,159	4,159	NA
2013	0	1,600	1,600	NA
2014	0	0	0	NA
2015	0	3,234	3,234	NA
2016	0	1,640	1,640	NA
Total	24,428	48,961	24,533	NA

Table 3-30 shows the amount of capacity currently active, in service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue.[43]

43 Projects listed as active have been entered in the queue and the next phase can be under construction, in service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

Table 3-30 Capacity in PJM queues (MW): At December 31, 2006[44]

Queue	Active	In Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,933	0	18,190	27,123
B Expired 31-Jan-99	0	4,470	0	16,050	20,520
C Expired 31-Jul-99	47	531	0	4,104	4,682
D Expired 31-Jan-00	0	768	0	7,603	8,371
E Expired 31-Jul-00	0	795	0	17,637	18,432
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	670	486	1,125	21,293	23,574
H Expired 31-Jan-02	0	260	443	8,422	9,125
I Expired 31-Jul-02	76	81	0	4,863	5,020
J Expired 31-Jan-03	0	36	155	707	898
K Expired 31-Jul-03	15	124	499	2,068	2,706
L Expired 31-Jan-04	0	66	666	3,558	4,290
M Expired 31-Jul-04	458	96	373	3,662	4,589
N Expired 31-Jan-05	2,413	1,929	159	5,268	9,769
O Expired 31-Jul-05	4,224	248	79	3,339	7,890
P Expired 31-Jan-06	6,417	393	15	2,122	8,947
Q Expired 31-Jul-06	14,224	0	5	1,312	15,541
R Expired 31-Jan-07	14,309	0	0	0	14,309
Total	42,853	19,268	3,519	123,291	188,931

Data presented in Table 3-30 show that 70 percent of total in-service capacity from all the queues was from Queues A and B and an additional 11 percent was from Queues C, D and E.[45]

44 The *2005 State of the Market Report* included only new capacity in the queues. The *2006 State of the Market Report* contains all projects in the queue including reratings of existing generating units and energy only resources.

45 The data for Queue R include projects through December 31, 2006.

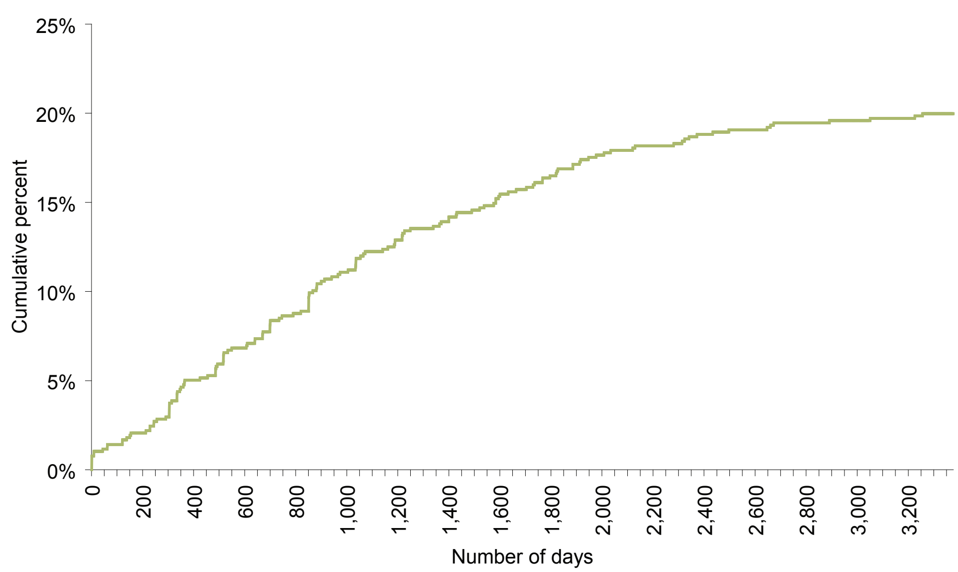
The data presented in Table 3-31 show that for successful projects there is an average time of 1,050 days (2.9 years) between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 933 days (2.6 years) between entering a queue and exiting. For each status, there is substantial variability around the average results.

Table 3-31 Average project queue time: At December 31, 2006

Status	Average (Days)	Standard Deviation	Minimum	Maximum
In Service	1,050	784	0	3,376
Under Construction	1,124	463	333	2,159
Withdrawn	933	735	0	3,376
Active	475	364	152	2,890

Figure 3-3 shows the cumulative probability of completion of RTEP projects. The first queue (Queue A) was opened more than 3,600 days ago and the final active project in the A Queue was completed in 2006. The final project was in the queue for 3,376 days and this is the upper limit of Figure 3-3. The data show that about 15 percent of all projects in the queue are completed within 1,584 days and approximately 20 percent of the projects are completed within 3,376 days.

Figure 3-3 RTEP project completion probability as function of days in queue



Distribution of Units in the Queues

Table 3-32 shows the RTEP projects under construction or active as of December 31, 2006, by unit type and control zone. Most (92 percent of the MW) of the steam projects (predominantly coal) and most of the wind projects (89 percent of the MW) are outside the Eastern MAAC[46] and Southwestern MAAC[47] locational deliverability areas (LDAs).[48] Most (60 percent of the MW) of the combined-cycle (CC) projects are in the Eastern MAAC and Southwestern MAAC LDAs. Wind projects account for approximately 15,607 MW of capacity or 34 percent of the capacity in the queues and combined-cycle projects account for 7,306 MW of capacity or 16 percent of the capacity in the queues.[49] Of the total capacity additions only about 6,500 MW or 14 percent are projected to be in the zones that are in the Eastern MAAC LDA and about 4,600 MW or 10 percent are projected to be constructed in the zones that are in the Southwestern MAAC LDA.

Table 3-32 Capacity additions in active or under-construction queues by zone (MW): At December 31, 2006

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	225	0	4	0	0	650	0	879
AEP	0	27	247	5	84	5,349	1,078	6,790
AP	640	0	11	0	0	2,547	2,078	5,276
BGE	0	10	5	0	3,280	0	0	3,295
ComEd	600	0	104	0	280	765	6,948	8,697
DAY	0	24	0	0	0	0	444	468
Dominion	1,633	0	97	94	1,594	62	0	3,480
DPL	0	0	14	0	0	630	1,749	2,393
JCPL	1,261	20	40	1	0	0	0	1,322
Met-Ed	47	0	37	0	0	0	0	84
PECO	550	20	7	0	140	0	0	717
PENELEC	0	0	0	16	0	310	2,281	2,607
PEPCO	1,250	14	0	0	0	0	0	1,264
PPL	0	0	15	140	218	6,202	1,029	7,604
PSEG	1,100	46	7	0	43	0	0	1,196
UGI	0	0	0	0	0	300	0	300
Total	7,306	161	588	256	5,639	16,815	15,607	46,372

46 The Eastern MAAC LDA consists of the AECO, DPL, PECO, JCPL and PSEG Control Zones.

47 The Southwestern MAAC LDA consists of the BGE and PEPCO Control Zones.

48 See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a PJM LDA map.

49 Since wind resources cannot be dispatched on demand, PJM rules require that the unforced capacity of these resources be derated by 80 percent until actual generation data are available. The derating of 15,600 MW of wind resources means that only 33,900 MW of capacity are effectively in the queue of the 46,400 MW currently active in the queues.

Table 3-33 shows existing generators by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity are distributed across control zones.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources now in the queue (See Table 3-32.) and the location of units likely to retire. In both the Eastern and Southwestern MAAC LDAs, the capacity mix is likely to shift to more natural gas-fired CC and combustion turbine (CT) capacity. In other LDAs, continued reliance on steam (mainly coal) seems likely.

Table 3-33 Existing PJM capacity 2006 [By zone and unit type (MW)]

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	155	528	15	0	0	1,108	8	1,814
AEP	4,133	3,473	0	1,008	2,093	22,735	0	33,442
AP	1,129	1,085	43	80	0	7,862	81	10,280
BGE	0	872	0	0	1,735	2,793	0	5,400
ComEd	1,790	6,232	15	0	11,448	7,194	103	26,782
DAY	0	1,316	54	0	0	3,851	0	5,221
DLCO	272	45	0	0	1,630	1,164	0	3,111
Dominion	2,515	3,226	105	3,321	3,459	8,271	0	20,897
DPL	1,088	764	82	0	0	1,825	0	3,759
External	72	1,223	0	0	0	8,615	0	9,910
JCPL	1,635	1,217	0	400	619	9	0	3,880
Met-Ed	2,043	416	1	17	786	804	0	4,067
PECO	2,407	1,498	8	1,618	4,492	2,022	0	12,045
PENELEC	0	336	44	490	0	6,775	42	7,687
PEPCO	1,134	1,333	0	0	0	4,781	0	7,248
PPL	1,674	613	35	568	2,289	5,832	114	11,125
PSEG	2,581	3,016	15	11	3,353	2,538	0	11,514
Total	22,628	27,193	417	7,513	31,904	88,179	348	178,182

Table 3-34 shows the age of PJM generators by unit type. If the age profile of steam units in PJM accurately represents the future age profile, significant and disproportionate retirements of steam units will occur within the next 10 to 20 years. While steam units comprise 49 percent of all current MW, steam units 40 years of age and older comprise 91 percent of all MW 40 years of age and older and nearly 99 percent of such MW if hydroelectric is excluded from the total. Approximately 6,619 MW of steam units 40 years of age and older are located the Eastern MAAC and Southwestern MAAC LDAs.

Table 3-34 PJM capacity age (MW)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
Less than 10	17,414	17,094	95	119	0	755	348	35,825
10 to 20	4,610	2,950	67	54	6,532	8,532	0	22,745
20 to 30	134	33	52	3,112	13,951	10,616	0	27,898
30 to 40	470	6,959	164	1,505	11,421	39,974	0	60,493
40 to 50	0	157	34	1,415	0	18,065	0	19,671
50 to 60	0	0	4	354	0	10,101	0	10,459
60 to 70	0	0	1	122	0	136	0	259
70 to 80	0	0	0	538	0	0	0	538
80 to 90	0	0	0	135	0	0	0	135
90 to 100	0	0	0	132	0	0	0	132
100 and over	0	0	0	27	0	0	0	27
Total	22,628	27,193	417	7,513	31,904	88,179	348	178,182

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units in the Eastern and Southwestern MAAC LDAs are replaced by units burning natural gas. Table 3-35 shows that in the Eastern MAAC LDA, gas consuming unit types (CC and CT facilities) dominate the capacity additions; however, steam and wind projects are new entrants into the queues this year. Steam additions (coal) account for about 20 percent of the MW and wind projects account for 27 percent of the MW in the queue for the Eastern MAAC LDA. Note that the wind capacity in Table 3-35 is reported at nameplate capacity and not reduced by 80 percent. If it were not for newly queued nuclear capacity in the Southwestern MAAC LDA, gas consuming unit types would also dominate the capacity additions in that LDA.

Table 3-35 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2006

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
Eastern MAAC	3,136	86	72	1	183	1,280	1,749	6,507
Non-MAAC	2,873	51	459	99	1,958	8,723	10,548	24,711
Southwestern MAAC	1,250	24	5	0	3,280	0	0	4,559
Western MAAC	47	0	52	156	218	6,812	3,310	10,595
PJM Total	7,306	161	588	256	5,639	16,815	15,607	46,372

Table 3-36 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2016. Nearly 51 percent of the Eastern MAAC LDA generation would be from CC and CT generators, an increase of 5.5 percentage points from today. Accounting for the fact that about 700 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in the Eastern MAAC LDA from about 37 percent to about 41 percent. This proportion of gas-fired capacity in the Eastern MAAC LDA would increase to 44 percent if the 80 percent reduction for wind capacity is taken into account for the Eastern MAAC LDA, meaning that the effective capacity additions are 5,108 MW.

The exact expected role of gas-fired generation depends heavily on the projects currently in the queues. Two coal projects in the Eastern MAAC LDA totaling 1,280 MW face substantial site-related issues. There is a planned addition of 3,300 MW of nuclear capacity in the Southwestern MAAC LDA.

Without the planned coal-fired capability in the Eastern MAAC LDA, new gas-fired capability would represent 62 percent of all new capability in the Eastern MAAC LDA and 84 percent when the 80 percent reduction for wind capability is included. In 2016 this would mean that combined-cycle and combustion turbine generators would comprise 54.7 percent of total generation in the Eastern MAAC LDA.

Without the planned nuclear capability in the Southwestern MAAC LDA, new gas-fired capability would represent 99.6 percent of all new capability in the Southwestern MAAC LDA. In 2016 this would mean that combined-cycle and combustion turbine generators would comprise 41.3 percent on of total generation in the Southwestern MAAC LDA.

Table 3-36 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2010[50]

Area	UnitType	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators All Ages	Percent of Area Total	Additional Capability through 2016	Estimated Capacity 2016	Percent of Area Total
Eastern MAAC	Combined Cycle	0	0.0%	7,866	23.8%	3,136	11,002	31.0%
	Combustion Turbine	157	3.1%	7,023	21.3%	86	6,952	19.6%
	Diesel	30	0.6%	120	0.4%	72	162	0.5%
	Hydroelectric	948	19.0%	2,029	6.1%	1	2,030	5.7%
	Nuclear	0	0.0%	8,464	25.6%	183	8,647	24.4%
	Steam	3,855	77.3%	7,502	22.7%	1,280	4,927	13.9%
	Wind	0	0.0%	8	0.0%	1,749	1,757	5.0%
	Eastern MAAC Total	4,990	100.0%	33,012	100.0%	6,507	35,477	100.0%
Non-MAAC	Combined Cycle	0	0.0%	9,911	9.0%	2,873	12,784	11.1%
	Combustion Turbine	0	0.0%	16,600	15.1%	51	16,651	14.4%
	Diesel	3	0.0%	217	0.2%	459	673	0.6%
	Hydroelectric	1,338	6.6%	4,409	4.0%	99	4,508	3.9%
	Nuclear	0	0.0%	18,630	17.0%	1,958	20,588	17.9%
	Steam	19,053	93.4%	59,692	54.4%	8,723	49,362	42.8%
	Wind	0	0.0%	184	0.2%	10,548	10,732	9.3%
	Non-MAAC Total	20,394	100.0%	109,643	100.0%	24,711	115,298	100.0%
Southwestern MAAC	Combined Cycle	0	0.0%	1,134	9.0%	1,250	2,384	16.5%
	Combustion Turbine	0	0.0%	2,205	17.4%	24	2,229	15.4%
	Diesel	0	0.0%	0	0.0%	5	5	0.0%
	Hydroelectric	0	0.0%	0	0.0%	0	0	0.0%
	Nuclear	0	0.0%	1,735	13.7%	3,280	5,015	34.7%
	Steam	2,764	100.0%	7,574	59.9%	0	4,810	33.3%
	Wind	0	0.0%	0	0.0%	0	0	0.0%
	Southwestern MAAC Total	2,764	100.0%	12,648	100.0%	4,559	14,443	100.0%
Western MAAC	Combined Cycle	0	0.0%	3,717	16.2%	47	3,764	12.2%
	Combustion Turbine	0	0.0%	1,365	6.0%	0	1,365	4.4%
	Diesel	6	0.2%	80	0.3%	52	126	0.4%
	Hydroelectric	437	14.2%	1,075	4.7%	156	1,231	4.0%
	Nuclear	0	0.0%	3,075	13.4%	218	3,293	10.7%
	Steam	2,630	85.6%	13,411	58.6%	6,812	17,593	57.0%
	Wind	0	0.0%	156	0.7%	3,310	3,466	11.2%
	Western MAAC Total	3,073	100.0%	22,879	100.0%	10,595	30,838	100.0%
All Areas	Total	31,221		178,182		46,372	196,056	

50 Percents shown in Table 3-36 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2006 High-Load Events, Scarcity and Scarcity Pricing Events

In 2005 it was recognized that changing market dynamics created by PJM's expanded footprint, along with PJM's continued need for non market emergency mechanisms to maintain system reliability under conditions of scarcity, had created a need for an administrative scarcity pricing mechanism.[51] PJM entered into a settlement in 2005 that was approved by the FERC and resulted in the implementation of administrative scarcity pricing rules in 2006.[52]

PJM's administrative scarcity pricing mechanism was designed to ensure the appropriate tradeoff between limiting local market power and allowing market prices to reflect scarcity conditions.[53] The administrative rules initiate scarcity pricing when PJM takes specific, non market, emergency administrative actions to maintain system reliability under conditions of high load in prespecified areas within PJM. These emergency actions include: emergency energy purchase request events, maximum emergency generation events, manual load dump events and voltage reduction events. When PJM implements any of the identified emergency procedures, any offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

While PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions, the MMU's review of 2006 market results leads to the recommendation that PJM's scarcity pricing mechanism be reviewed and modified.

Definitions and Methodology

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.[54] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days are likely to be the result of appropriate scarcity pricing rather than market power. 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.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs in well-defined stages with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy

51 See *2005 State of the Market Report,* "Scarcity" (March 8, 2006), pp. 145-150.

52 114 FERC ¶ 61,076 (2006).

53 114 FERC ¶ 61,076 (2006).

54 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."

and capacity markets. With a capacity market design that appropriately reflects scarcity rents in the energy market, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power.

The challenge is to translate these basic guidelines about scarcity into a consistent set of market rules. The MMU analysis of scarcity constitutes the first step toward a comprehensive analysis of scarcity. The MMU recommendations regarding scarcity pricing represent a step towards a set of market rules but work remains to be done.

In order to proceed with the analysis, terms must be carefully defined so that the results can be interpreted and so that the next steps in the analysis can be taken.

A high-load event is defined to exist when hourly demand, including the day-ahead operating reserve target, equals 90 percent or more of total, within-hour supply in the absence of non market administrative intervention.[55, 56]

Scarcity is defined to exist when hourly demand, including the day-ahead operating reserve target, is greater than, or equal to, total, within-hour supply in the absence of non market administrative intervention. Scarcity can exist at varying levels of severity, reflected by the degree to which load plus the reserve requirement exceeds within-hour supply but for non market administrative actions. The more emergency resources needed to maintain system reliability, the more severe the scarcity event.

Within-hour, economic (non-emergency) resources include loaded generation, the lesser of the hourly available ramp or remaining non-emergency capacity of synchronized resources, the lesser of hourly available ramp or available non-emergency capacity of non-synchronized resources with less than a one-hour start-up time.[57] All within-hour, available generation values reflect available outage information.

The total system hourly operating reserve target is calculated based on the sum of the control-zone-specific, 30-minute, day-ahead reserve requirements as defined by PJM.[58] The definitions of high-load and scarcity events do not account for potential violations of aggregate or zone-specific, 10-minute primary reserve requirements or 30-minute operating reserve targets. Nonetheless, the net within-hour resource calculation provides a reasonable measure of overall system high-load conditions. The basis of the zone-specific reserve requirements is shown in Table 3-37.

55 Load, as used here, is based on hourly eMTR loads in each hour, which is the simple average of the 12 five-minute interval loads in the hour for the total system.

56 See PJM "Manual 10: Pre-Scheduling Operations," Revision 20 (Effective June 15, 2006), pp. 21-25; and PJM "Manual 11: Scheduling Operations," Revision 29 (Effective August 11, 2006), pp. 87-96.

57 The methodology used to determine within-hour resources for this analysis tends to overestimate within-hour resources. For example, a unit's total within-hour ramp is presumed available from the first five-minute interval to the last, rather than being limited to the actual five-minute ramp rate within the hour. This means that a unit with a 100 MW ramp (with 100 MW capacity) is assumed to provide an average of 100 MW every minute of the hour. This methodology also overestimates available resources relative to the primary reserve requirement, as primary reserve resources must be available on less than a 30-minute basis. This measure also ignores transmission constraints that may limit deliverability to meet local load.

58 See PJM "Manual 10: Pre-Scheduling Operations," Revision 20 (Effective June 15, 2006), pp. 21-25; and PJM "Manual 11: Scheduling Operations," Revision 29 (Effective August 11, 2006), pp. 87-96.

Table 3-37 Zone-specific operating reserve targets and requirements[59]

Control Zone	Region	Operating (Day Ahead)	Primary (Real Time)	Synchronized Reserve	Regulation
PJM	Mid-Atlantic	Load Dependent	1,700 MW	Largest Unit	1% Peak
AP	Western	6% Forecast Load	3% Forecast Load	1.5% Peak Load	1% Peak
AEP	Western	6% Forecast Load	3% Forecast Load	1.5% Peak Load	1% Peak
DAY	Western	6% Forecast Load	3% Forecast Load	1.5% Peak Load	1% Peak
ComEd	Western	MAIN ARS + Regulation	MAIN ARS	50% MAIN ARS	1% Peak
Dominion	Southern	6% Forecast Load	VACAR ARS%	VACAR ARS%	1% Peak
DLCO	Western	6% Forecast Load	3% Forecast Load	1.5% Peak Load	1% Peak

Non market administrative tools available to PJM to ensure the convergence of supply and demand include active load management (ALM), capacity recalls of noncapacity-backed exports, load reduction action (Emergency Load-Response Program), the loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dump.[60] Of these steps, the last four (the loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dump) are defined in the PJM Tariff as triggers for scarcity pricing events.[61]

Any non market administrative tools used by PJM in a given hour are used to adjust the measures of supply and demand to calculate the net supply condition that would have existed absent PJM intervention. For example, PJM-called ALM, which reduces load, would be added to total demand for determination of within-hour net resources. PJM-called ALM in 2006 is shown in Table 3-38. In the event that maximum emergency generation was loaded at PJM direction, the value of the hourly maximum emergency generation loaded would be subtracted from PJM total within-hour, non-emergency supply for the determination of net within-hour, available non-emergency resources. When a maximum emergency alert is declared and the maximum emergency capacity is counted towards operating reserve targets, the added capacity is considered to be non-economic for purposes of this analysis. Maximum emergency generation alerts were declared in one or more zones on July 17, through July 18, July 31, and August 1, through August 3, 2006. On those same dates, available maximum emergency capacity was counted towards operating reserve targets.

Table 3-38 PJM-called ALM: August 2 and August 3, 2006

	02-Aug-06		03-Aug-06	
	Start	Stop	Start	Stop
Short lead time ALM called (Mid-Atlantic)	15:30	19:30	13:00	19:00
Long lead time ALM called (Mid-Atlantic)	13:00	19:00	12:15	19:00

59 See PJM "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 12. ARS is automatic reserve sharing.

60 See PJM "Manual 13: Emergency Operations," Revision: 27 (Effective September 5, 2006), p. 29: "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain reliability."

61 See PJM Open Access Transmission Tariff (OATT), Sixth Revised Volume No. 1, Third Revised Sheet No. 402A.01 (Effective January 27, 2006).

2006 Results: High Load and Scarcity Hours

As defined above, there were 70 hours of high load that occurred. Of those 70 hours, 17 high-load hours occurred from July 17 through July 19; 51 high-load hours occurred from July 31 through August 3 and two high-load hours occurred on August 7.[62] Within these 70 hours, there were 10 hours on August 1 and August 2 that met the criteria for potential within-hour scarcity, as defined above.[63]

Figure 3-4 shows the hourly loads of each of the eight high-load days relative to the average hourly summer load for 2006. August 2 had the highest coincident-peak load of the summer, followed closely by August 1.

Figure 3-4 High-load day hourly load and average hourly load: Summer 2006

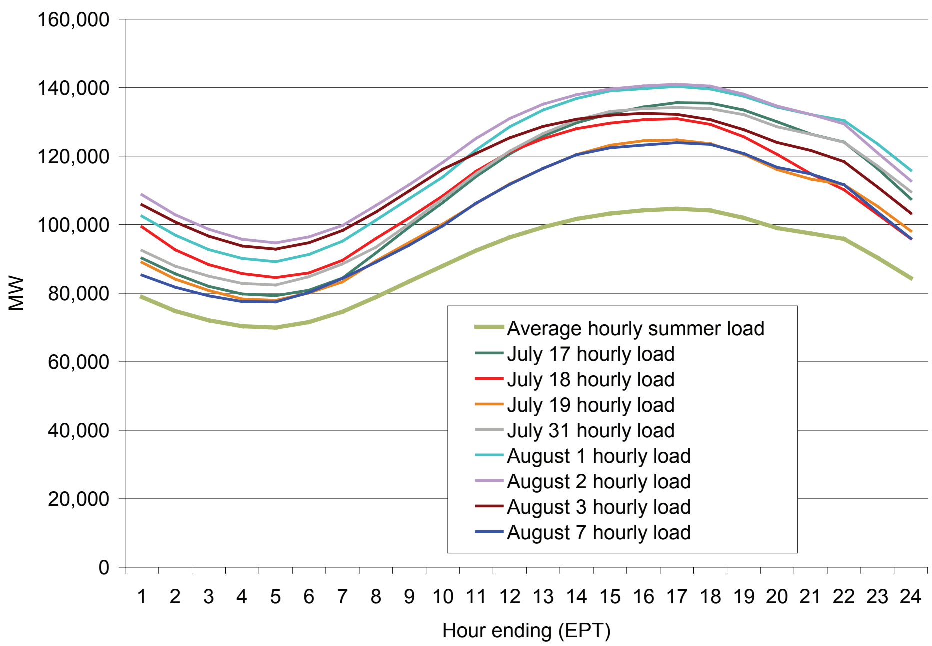


Figure 3-5 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand including the day-ahead operating reserve target for July 17 through July 19, and July 31, 2006.[64, 65] Figure 3-6 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand including the day-ahead operating reserve requirement for August 1 through August 3, and August 7, 2006. In both figures, hours that meet the high-load definition are indicated by yellow bars, hours that meet the scarcity definition are indicated by red bars and all other hours are indicated by green bars.

62 A high-load event is defined as a period during which real-time system load, plus the total of the system day-ahead operating reserve target, approaches a level that, in the absence of non market administrative intervention by the RTO or transmission zone, requires the use of 90 percent or more of total within-hour, available non-emergency resources in one or more hours in a given 24-hour period.

63 Scarcity is considered to exist when hourly demand, including a total operating reserve requirement, is greater than, or equal to, total, within-hour supply in the absence of non market administrative intervention.

64 Load, as used here, is based on hourly eMTR loads in each hour, which are the simple average of the 12 five-minute interval loads in the hour for the total system.

65 See PJM "Manual 10: Pre-Scheduling Operations," Revision 20 (Effective June 15, 2006), pp. 21-25; and PJM "Manual 11: Scheduling Operations," Revision 29 (Effective August 11, 2006), pp. 87-96.

PJM took emergency action or made use of emergency resources on the days identified as including high load and scarcity hours. PJM operations declared maximum emergency generation alerts for July 17 through July 18, and July 31, through August 3, 2006, for one or more zones. During this period available maximum emergency capacity was included in the calculation of operating reserve by PJM. Absent the inclusion of this capacity, PJM would have missed its day-ahead operating reserve target in one or more control zones for one or more hours in each of the days listed. PJM operations recorded primary reserve warnings in one or more zones on July 18, August 2, and August 3, 2006.

Figure 3-5 Net within-hour resources: July 17 to July 19, and July 31, 2006

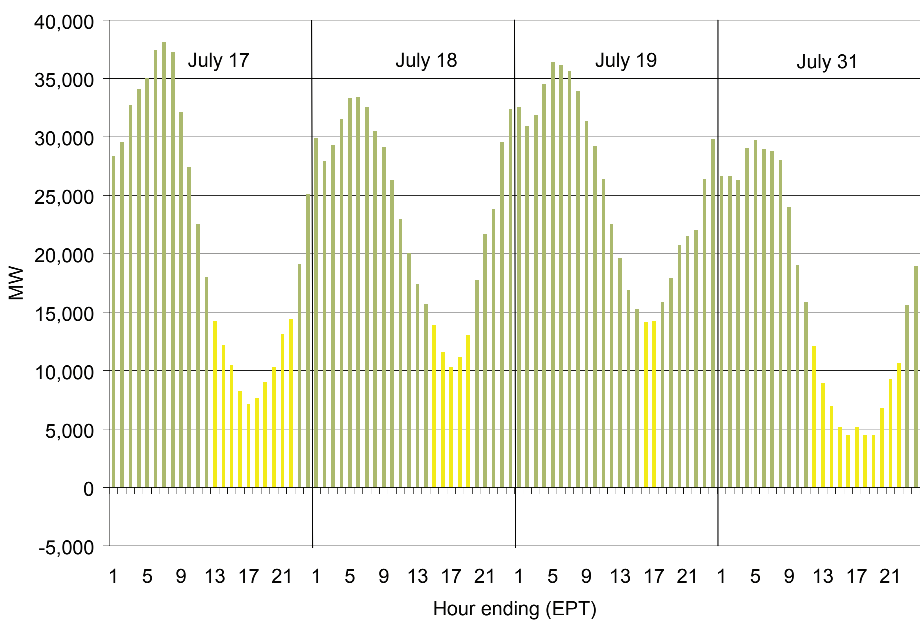


Figure 3-6 Net within-hour resources: August 1 to August 3, and August 7, 2006

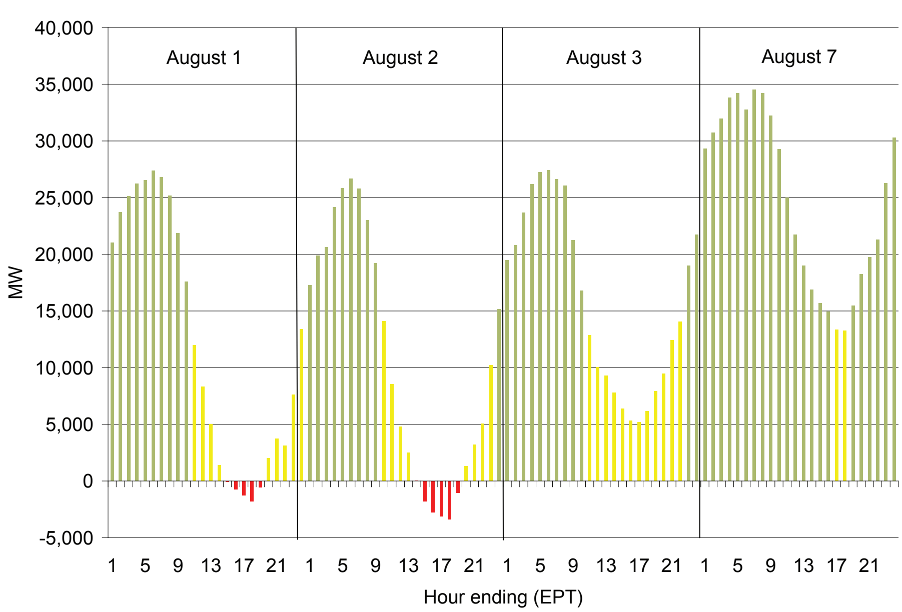
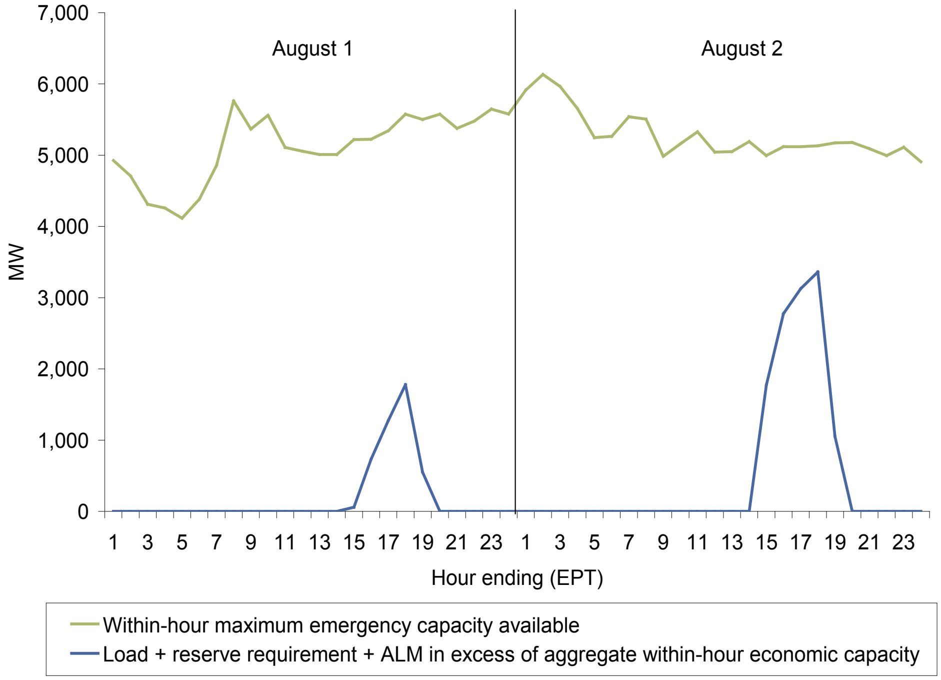


Figure 3-7 shows the within-hour, available maximum emergency generation capacity, by hour and total hourly demand in excess of total within-hour economic supply for August 1 and August 2. On August 1 and August 2, on an hourly aggregate basis, total demand, including the day-ahead operating reserve target and ALM taken, caused PJM to be in a scarcity condition, as defined here.

Figure 3-7 Within-hour maximum emergency capacity relative to hourly demand in excess of within-hour economic resources: August 1 to August 2, 2006



Maximum emergency generation is generation capacity that PJM considers to be above the maximum economic level.[66] In concept, maximum emergency generation should represent temporary MW additions to capacity made possible by operating a generator above its maximum economic capacity. In practice, the definition of maximum emergency generation in PJM is unclear and has been expanded beyond this scope to include environmental, fuel, temporary emergency conditions at the unit and other conditions which are declared to limit the availability of all or a portion of a unit's capacity. However, according to the PJM Tariff, during maximum emergency generation alerts the only capacity that can be designated as maximum emergency must fall into one of the following categories:

- **Environmental Limits.** If the unit has a hard cap on its run hours imposed by an environmental regulator that will temporarily significantly limit its availability.

- **Fuel Limits.** If physical events beyond the control of the unit owner result in the temporary interruption of fuel supply and there is limited onsite fuel storage, a fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the unit owner.

66 See PJM "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 34.

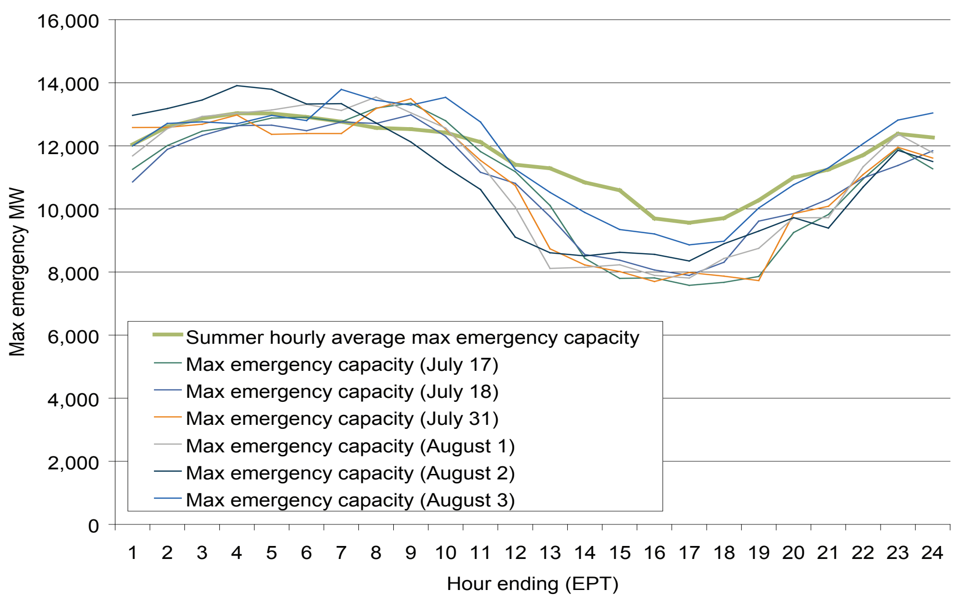
- **Temporary Emergency Conditions at the Unit.** If temporary emergency physical conditions at the unit significantly limit its availability.

- **Temporary MW Additions.** If a unit can provide additional MW on a temporary basis by oil topping, boiler overpressure, or similar techniques and such MW are not ordinarily otherwise available.[67]

In the event of a declaration of a maximum emergency generation alert, generation owners are required, within PJM-specified time frames, to re-designate any maximum emergency capacity that does not meet the above criteria as economic capacity.[68]

Figure 3-8 shows the hourly comparison of declared maximum emergency capacity on days when maximum emergency generation alerts had been issued by the RTO in one or more zones. On average, the capacity declared as maximum emergency generation capacity fell, consistent with the scarcity rules, during the high-load period of each day, relative to the summer average in each hour.

Figure 3-8 Comparison of hourly maximum emergency capacity on maximum generation alert days to the hourly summer average maximum emergency capacity: Summer 2006



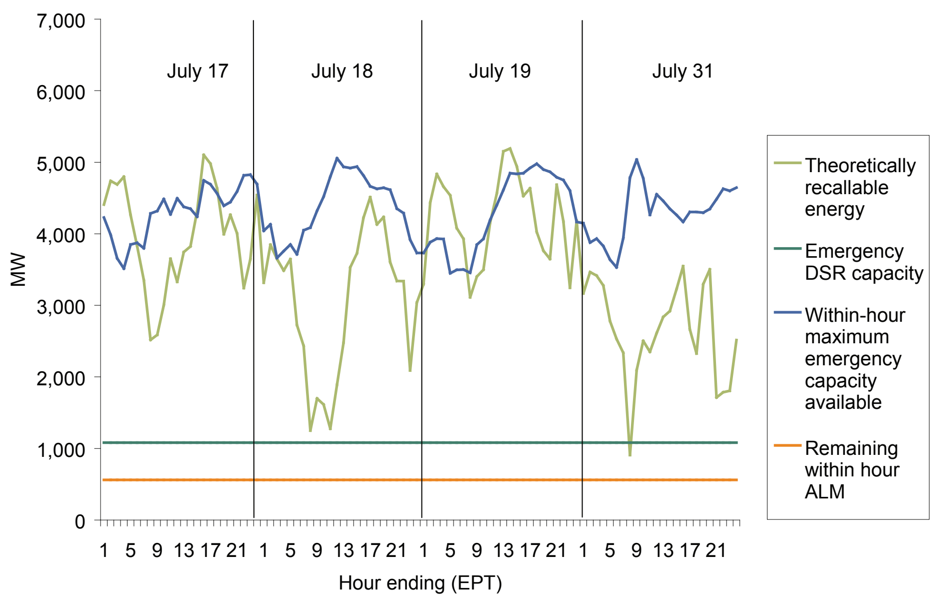
With the exception of potential emergency energy purchases and voltage reduction effects, Figure 3-9 shows each hour's within-hour available emergency resources for July 17 through July 19 and July 31.

67 See PJM "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), pp. 73-74.

68 See PJM "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 74: "On days when PJM has declared, prior to 1800 hours on the day prior to the operating day, a Maximum Emergency Generation Alert for the entire PJM Control Area or for specific Control Zones or Scarcity Pricing Regions, the only units for which all of part of their capability may be designated as Maximum Emergency are those that meet the criteria described above. Should PJM declare a Maximum Generation Alert during the operating day for which the alert is effective, generation owners will be responsible for removing any unit availability from the Maximum Generation category that does not meet the above criteria within 4 hours of the issuance of the alert. PJM will make a mechanism available to participants by which they may inform PJM of their generating capability that meets the above criteria and indicate which of the criteria it meets."

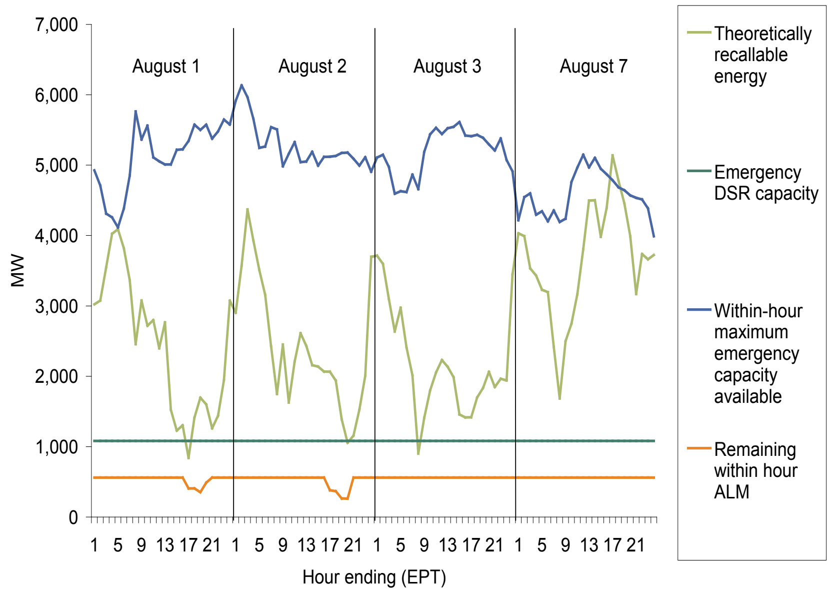
Figure 3-10 shows each hour's within-hour available emergency resources for August 1, through August 3, and August 7, 2006. The figures provide estimates of hourly recallable energy, registered emergency DSR, within-hour available maximum emergency capacity and net remaining short-notification ALM. Maximum emergency capacity available includes the lesser of the hourly available ramp or remaining emergency capacity on synchronized resources and the lesser of hourly available ramp or available capacity of non-synchronized, maximum emergency-only resources with less than a one-hour start-up time.[69] For purposes of determining the amount of energy available for emergency recall in a particular hour, total generation from delisted units is subtracted from exports in each hour. The result is a measure of recallable, export MW from PJM capacity resources. This value is likely to be significantly larger than the total energy that could actually be recalled in an emergency. During times of significantly high load on a regional scale, if PJM operators believe that recalling energy could trigger reciprocal recalls from neighboring RTOs and control areas which could make the system harder, not easier, to manage, they will likely not recall the energy. All within-hour available generation values reflect available outage information. On the days in question, the most significant potential source of non-economic capacity was available within-hour maximum emergency generation.

Figure 3-9 Within hour emergency resources: July 17 to July 19, and July 31, 2006



69 The methodology used to determine within-hour resources for this analysis tends to overestimate within-hour resources. For example, a unit's total within-hour ramp is presumed available from the first five-minute interval to the last, rather than being limited to the actual five-minute ramp rate within the hour. This means that a unit with a 100 MW ramp (with 100 MW capacity) is assumed to provide an average of 100 MW every minute of the hour. This methodology also overestimates available resources relative to the primary reserve requirement as primary reserve resources must be available on less than a 30-minute basis.

Figure 3-10 Within-hour emergency resources: August 1 to August 3, and August 7, 2006



2006 Scarcity Pricing Events

Four emergency messages trigger administrative scarcity pricing under the PJM Tariff. (See Table 3-39.)[70, 71]

Based on these triggers for scarcity pricing, there were no scarcity pricing events in 2006, despite record loads recorded across the PJM footprint and within specific zones.

Table 3-39 Scarcity-related emergency messages

Emergency Message	Description
Max Emergency Gen Loaded	The purpose is to increase generation above the normal economic limit.
Voltage Reduction	A request to reduce distribution level voltage by 5%, which provides load relief.
Emergency Energy Purchase	This is a request by PJM for emergency purchases of energy. PJM will select which offers are accepted based on price and expected duration of the need. This request is typically issued at the Max Emergency Generation emergency procedure step.
Manual Load Dump	The request to disconnect firm customer load (rotating blackouts). This is issued when additional load relief is needed and all other possible procedures have been exhausted. Target: Electric Distribution Companies

70 “Maximum emergency generation loaded” covers the first three trigger events: a) Begin to dispatch online generators, which are partially designated as maximum emergency, into emergency output levels; b) Begin to dispatch online generators, which are designated entirely as maximum emergency, above their designated minimum load points, if they are currently online and operating at their minimum load points because of restrictive operating parameters associated with the generators; and c) Begin to dispatch any offline generators that are designated entirely as maximum emergency and that have start times plus notification times less than or equal to 30 minutes.

71 114 FERC ¶ 61,076 (2006).

Current Issues with Scarcity Implementation

While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, there are indications, based on the MMU analysis of 2006 market results, that PJM's current set of scarcity pricing rules need refinement.

Although there were identified hours during which supply was less than, or equal to, demand including a day-ahead target level of operating reserve, PJM did not use the specific emergency measures which would have triggered administrative scarcity pricing. PJM was able, via the discretion it is afforded under PJM's Tariff and operating manuals, to use emergency resources to meet operational goals, most notably declaring a maximum emergency alert, which results in the inclusion of maximum emergency generation resources in operational reserve and the calling of ALM resources.

Thus, despite the fact that the demand for power in PJM was very close to the generating capability of the system, prices remained relatively low. This suggests that the definition of scarcity should include several steps or stages of scarcity, each with an associated administrative price, rather than the single step now in the Tariff.

In addition, the actual administrative market signal needs further refinement. Under the current rules, a scarcity pricing event will set prices for all generators in the defined area at the same level, equal to the highest accepted offer within a scarcity pricing region. This provides a signal that is inconsistent with economic dispatch and inconsistent with locational pricing.

The MMU recommends that the current scarcity rule, as provided in the PJM Tariff, be reviewed and enhanced to ensure competitive prices by introducing:

- **Stages of Scarcity Pricing.** Administrative scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. The price levels should be predetermined and applied administratively. The trigger for each stage would be the progressive use of stronger emergency measures. For example, stages of scarcity pricing could be triggered by the calling of a maximum emergency generation alert that allows maximum emergency capacity to be counted towards operating reserve requirements, the calling of ALM, the recall of noncapacity-backed exports, the use of load reduction action (Emergency DSR), the loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dumps in one or more contiguous transmission zones.

- **Locational Price Signals.** The single scarcity price signal should be replaced by locational signals. Adders to all unit offers within the affected zones could allow LMP to continue to provide locational economic signals consistent with least-cost dispatch.

Operating Reserve

Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

If a unit is selected to operate in the PJM Day-Ahead Energy Market but the market revenues for the entire day resulting from that operation are insufficient to cover all offer components, including startup and no-load, then day-ahead operating reserve credits ensure that all offer components are covered.[72] If a generator, scheduled to operate in the Real-Time Energy Market, operates as directed by PJM dispatchers but the market revenues for the entire day resulting from that operation are insufficient to cover all offer components, then balancing operating reserve credits ensure that all offer components are covered.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters as well as the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The level of operating reserve charges declined substantially in 2006 compared to 2005, in significant part as a result of PJM actions to focus attention on PJM decisions that affected the level of operating reserve charges. In particular, PJM created internal processes to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.[73]

The PJM Reserve Market Working Group developed a series of potential steps designed to enhance the efficiency of the operating reserve process and may take action in 2007. Some modifications to PJM rules governing operating reserve credits to generators would be appropriate. Such modifications should aim to ensure that credits paid to market participants and corresponding charges paid by market participants are consistent with incentives for efficient market outcomes and to eliminate gaming incentives and the ability to exercise market power. Such modifications should address both the level of and the appropriate allocation of operating reserve charges, accounting where appropriate and possible for causal factors including location.

72 Operating reserve credits are also provided for pool-scheduled energy transactions, for generating units operating as condensers not as synchronized reserve, for the cancellation of pool-scheduled resources, for units backed down for reliability reasons, for units performing black start tests and for units providing quick start reserve.

73 See Robert O. Hinkel, general manager, PJM Regional Operations, "180 Day Stakeholder Group Operations Process Improvements" (October 24, 2006).

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-40 shows the categories of credits and charges and their relationship.

Table 3-40 Operating reserve credits and charges

Credits	Charges		
Day-Ahead:			
Day-Ahead Energy Market	Day-Ahead Demand		
Day-Ahead Congestion	Decrement Bids		
Day-Ahead Import Transactions	Day-Ahead Export Transactions		
Synchronous Condensing	Real-Time Load		
	Real-Time Export Transactions		
Balancing :			
Balancing Energy Market	Real-Time Deviations		
Balancing Congestion	from Day-Ahead Schedules:		
Lost Opportunity Cost			
Real-Time Import Transactions			
		Net Deviations	
	Day-Ahead		**Real-Time**
	Day-Ahead Decrement Bids	**Demand**	Real-Time Load
	Day-Ahead Load		Real-Time Sales
	Day-Ahead Sales		Real-Time Export Transactions
	Day-Ahead Export Transactions		
	Day-Ahead Increment Offers	**Supply**	Real-Time Purchases
	Day-Ahead Purchases		Real-Time Import Transactions
	Day-Ahead Import Transactions		
	Day-Ahead Scheduled Generation	**Generator**	Real-Time Generation

Day-Ahead Credits and Charges

Day-ahead operating reserve credits consist of day-ahead energy market, day-ahead congestion and day-ahead import transaction credits.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-42 shows monthly day-ahead operating reserve charges for calendar years 2005 and 2006.

Synchronous Condensing Credits and Charges

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy use costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services.

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-42 shows monthly synchronous condensing charges for calendar years 2005 and 2006.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing energy market credits, balancing congestion credits, lost opportunity cost credits and real-time import transaction credits.[74] Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced by PJM for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if market revenues are less than the offer. Balancing operating reserve credits are also paid to canceled, pool-scheduled resources, to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

The operating reserve charges that result from paying balancing operating reserve credits are allocated daily to PJM members in proportion to their real-time hourly deviations from cleared quantities in the Day-Ahead Market. Table 3-42 shows monthly balancing operating reserve charges for calendar years 2005 and 2006. These deviations fall into three categories and are calculated on an hourly net basis: demand, supply and generator deviations. Each type of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between (1) the sum of cleared decrement bids plus cleared, day-ahead load plus day-ahead exports scheduled

74 PJM settlements do not differentiate balancing congestion credits and balancing energy market credits. Balancing congestion credits are defined here as operating reserve credits paid to units that were operated for a transmission constraint in the Real-Time Market or selected for a transmission constraint in the Day-Ahead Market. Balancing energy market credits are what remain in the balancing operating reserve credit category after accounting for credits for balancing congestion, real-time transactions and lost opportunity cost.

through the Enhanced Energy Scheduler (EES)[75] and (2) the sum of real-time load, plus real-time sales scheduled through eSchedules[76] plus real-time exports scheduled through the EES.

- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: (1) the sum of the cleared increment offers plus day-ahead imports scheduled through EES; and (2) the sum of the real-time bilateral transactions scheduled through eSchedules plus real-time imports schedule through EES.

- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between (1) a unit's cleared, day-ahead generation and (2) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour.

Credit and Charge Results

Overall Results

Table 3-41 shows total operating reserve credits from 1999 through 2006, a period when significant market changes occurred.[77, 78] Total operating reserve credits declined by 52.8 percent in 2006.

Table 3-41 also shows the ratio of total operating reserve credits to the total value of PJM market billings.[79] This ratio decreased from 3.0 percent in 2005 to 1.5 percent in 2006. Over the last eight years, this ratio ranged from a low of 1.5 percent in 2006 to a high of 9.6 percent in 2000.

75 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

76 PJM's eSchedules is an application used by participants for internal bilateral transactions.

77 Table 3-41 includes all categories of credits as defined in Table 3-40 and includes all PJM settlements' billing adjustments. Only the energy market credits were reported in the *2005 State of the Market Report.*

78 An Energy Market that clears based on market-based generator offers was initiated on April 1, 1999. The 1999 total includes energy market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the Balancing Energy Market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing services.

79 See *2006 State of the Market Report,* Volume II, Section 7, "Congestion," at Table 7-2, "Total annual PJM congestion [Dollars (millions)]: Calendar years 2002 to 2006," for a description of the value of total annual PJM market billings during the period indicated.

Table 3-41[80] Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2006

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as Percent of Total Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	$0.341	NA	$0.535	NA
2001	$290,867,269	34.0%	8.7%	$0.275	(19.5%)	$1.070	100.2%
2002	$237,102,574	(18.5%)	5.0%	$0.164	(40.4%)	$0.787	(26.4%)
2003	$289,510,257	22.1%	4.2%	$0.226	38.2%	$1.197	52.0%
2004	$414,891,790	43.3%	4.8%	$0.230	1.7%	$1.236	3.3%
2005	$682,781,889	64.6%	3.0%	$0.076	(66.9%)	$2.758	123.1%
2006	$322,315,152	(52.8%)	1.5%	$0.078	2.6%	$1.331	(51.7%)

Finally, Table 3-41 shows the total operating reserve credits per MWh for each full year since the introduction of the Day-Ahead Energy Market.[81] The day-ahead operating reserve rate increased $0.002 per MWh or 2.6 percent from $0.076 per MWh in 2005 to $0.078 per MWh in 2006. The balancing operating reserve rate decreased $1.427 per MWh, or 51.7 percent, from $2.758 per MWh in 2005 to $1.331 per MWh in 2006.

80 Calculated values shown in Table 3-41, Table 3-44, Table 3-45, Table 3-46 and Table 3-47 are based on unrounded underlying data and may differ from calculations based on the rounded values in the tables.

81 In Table 3-41, "Total day-ahead and balancing operating reserve charges" numbers are based on PJM market settlements' data that include manual adjustments. The data in Table 3-42, Table 3-44, Table 3-48 and Figure 3-12 are based on the PJM market settlements' database and do not include manual adjustments.

Table 3-42 compares monthly operating reserve charges by category for calendar years 2005 and 2006. While total operating reserve charges decreased, the level of day-ahead operating reserve charges increased by 6.51 percent between 2005 and 2006 and their share of total operating reserve charges increased from 8.98 percent to 20.31 percent. Synchronous condensing operating reserve charges decreased by 43.24 percent between 2005 and 2006. Balancing operating reserve charges decreased by 59.39 percent between 2005 and 2006 and their share of total operating reserve charges decreased from 87.42 percent to 75.36 percent.

Table 3-42 Monthly operating reserve charges: Calendar years 2005 and 2006

	2005			2006		
	Day Ahead	Synchronous Condensing	Balancing	Day Ahead	Synchronous Condensing	Balancing
Jan	$9,567,053	$4,424,843	$37,895,417	$7,145,655	$511,823	$16,216,936
Feb	$3,358,460	$1,720,120	$18,965,471	$4,525,771	$241,598	$14,107,994
Mar	$3,116,002	$1,289,212	$15,360,115	$4,924,985	$346,133	$7,992,131
Apr	$2,847,685	$1,097,556	$12,110,506	$5,368,796	$156,352	$7,575,039
May	$7,582,892	$242,506	$14,646,225	$6,129,196	$492,418	$11,837,289
Jun	$3,043,378	$2,379,770	$58,066,579	$4,383,153	$983,353	$18,003,134
Jul	$2,672,044	$2,680,880	$99,637,963	$4,838,992	$2,073,350	$43,756,738
Aug	$2,202,173	$3,609,806	$81,020,542	$5,045,827	$2,364,265	$49,491,691
Sep	$3,035,763	$2,530,569	$76,143,552	$6,765,877	$938,744	$14,273,544
Oct	$5,339,286	$2,141,759	$96,352,636	$5,244,729	$1,654,702	$12,890,522
Nov	$5,493,441	$979,360	$32,242,377	$4,191,905	$882,426	$16,465,964
Dec	$11,356,498	$751,026	$37,809,385	$4,929,665	$2,890,772	$23,017,897
Total	$59,614,675	$23,847,407	$580,250,768	$63,494,551	$13,535,936	$235,628,879
Share of Annual Charges	8.98%	3.59%	87.42%	20.31%	4.33%	75.36%

Deviations

Real-time deviations from day-ahead schedules are used to allocate balancing operating reserve charges and are the denominator in the balancing operating reserve rate calculation. Table 3-43 shows monthly real-time deviations for demand, supply and generator categories for 2005 and 2006. From 2005 to 2006, the share of total deviations in the demand category increased by 4.5 percentage points, in the supply category fell by 5.6 percentage points and in the generator category increased by 1.2 percentage points.

Total deviations in 2006 were less than total 2005 levels for all months except November.

Table 3-43 Monthly balancing operating reserve deviations (MWh): Calendar years 2005 and 2006

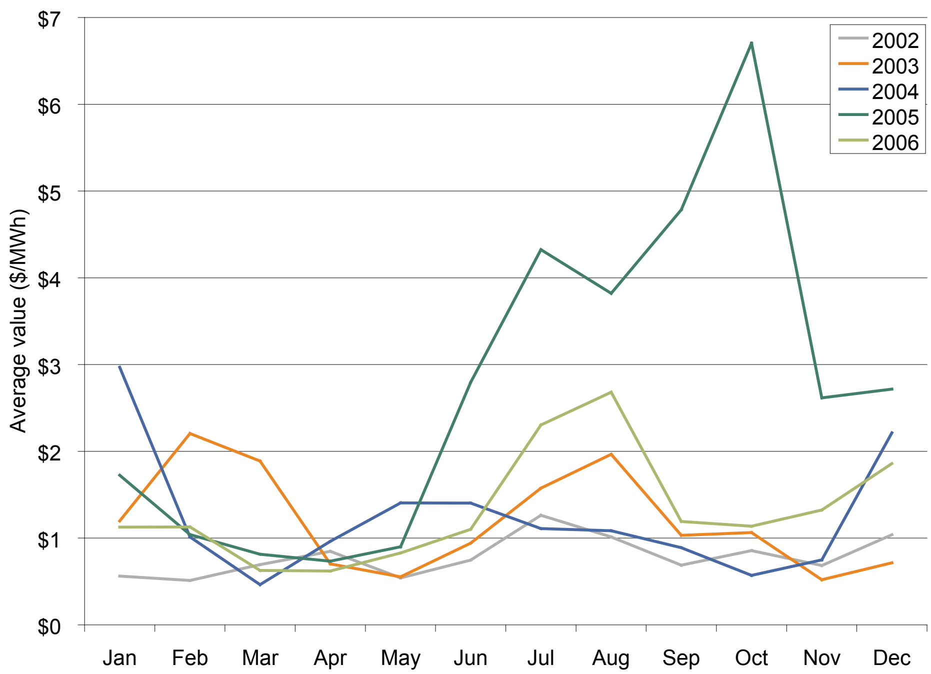
	2005			2006		
	Demand	Supply	Generator	Demand	Supply	Generator
Jan	11,851,254	6,717,597	3,144,258	8,079,917	3,042,526	3,104,765
Feb	9,505,119	5,366,922	3,241,208	7,407,652	2,376,136	2,785,690
Mar	10,367,348	5,198,926	3,637,017	7,782,094	2,440,601	2,579,638
Apr	8,522,724	4,867,238	3,120,261	7,380,697	2,092,666	2,676,689
May	9,280,079	3,893,888	3,395,250	7,732,120	2,476,951	2,700,348
Jun	11,394,615	4,863,249	4,121,267	9,292,155	2,621,207	3,260,040
Jul	13,110,625	5,485,019	4,191,367	11,166,560	3,799,713	3,241,283
Aug	12,021,176	4,702,635	3,783,214	10,639,107	3,321,580	2,879,367
Sep	9,155,776	3,770,614	3,187,321	7,589,892	2,180,845	2,212,283
Oct	7,745,326	3,216,032	2,776,153	6,525,296	2,653,620	2,035,454
Nov	6,971,279	2,822,426	2,343,019	7,228,329	2,685,786	2,379,014
Dec	7,951,859	2,897,055	2,627,646	6,964,809	2,550,484	2,403,937
Total	117,877,180	53,801,601	39,567,981	97,788,628	32,242,115	32,258,508
Share of Annual Deviations	55.80%	25.47%	18.73%	60.26%	19.87%	19.88%

Balancing Operating Reserve Rate

The balancing operating reserve rate equals the total daily amount of balancing operating reserve credits divided by total daily deviations. It is calculated daily. Figure 3-11 shows monthly average balancing operating reserve rates for the past five years. A large increase in the monthly average balancing operating reserve rate occurred between June and October 2005. In 2006, the monthly average balancing operating reserve rate decreased to an average of $1.33 per MW, which was lower than 2005 but higher than any prior year.

The reasons for the observed decrease in the balancing operating reserve charges included decreased fuel costs and improved operating practices by PJM.

Figure 3-11 Monthly average balancing operating reserve rate: Calendar years 2002 to 2006



Characteristics of Credits and Charges

Types of Units

Table 3-44 shows the proportion of total PJM installed capacity by unit type that received balancing operating reserve payments, the proportion of total MW capacity that received balancing operating reserve by unit type and the proportion of balancing operating reserve credits received by unit type.[82] In 2006, CT units received 57.58 percent of balancing operating reserve credits although they represented 20.59 percent of the capacity that received such credits and CTs that received balancing operating reserve credits represented 16.19 percent of total, PJM installed capacity. Steam units received 18.98 percent of balancing operating

82 In Table 3-44 balancing operating reserve credits include balancing congestion, balancing energy and lost opportunity cost credits.

reserve credits, but represented 60.50 percent of the capacity that received such credits and steam units that received balancing operating reserve credits represented 47.57 percent of total, PJM 2006 installed capacity. In 2006, units that received balancing operating reserve credits represented 78.62 percent of total installed PJM capacity.[83] In 2005, units that received balancing operating reserve credits represented 84.28 percent of total installed PJM capacity.[84]

Table 3-44 Installed capacity percentage (By unit type): Calendar years 2005 and 2006

	2005			2006		
	Share of Total PJM Capacity	Share of Capacity Receiving Operating Reserve Credits	Share of Balancing Operating Reserve Credits	Share of Total PJM Capacity	Share of Capacity Receiving Operating Reserve Credits	Share of Balancing Operating Reserve Credits
CC	12.42%	14.74%	24.20%	12.49%	15.89%	21.91%
CT	16.96%	20.12%	51.04%	16.19%	20.59%	57.58%
Diesel	0.15%	0.18%	0.53%	0.20%	0.26%	1.50%
Hydroelectric	NA	NA	NA	0.01%	0.01%	0.00%
Nuclear	4.87%	5.78%	0.27%	2.16%	2.75%	0.03%
Steam	49.88%	59.18%	23.97%	47.57%	60.50%	18.98%
Total	84.28%	100.00%	100.00%	78.62%	100.00%	100.00%

Economic and Non-Economic Generation

Economic generation includes units producing energy at an offer price less than, or equal, to LMP. Non-economic generation includes units that are producing energy but at a higher offer price than the LMP. Non-economic generation includes units assigned by PJM to run and units not assigned by PJM to run or to provide regulation. Regulation generation includes units assigned by PJM to provide regulation. The level of non-economic generation is an indicator of the level of generation that may require operating reserve credits. However, the data are hourly and some generation that is non-economic for an hour may receive adequate market revenues during other hours to offset any shortfall.[85]

83 The value of total PJM installed capacity used for these calculations was based on the amount recorded on December 31, 2006.

84 The results for 2005 in Table 3-44 differ from those reported in the *2005 State of the Market Report*, Section 3, "Energy Market, Part 2," Table 3-29 "Installed capacity percentage (By unit type):Calendar year 2005." The results in the *2006 State of the Market Report* are correct.

85 Self-scheduled units were not included in either economic or non-economic categories. Self-scheduled units are those units which indicate to PJM that they are self-scheduled. Units which are operating, but are not assigned by PJM to run and are not self-scheduled, are non-economic.

Table 3-45 shows the percentage of total PJM self-scheduled generation, economic generation, non-economic generation and regulation generation for 2006.

Table 3-45 PJM self-scheduled, economic, non-economic and regulation generation: Calendar year 2006

	All Hours	On Peak	Off Peak
Self-Scheduled Generation	48.55%	47.40%	51.27%
Economic Generation	44.50%	48.38%	35.31%
Non-Economic Generation	5.41%	3.57%	9.79%
Regulation Generation	1.54%	0.66%	3.63%
Total	100.00%	100.00%	100.00%

Table 3-46 presents the share of self-scheduled, economic, non-economic and regulation generation for each unit type. For example, in 2006 steam units represented 93.90 percent of all economic generation. Table 3-47 presents the share of each unit type for self-scheduled, economic, non-economic and regulation generation. For example, in 2006 45.06 percent of steam unit generation was economic.

Table 3-46 PJM generation by unit type: Calendar year 2006

	Self-Scheduled Generation	Economic Generation	Non-Economic Generation	Regulation Generation
CC	2.57%	4.42%	17.31%	8.69%
CT	0.31%	0.63%	5.64%	0.85%
Diesel	0.14%	0.01%	0.06%	0.00%
Hydroelectric	3.22%	1.04%	0.00%	0.00%
Steam	93.53%	93.90%	76.99%	90.45%
Wind	0.22%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%

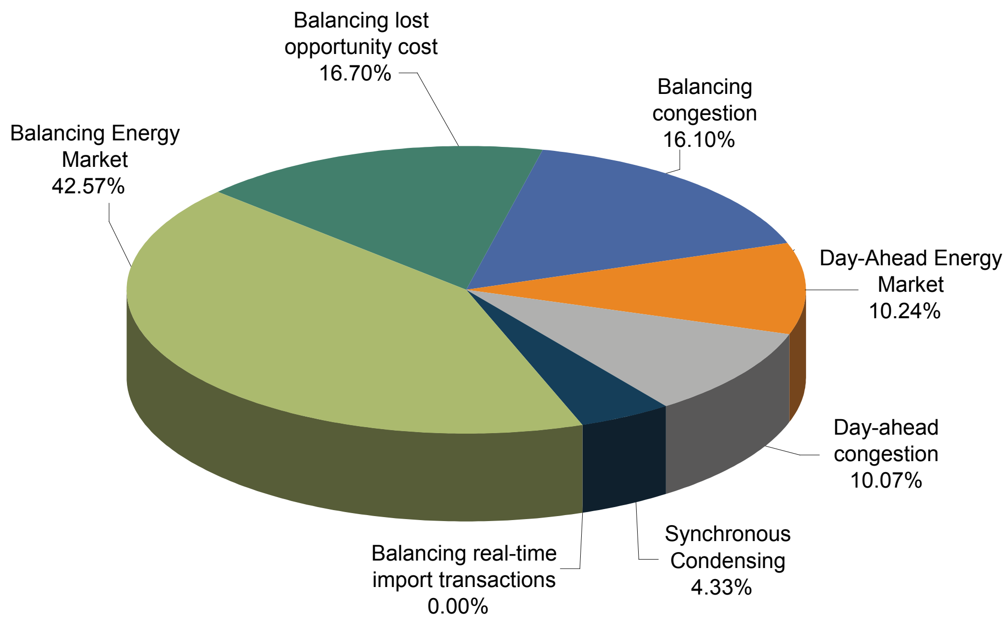
Table 3-47 PJM unit type generation distribution: Calendar year 2006

	Self-Scheduled Generation	Economic Generation	Non-Economic Generation	Regulation Generation	Total
CC	29.14%	45.91%	21.83%	3.12%	100.00%
CT	20.12%	37.57%	40.56%	1.75%	100.00%
Diesel	91.78%	3.74%	4.47%	0.00%	100.00%
Hydroelectric	77.23%	22.77%	0.00%	0.00%	100.00%
Steam	48.95%	45.06%	4.49%	1.50%	100.00%
Wind	100.00%	0.00%	0.00%	0.00%	100.00%

Operating Reserve Credits by Category

Figure 3-12 shows that the largest share of total operating reserve credits, 42.57 percent, was paid to resources in the Balancing Energy Market during 2006 and that 75.36 percent of total operating reserve credits were in the balancing category. Figure 3-12 also shows that 10.24 percent of total operating reserve credits were paid to resources in the Day-Ahead Energy Market and that 20.31 percent of total operating reserve credits were in the day-ahead category.[86]

Figure 3-12 Operating reserve credits: Calendar year 2006



Geography of Balancing Credits and Charges

Table 3-48 compares the share of balancing operating reserve charges paid by and credits paid to generators located within the Mid-Atlantic Region to the share of charges paid by and credits paid to generators located within all other PJM control zones.[87] The other control zones include those in the Western Region (the AEP, AP, ComEd, DAY and DLCO Control Zones) and in the Southern Region (the Dominion Control Zone). On average, 42.78 percent of all generator charges were paid by generators in the Mid-Atlantic Region. On average, 66.11 percent of energy credits, 84.90 percent of congestion credits and 32.39 percent of lost opportunity cost credits were paid to generators in the Mid-Atlantic Region. Table 3-48 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator charges were 27.14 percent of all operating reserve charges and generator credits were 71.36 percent of all operating reserve credits.

These results do not necessarily mean that there is an inappropriate regional allocation of operating reserve charges but reflect the usage of actual resources to meet the need for system operating reserve.

86 The day-ahead import transactions are too small to be shown in Figure 3-12.

87 Balancing operating reserve charges in Table 3-48 include only those in the generator category. Balancing operating reserve credits in Table 3-48 include balancing energy market credits, balancing congestion credits and lost opportunity cost credits. Categories are defined in Table 3-40.

Table 3-48 Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2006

	Mid-Atlantic Region				Other Control Zones					
	Generation Charge	Energy Credit	Congestion Credit	Lost Opportunity Cost	Generation Charge	Energy Credit	Congestion Credit	Lost Opportunity Cost	Generation Charges Share Total Operating Reserve Charges	Generation Credits Share Total Operating Reserve Credits
Jan	42.30%	68.54%	87.89%	44.43%	57.70%	31.46%	12.11%	55.57%	30.04%	67.93%
Feb	36.03%	75.67%	76.03%	38.66%	63.97%	24.33%	23.97%	61.34%	32.74%	74.74%
Mar	38.34%	68.07%	83.14%	49.15%	61.66%	31.93%	16.86%	50.85%	24.78%	60.26%
Apr	39.82%	53.85%	63.76%	13.11%	60.18%	46.15%	36.24%	86.89%	25.53%	57.82%
May	42.32%	63.97%	81.20%	9.20%	57.68%	36.03%	18.80%	90.80%	26.81%	64.13%
Jun	42.78%	73.82%	91.32%	14.77%	57.22%	26.18%	8.68%	85.23%	31.50%	77.02%
Jul	48.04%	75.73%	95.65%	26.03%	51.96%	24.27%	4.35%	73.97%	29.16%	86.36%
Aug	44.78%	72.63%	89.48%	24.17%	55.22%	27.37%	10.52%	75.83%	30.35%	86.98%
Sep	45.81%	78.41%	99.90%	32.28%	54.19%	21.59%	0.10%	67.72%	22.50%	64.94%
Oct	44.10%	56.68%	90.95%	58.24%	55.90%	43.32%	9.05%	41.76%	23.03%	65.13%
Nov	42.89%	38.45%	96.73%	47.34%	57.11%	61.55%	3.27%	52.66%	27.50%	76.43%
Dec	46.15%	67.47%	62.77%	31.33%	53.85%	32.53%	37.23%	68.67%	21.77%	74.64%
Average	42.78%	66.11%	84.90%	32.39%	57.22%	33.89%	15.10%	67.61%	27.14%	71.36%

Market Power Issues

The exercise of market power by units that are paid operating reserve credits is also a contributor to the level of operating reserve charges paid by PJM members. Market power issues are first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The top 10 units are relevant, not because these are the only units with the ability to exercise market power, but because operating reserve credits have been so highly concentrated in payments to these units over the last several years. The market power analysis includes a calculation of the impact on total operating reserve credits of payments to generators associated with markups of price over cost in excess of the competitive level. Unit operating parameters also play a role in the level of operating reserve credits paid to units. The submission of inflexible operating parameters, including artificially long minimum run times, arbitrarily small numbers of starts, daily and hourly economic minimum and economic maximum points that are arbitrarily close or equal, contribute to higher levels of operating reserve credits.

The actions of PJM operators are also part of any analysis of market power affecting the level of operating reserve credits. It is the decisions of PJM operators, constrained by their available tools, by the requirement to maintain system reliability and by the available generating resources, that effectively put units in a position to exercise market power with respect to the payment of operating reserve credits. A complete resolution of the market power issue in the payment of operating reserve credits must provide to PJM operators better tools for defining and making optimal economic choices and must define the relevant market, must determine when the market is structurally noncompetitive and must apply mitigation in such situations.

Top 10 Units

A disproportionate share of balancing and day-ahead operating reserve credits has been paid to a small number of units and companies since 2001. This continued to be the case in 2006 despite the overall reduction in operating reserve charges. As Table 3-49 shows, the top 10 units, less than 1 percent of all units, received 29.7 percent of total operating reserve credits in 2006, an increase over the 27.7 percent in 2005. The top 20 units received 36.9 percent of operating reserve credits in 2006 and 37.2 percent in 2005. In 2005 the top 10 units were owned by four companies and in 2006 the top 10 were owned by five companies. In 2006, two of the top 10 units changed. One of the new units was owned by the same owner as a unit that dropped from the top 10 and one of the new units was owned by a new owner. In 2005 the top generator received 15 percent of the total operating reserve credits paid, and in 2006 the top generator received 16 percent of the total operating reserve credits.

Table 3-49 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2006

	Percent	Top 10 Units Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%

Markup

Unit Markup - Top 10 Units

To determine the contribution that unit price offers, in excess of cost, make to operating reserve payments, the MMU performed a markup analysis of the top 10 units.[88] As Table 3-50 shows, the markup for the top 10 units averaged 21 percent in 2006, a substantial increase over prior years with the exception of 2005 when the markup for the top 10 units averaged 75 percent. The markup for the top 10 units is a weighted-average, where the weights are generator output when operating reserve credits are paid. The decreased markup in 2006 over 2005 resulted from a single top 10 unit having had a substantial, unit-specific markup in 2005.

The generation owner with the largest share of top 10 credits received 69 percent of energy market operating reserve credits paid to the top 10 units and had a weighted-average markup of 0 percent in 2006. The next generation owner received 16 percent of energy market operating reserve payments made to the top 10 units and had a weighted-average markup of 79 percent and the third generation owner received 8 percent of energy market operating reserve payments made to the top 10 units and had a weighted-average

88 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as defined in PJM "Manual 15: Cost Development Guidelines," Revision 7 (August 3, 2006). As a result, the markups here are not directly comparable to those calculated as [(Price – Cost)/Price].

markup of 18 percent in 2006. In 2005 the top owner received 55 percent of energy market operating reserve payments made to the top 10 units and had a weighted-average markup of 235 percent.

For each year 2001 to 2006, the top 10 units receiving operating reserve credits were either CC technology or conventional steam generation. Steam units accounted for a smaller share of the operating reserve credits received by the top 10 units in 2006, representing 10 percent of the credits received by the top 10 in 2006. CC units accounted for a larger share of the operating reserve credits received by the top 10 units in 2006, representing 90 percent of the credits received by the top 10 in 2006, as shown in Table 3-50.

Table 3-50 Top 10 operating reserve revenue units' markup: Calendar years 2001 to 2006

	Top Units' Markup	Steam Percent of Top 10	Steam Markup	CC Percent of Top 10	CC Markup
2001	3%	60%	2%	40%	7%
2002	11%	54%	8%	46%	20%
2003	17%	50%	19%	50%	11%
2004	3%	12%	0%	88%	5%
2005	75%	20%	53%	80%	82%
2006	21%	10%	2%	90%	24%

Unit Markup - All Units

PJM's offer-capping rules provide that specific units are exempt from offer capping, based on their date of construction. Five of the top 10 units are exempt from offer capping for local market power.[89] Table 3-51 shows the simple average markup for generators exempt from offer capping, for generators not exempt from offer capping and for all generators, when balancing operating reserve was paid.[90] For all units, when operating reserve credits were paid, the markup for exempt units was 350 percent larger than the markup for non-exempt units, 27 percent for exempt units and 6 percent for non-exempt units. The associated maximum markups exceeded the average levels by a substantial amount; the maximum markup for an exempt unit was in excess of 130 percent.

89 See *2006 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Exempt Unit Markup."

90 The weighted-average markup calculations are weighted by real-time generation.

Table 3-51 Simple average generator markup: Calendar year 2006

Unit Class	Exempt	Non-Exempt	All Units
All Units	27%	6%	8%
CC	24%	4%	6%
CT	26%	10%	11%
Diesel	69%	8%	14%
Steam	NA	0%	0%

Impact of Markup by Exempt Units

Table 3-52 compares the total balancing operating reserve rate and the balancing operating reserve rate adjusted to remove all markups above 10 percent for exempt units. This comparison shows the impact on operating reserve charges of markups over cost by units exempt from offer-capping rules. The impact is the result of increased markups by the 42 exempt units that received balancing operating reserve credits in 2006.[91] If the exempt units had been subject to offer-capping rules at the times they were paid operating reserve credits, the cumulative current total balancing operating reserve credit in 2006 would have been lower by about $26 million and the balancing operating reserve rate in 2006 would have been 11 percent lower.

Table 3-52 Balancing operating reserve rate for exempt units (Actual and markup-adjusted): Calendar year 2006

	Current Rate	Markup-Adjusted Rate
Jan	1.13	1.05
Feb	1.13	1.02
Mar	0.63	0.60
Apr	0.62	0.61
May	0.83	0.79
Jun	1.10	1.00
Jul	2.30	2.12
Aug	2.68	2.23
Sep	1.19	0.82
Oct	1.14	1.04
Nov	1.32	1.26
Dec	1.86	1.70
Annual Average	1.33	1.19

91 These are the units that received balancing energy and balancing congestion credits.

Unit Operating Parameters

Operating reserve credits also result from the submission of artificially restrictive, unit-specific operating parameters. For example, if a unit is needed by PJM for reliability purposes and if that unit, with a price offer equal to its cost offer, has only one permitted start per day although it is capable of three, has a 24-hour minimum run time although its actual minimum run time is four hours and a two-hour start time although its actual start time is 30 minutes, then it receives higher operating reserve payments than if those operating parameters were not in place. Once a unit is turned on for PJM for reliability reasons, operating reserve rules require that PJM pay the unit the difference between market revenues and its offer, including its offered operating parameters. Thus, PJM members have to pay this unit its offer price for 24 hours although if the unit had offered its actual capability to PJM, payments would have been made for only four hours. If a unit sets its economic minimum output level at or close to its economic maximum output level, although the actual minimum and maximum output levels have a significant differential, PJM members have to pay the unit its offer price for its offered economic minimum. If the unit had offered its actual economic minimum to PJM, PJM could have reduced the unit's output to that minimum when LMP fell below its offer price, thus reducing operating reserve credits and charges. Restrictive operating parameters can also interact with unit-specific markups to increase operating reserve payments to units.

SECTION 4 – INTERCHANGE TRANSACTIONS

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials.

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.[1]

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports.** During 2006, PJM was a net exporter of energy, with monthly net interchange averaging -1.5 million MWh.[2] Gross monthly import volumes averaged 2.2 million MWh while gross monthly exports averaged 3.7 million MWh.

- **Transactions in the Day-Ahead Energy Market.** While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, the share of activity in the Day-Ahead Energy Market has increased substantially. In 2006, gross imports in the Day-Ahead Energy Market were 77 percent of the Real-Time Market's gross imports (50 percent in 2005) while gross exports in the Day-Ahead Market were 86 percent of the Real-Time Market's gross exports (50 percent in 2005) and net interchange in the Day-Ahead Energy Market was almost identical to net interchange in the Real-Time Energy Market.

- **Interface Imports and Exports.**[3] There were net exports at 15 of PJM's 21 interfaces in 2006. Three interfaces accounted for 65 percent of the total net exports, PJM/Tennessee Valley Authority (TVA) with 33 percent, PJM/MidAmerican Energy Company (MEC) with 17 percent and PJM/New York Independent System Operator (NYIS) with 15 percent of the net export volume. There were net imports at five of PJM's interfaces. Three interfaces accounted for 97 percent of the net import volume, PJM/Ohio Valley Electric Corporation (OVEC) with 76 percent, PJM/Illinois Power Company (IP) with 12 percent and PJM/Duke Energy Corp. (DUK) with 9 percent of the net import volume.

1 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."

2 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

3 Interfaces are named after adjacent control areas. As is true of the control areas themselves, this naming convention does not imply anything about any company operating within the control areas.

Interchange Transaction Topics

- **Operating Agreements with Bordering Areas.**
  - **PJM/Midwest ISO Joint Operating Agreement (JOA).** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." continued in its second, and final, phase of implementation including market-to-market activity and coordinated market-based congestion management within and between both markets.[4]
  - **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[5] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2006.
  - **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[6] On September 9, 2005, the United States Federal Energy Regulatory Commission (FERC) approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2006.
- **PJM TLRs.** The number of transmission loading relief procedures (TLRs) issued by PJM declined from 2005. The reduction in TLRs declared by both PJM and the Midwest ISO is evidence that market signals are being used to manage inter area transactions rather than market interventions.
- **PJM Interface Pricing with Organized Markets.**
  - **PJM and Midwest ISO Interface Pricing.** During 2006, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.
  - **PJM and New York ISO Interface Pricing.** During 2006, the relationship between prices at the PJM/NYIS Interface and at the New York Independent System Operator (NYISO) PJM proxy bus reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and NYISO. As in 2005, both continued to be affected by differences in institutional and operating practices between PJM and NYISO.
  - **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.**[7] PJM continued to operate under the terms of the operating protocol (developed in 2005) during 2006.[8] Con Edison, however, is concerned that there have been apparent departures from protocol requirements.

4 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 31, 2003) (Accessed January 8, 2007) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,331 KB).

5 See "Joint Reliability Coordination (JRCA) among the Midwest ISO, PJM and TVA" (April 22, 2005) (Accessed January 17, 2007) <http://www.pjm.com/documents/downloads/agreements/ 20050422-jrca-final.pdf> (145 KB).

6 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed January 17, 2007) <http://www.pjm.com/documents/ferc/ documents/2005/20050729-er05-___-000.pdf> (2.90 MB).

7 Prior state of the market reports indicated that this contract is an agreement between Con Edison and PSEG. The contract is between Con Edison and PSE&G, a wholly owned subsidiary of PSEG.

8 111 FERC ¶ 61,228 (2005).

Periodic meetings were held with all participants to discuss the operation and progress towards improved delivery. Formal filings to implement further improvements are expected in 2007.

Interchange Transaction Issues

- **Loop Flows.** Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths that the energy takes. Although PJM's total scheduled and actual flows differed by less than 2 percent in 2006, there were significant differences for individual interfaces. Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

- **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As in 2005, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight off-peak hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows. The PJM/MECS differences and the PJM/TVA differences were in opposite directions. The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

- **Loop Flows at PJM's Southern Interfaces.** There was a persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) to the west and PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK to the east) that grew larger through the summer. In the southwest for example, while actual flows at the PJM/TVA and PJM/EKPC Interfaces were relatively small exports, scheduled energy exports at these interfaces were very large. The scheduled exports increased further in June, July and August.

  In order to reflect the actual flow of transactions associated with the southwest and southeast interface pricing points, on October 1, 2006, PJM began to price imports and exports differently based on their impacts on the PJM transmission system. After the pricing point change, scheduled flows more closely matched actual flows, primarily as a result of reductions in scheduled flows while actual flows remained relatively unchanged. In particular, a significant level of scheduled exports to the southwest stopped after the modification of the pricing points. A small number of market participants had been regularly scheduling large exports and the decline in their scheduling activity was responsible for most of the improved convergence between actual and scheduled flows.

- **Data Required for Full Loop Flow Analysis.** A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The data to fully analyze loop flows affecting PJM are not currently available to PJM.

- **Wisconsin Public Service Corporation Complaint.** On August 15, 2006, the Wisconsin Public Service Corporation (WPS) filed a complaint against PJM and the Midwest ISO at the FERC requesting that the FERC direct PJM and Midwest ISO (the regional transmission organizations (RTOs)) to promptly institute joint unit commitment and dispatch over the entire PJM/MISO footprint. The RTOs responded that an appropriate cost-benefit analysis does not justify joint dispatch at the present time. Nonetheless the RTOs recognize that there are actions that can be taken to address the lack of convergence of shadow prices. The RTOs are developing an approach to improve shadow price convergence.

- **Ramp Reservation Rule Change.** In early 2006 the number of market participant complaints regarding the inability to obtain ramp in a timely manner and complaints about large ramp volume swings became more persistent. The MMU's efforts to publicly identify the issues with such conduct resulted in improved behavior, but similar efforts in the past had only temporary effects. As a result, the MMU developed, PJM proposed, and the membership agreed, to changes in the ramp reservation rules to impose limits on the time that a ramp reservation could be held without an associated energy schedule. The new rules had a significant, positive impact on ramp reservation behavior.

Conclusion

Transactions between PJM and the multiple control areas contiguous to PJM are part of a single energy market. While some of these contiguous control areas are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market in the Eastern Interconnection. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and least cost, security-constrained economic dispatch. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are nontransparent.

The PJM Market Monitoring Unit (MMU) analyzed the transactions between PJM and neighboring control areas for 2006 including evolving transactions patterns, economics and issues. PJM continued to be a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 65 percent of the total net exports and three interfaces accounted for 97 percent of the net import volume. While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, the share of activity in the Day-Ahead Energy Market has increased substantially to 77 percent and 86 percent of gross imports and exports, respectively, while net interchange in the Day-Ahead Market is approximately equal to that in the Real-Time Energy Market.

As the data show, there is a substantial level of transactions between PJM and the contiguous control areas. The transactions with other market areas are driven by the market fundamentals within each area and between market areas. However, there is room to improve current market-to-market coordination to ensure that these areas together more closely approach the outcomes and opportunities of a single, transparent market. The transactions with non market areas are driven by a mix of incentives including market fundamentals but are more difficult to manage because of the inherent inconsistency between the contract path approach taken in non market areas and the explicit locational-price-driven approach in market areas. A significant issue is the ability of non market transactions to impose uncompensated costs on market areas in the absence of transparency and appropriate market signals. For interactions with both market and non market areas, the goal is to increase the role of market forces consistent with actual power flows and more closely approach the outcomes and opportunities of a single, transparent market.

In order to manage interactions with other market areas, PJM has entered into formal agreements with a number of control areas. The redispatch agreement between PJM and the Midwest ISO is a model for such agreements and is being continuously improved. As interactions with external areas are increasingly governed by economic fundamentals, interface prices and volumes reflect supply and demand conditions and the number of required interventions in the market has declined, as measured for example by the reduction in TLRs declared by both PJM and the Midwest ISO in 2006.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other control areas as a first step. In addition, PJM has attempted to address loop flows by creating and modifying interface prices that reflect actual power flows, regardless of contract path. Loop flows are also managed through the use of redispatch and TLR procedures. PJM has entered into dynamic scheduling agreements with generation owners to permit transparent, market-based signals and responses. PJM has modified the rules governing the use of limited transaction ramp capability between PJM and contiguous control areas to help ensure that transactions are free to respond to market signals and to reduce the ability to game or hoard ramp.

Loop flows are measured as the difference between actual and scheduled (contract path) flows at one or more specific interfaces. Loop flows do not exist within markets because power flows are explicitly priced under locational marginal pricing, but markets can create loop flows in external control areas. PJM attempts to manage loop flows by creating interface prices that reflect the actual power flows, regardless of contract path. As one approach to a specific loop flow issue, the southeast and southwest pricing points were consolidated into a single pricing point with separate import and export pricing. But this approach cannot be completely successful as long as it is possible to schedule a transaction and be paid based on that schedule, regardless of how the power flows.

PJM continues to face significant loop flows for reasons that are not yet fully understood, in large part as a result of inadequate access to the required data. A complete analysis of loop flow across the Eastern Interconnection could improve overall market efficiency and enhance the transparency of the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas.

Market participants at times request and receive ramp reservations that are not actually used for an energy transaction. When this happens, other market participants can be prevented from obtaining ramp reservations and PJM operations and markets can be affected by the large, last minute changes in expected external power flow. This behavior can reflect attempts to manipulate PJM prices, attempts to disadvantage competitors, mistakes by participants or unanticipated failures to complete the underlying transaction.

In response, the MMU developed, PJM proposed, and the membership supported, changes in the import and export ramp reservation rules to impose limits on the time that a ramp reservation could be held without an associated energy schedule. These changes became effective on August 7, 2006. The distributed nature of automatic expirations under the new rule has improved the efficiency of ramp usage.

PJM has also successfully used other approaches to enhance the efficiency of interactions with neighboring control areas. The Con Edison/PSE&G wheeling contracts continue to be managed under the FERC-approved protocol that has improved operations and resulted in more explicit pricing for the associated power flows.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM continues to be a net exporter of power. (See Figure 4-1 and Figure 4-3.)

During 2006, PJM was a net exporter of energy for each month. Total net interchange of -18.1 million MWh exceeded net interchange of -17.0 million MWh in 2005. The peak month for net interchange was June in 2006, -2.7 million MWh, and was January in 2005, -1.8 million MWh. Monthly gross exports averaged 3.7 million MWh and monthly gross imports averaged 2.2 million MWh for an average monthly net interchange of -1.5 million MWh.

While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, the share of activity in the Day-Ahead Energy Market has increased substantially. (See Figure 4-2.) Transactions in the Day-Ahead Market create a financial obligation to deliver in the Real-Time Market and the obligation to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Market. In 2006, gross imports in the Day-Ahead Energy Market were 77 percent of the Real-Time Market's gross imports (50 percent in 2005) while gross exports in the Day-Ahead Market were 86 percent of the Real-Time Market's gross exports (50 percent in 2005) and net interchange in the Day-Ahead Energy Market was almost identical to net interchange in the Real-Time Energy Market.

Figure 4-1 PJM real-time imports and exports: Calendar year 2006

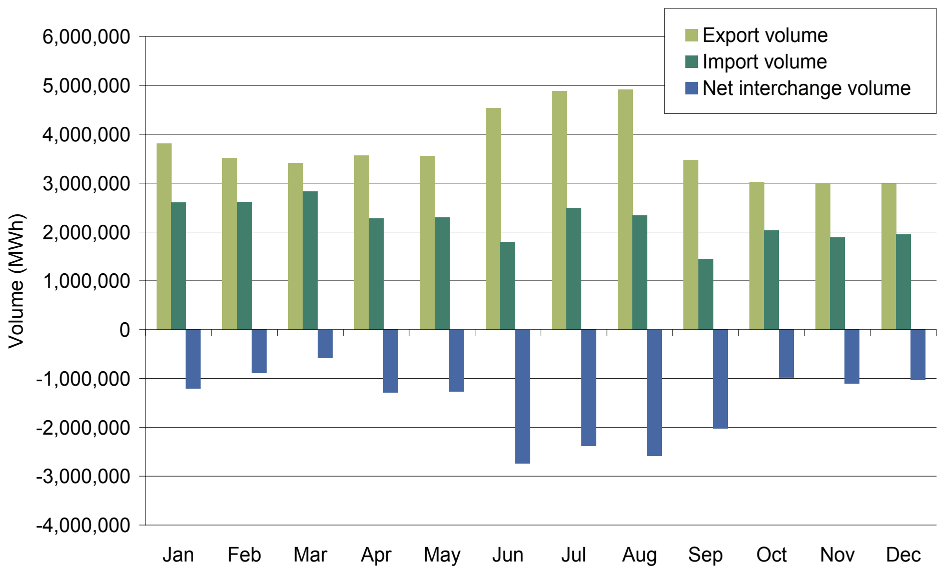


Figure 4-2 PJM day-ahead imports and exports: Calendar year 2006

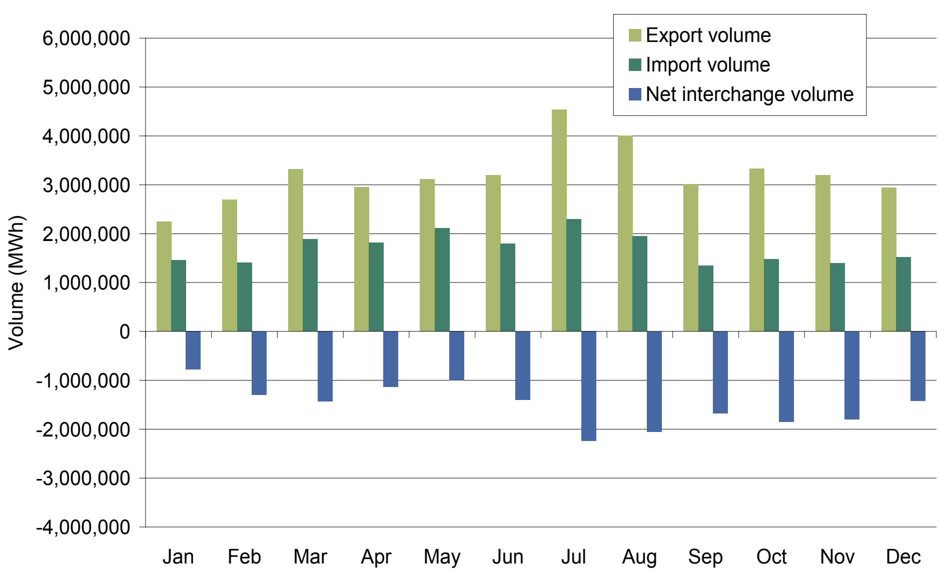
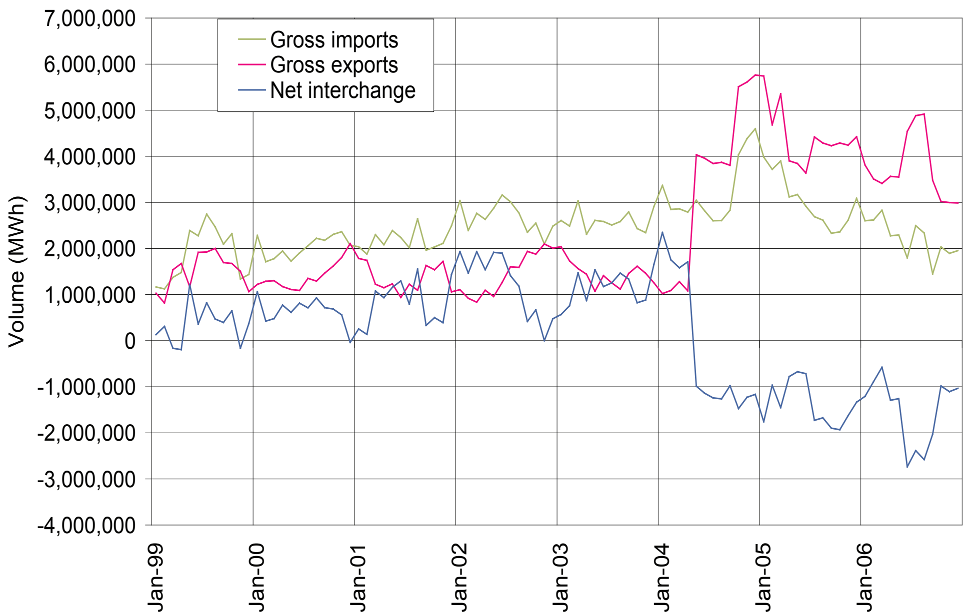


Figure 4-3 shows import and export volume for PJM from 1999 through 2006. Gross exports exhibited a particularly sharp increase in early 2004 that was not matched by imports while the increase in gross exports and imports in late 2004 was more balanced. During 2005, gross imports and exports generally declined while net interchange fluctuated with no clear trend. In 2006, imports continued to trend lower and exports, after peaking in midyear, also declined to below 2005 monthly levels by December 31, 2006. Net interchange fluctuated with no clear trend.

Figure 4-3 PJM import and export transaction volume history: Calendar years 1999 to 2006



Interface Imports and Exports

Total imports and exports are comprised of flows at each PJM interface. Net interchange in the Real-Time Market is shown by interface for 2006 in Table 4-1 while gross imports and exports are shown in Table 4-2 and Table 4-3.

There were net exports in the Real-Time Market at 15 of PJM's 21 interfaces in 2006. Three interfaces accounted for 65 percent of the total net exports, PJM/TVA with 33 percent, PJM/MEC with 17 percent and PJM/NYIS with 15 percent of the net export volume. Export transactions in the Day-Ahead Market were highest at the PJM/Northern Indiana Public Service Company (PJM/NIPS) and PJM/NYIS Interfaces in 2006. PJM/NIPS accounted for 21 percent and PJM/NYIS accounted for 17 percent of the average hourly volume.

There were net imports in the Real-Time Market at five of PJM's interfaces. Three interfaces accounted for 97 percent of the net import volume, PJM/OVEC with 76 percent, PJM/IP with 12 percent and PJM/DUK with 9 percent of the net import volume. Import transactions in the Day-Ahead Market were highest at the PJM/OVEC and PJM/NYIS Interfaces during 2006. PJM/OVEC accounted for 50 percent and PJM/NYIS accounted for 29 percent of the average hourly volume.

Table 4-1 Net interchange volume by interface (MWh x 1,000): Calendar year 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	(113.5)	(103.4)	(80.5)	(55.5)	(73.5)	(70.0)	(100.9)	(115.3)	(89.0)	(63.3)	(44.5)	(61.6)	(971.0)
ALTW	(114.1)	(88.3)	(92.9)	(49.2)	(50.8)	(24.6)	(88.7)	(104.2)	(84.5)	(90.3)	(88.8)	(83.5)	(959.9)
AMRN	(147.0)	(157.8)	(133.4)	(107.4)	(138.7)	(142.9)	(63.1)	(128.8)	(44.7)	(58.0)	(35.3)	(70.6)	(1,227.7)
CILC	0.0	0.0	(68.4)	(20.6)	0.0	(17.7)	(2.4)	0.1	(20.2)	0.0	3.4	1.0	(124.8)
CIN	(98.9)	(29.7)	(18.3)	30.6	10.4	(346.2)	(571.3)	(334.4)	(70.9)	107.2	73.1	(43.2)	(1,291.6)
CPLE	110.9	208.4	86.6	(3.8)	0.6	(129.3)	(124.5)	(148.0)	(157.7)	(39.3)	(137.7)	(106.5)	(440.3)
CPLW	(74.4)	(66.7)	(74.4)	(75.5)	(54.1)	(71.3)	(73.4)	(78.8)	(75.1)	(64.7)	(71.5)	(76.6)	(856.5)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	405.1	699.4	495.8	(89.5)	48.0	(58.2)	169.7	(94.5)	(21.9)	(134.1)	(197.9)	(54.1)	1,167.8
EKPC	(71.8)	(56.2)	(78.2)	(57.3)	(61.1)	(29.3)	(13.0)	(15.3)	(27.2)	(20.1)	(51.5)	(41.7)	(522.7)
FE	(96.0)	(145.8)	(203.6)	(169.7)	(198.9)	(184.9)	(195.2)	(226.2)	(170.8)	(197.8)	(209.7)	(206.7)	(2,205.3)
IP	311.0	20.7	330.5	325.0	340.9	20.9	31.4	6.9	4.6	69.6	81.4	9.5	1,552.4
IPL	(0.3)	(1.0)	(0.3)	0.0	(0.2)	0.0	(1.3)	(0.4)	0.0	(0.2)	(0.3)	(0.3)	(4.3)
LGEE	(1.3)	(1.0)	(0.4)	6.0	7.4	6.9	0.6	(10.1)	36.8	86.4	142.1	46.8	320.2
MEC	(559.3)	(544.3)	(326.3)	(156.0)	(224.7)	(524.3)	(784.7)	(614.4)	(377.2)	(466.3)	(395.8)	(389.8)	(5,363.1)
MECS	(110.5)	(89.8)	(105.2)	(133.6)	(132.7)	(104.8)	(137.7)	(110.6)	(92.8)	(57.1)	(81.9)	(64.4)	(1,221.1)
NIPS	(4.6)	0.9	(16.7)	(4.0)	(0.7)	(6.6)	3.9	(3.2)	(4.7)	59.9	63.2	23.4	110.8
NYIS	(526.0)	(335.1)	(219.5)	(508.5)	(564.4)	(491.9)	205.4	139.0	(744.5)	(439.9)	(686.9)	(337.0)	(4,509.3)
OVEC	846.7	828.0	880.5	826.7	823.5	778.0	711.5	837.2	645.0	836.3	826.8	886.2	9,726.4
TVA	(863.9)	(937.8)	(870.9)	(970.8)	(895.8)	(1,236.7)	(1,228.2)	(1,450.9)	(643.6)	(420.5)	(206.3)	(375.5)	(10,100.9)
WEC	(99.2)	(90.6)	(82.7)	(77.5)	(95.8)	(105.2)	(124.6)	(127.8)	(89.0)	(92.4)	(86.4)	(88.7)	(1,159.9)
Total	(1,207.1)	(890.1)	(578.3)	(1,290.6)	(1,260.6)	(2,738.1)	(2,386.5)	(2,579.7)	(2,027.4)	(984.6)	(1,104.5)	(1,033.3)	(18,080.8)

Table 4-2 Gross import volume by interface (MWh x 1,000): Calendar year 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	0.4	0.0	0.6	0.1	4.9	0.1	15.9	0.0	6.7	16.1	32.5	13.8	91.1
ALTW	0.8	0.1	0.6	0.1	0.3	0.1	0.1	0.1	0.0	0.1	0.0	0.0	2.3
AMRN	50.6	49.1	53.4	67.1	59.9	49.2	88.9	48.2	79.9	65.8	81.4	71.8	765.3
CILC	0.0	0.0	2.1	5.2	0.0	0.0	0.4	0.1	0.0	0.0	3.6	1.1	12.5
CIN	93.9	138.8	163.7	177.1	168.9	79.5	135.7	97.0	65.2	186.0	128.0	120.9	1,554.7
CPLE	303.7	399.4	259.2	152.9	169.8	104.7	144.5	138.1	69.9	145.4	59.0	115.9	2,062.5
CPLW	1.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	512.2	776.8	612.2	258.5	263.5	246.8	409.9	344.5	185.6	90.8	137.5	138.5	3,976.8
EKPC	0.0	0.1	1.3	0.0	0.0	0.7	2.9	5.6	0.9	8.9	8.0	5.2	33.6
FE	81.0	20.9	6.6	23.0	33.4	19.6	50.1	8.6	2.6	5.3	0.3	3.2	254.6
IP	312.0	20.9	331.0	325.0	341.2	20.9	31.4	7.5	4.6	69.6	81.4	9.5	1,555.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LGEE	0.2	0.0	0.0	8.5	7.9	7.5	14.9	10.5	43.4	89.0	143.6	48.9	374.4
MEC	32.3	21.4	24.2	97.9	117.8	71.3	34.2	69.3	89.7	49.2	69.9	120.2	797.4
MECS	13.4	19.3	19.6	34.0	10.8	4.2	9.6	1.3	0.1	25.2	4.7	20.5	162.7
NIPS	0.0	2.1	1.4	1.1	1.5	1.0	13.5	0.5	2.2	61.8	67.0	29.4	181.5
NYIS	340.6	315.4	451.0	286.2	275.8	397.5	808.8	738.8	220.5	349.6	216.0	346.6	4,746.8
OVEC	852.2	831.6	895.2	831.8	823.5	786.6	711.5	845.4	651.5	859.0	826.8	894.4	9,809.5
TVA	8.2	22.1	9.9	6.0	12.1	8.9	23.8	17.2	27.0	12.0	26.8	9.5	183.5
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	0.0	1.6	6.4	4.3	14.1
Total	2,602.6	2,618.5	2,832.0	2,274.5	2,291.3	1,798.6	2,496.1	2,334.5	1,449.8	2,035.4	1,892.9	1,953.7	26,579.9

Table 4-3 Gross export volume by interface (MWh x 1,000): Calendar year 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	113.9	103.4	81.1	55.6	78.4	70.1	116.8	115.3	95.7	79.4	77.0	75.4	1,062.1
ALTW	114.9	88.4	93.5	49.3	51.1	24.7	88.8	104.3	84.5	90.4	88.8	83.5	962.2
AMRN	197.6	206.9	186.8	174.5	198.6	192.1	152.0	177.0	124.6	123.8	116.7	142.4	1,993.0
CILC	0.0	0.0	70.5	25.8	0.0	17.7	2.8	0.0	20.2	0.0	0.2	0.1	137.3
CIN	192.8	168.5	182.0	146.5	158.5	425.7	707.0	431.4	136.1	78.8	54.9	164.1	2,846.3
CPLE	192.8	191.0	172.6	156.7	169.2	234.0	269.0	286.1	227.6	184.7	196.7	222.4	2,502.8
CPLW	75.5	67.2	74.4	75.5	54.1	71.3	73.4	78.8	75.1	64.7	71.5	76.6	858.1
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	107.1	77.4	116.4	348.0	215.5	305.0	240.2	439.0	207.5	224.9	335.4	192.6	2,809.0
EKPC	71.8	56.3	79.5	57.3	61.1	30.0	15.9	20.9	28.1	29.0	59.5	46.9	556.3
FE	177.0	166.7	210.2	192.7	232.3	204.5	245.3	234.8	173.4	203.1	210.0	209.9	2,459.9
IP	1.0	0.2	0.5	0.0	0.3	0.0	0.0	0.6	0.0	0.0	0.0	0.0	2.6
IPL	0.3	1.0	0.3	0.0	0.2	0.0	1.3	0.4	0.0	0.2	0.3	0.3	4.3
LGEE	1.5	1.0	0.4	2.5	0.5	0.6	14.3	20.6	6.6	2.6	1.5	2.1	54.2
MEC	591.6	565.7	350.5	253.9	342.5	595.6	818.9	683.7	466.9	515.5	465.7	510.0	6,160.5
MECS	123.9	109.1	124.8	167.6	143.5	109.0	147.3	111.9	92.9	82.3	86.6	84.9	1,383.8
NIPS	4.6	1.2	18.1	5.1	2.2	7.6	9.6	3.7	6.9	1.9	3.8	6.0	70.7
NYIS	866.6	650.5	670.5	794.7	840.2	889.4	603.4	599.8	965.0	789.5	902.9	683.6	9,256.1
OVEC	5.5	3.6	14.7	5.1	0.0	8.6	0.0	8.2	6.5	22.7	0.0	8.2	83.1
TVA	872.1	959.9	880.8	976.8	907.9	1,245.6	1,252.0	1,468.1	670.6	432.5	233.1	385.0	10,284.4
WEC	99.2	90.6	82.7	77.5	95.8	105.2	124.6	129.6	89.0	94.0	92.8	93.0	1,174.0
Total	3,809.7	3,508.6	3,410.3	3,565.1	3,551.9	4,536.7	4,882.6	4,914.2	3,477.2	3,020.0	2,997.4	2,987.0	44,660.7

Interface Pricing Points

Interface pricing points differ from interfaces. Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[9] PJM establishes prices for transactions with external control areas by assigning interface pricing points to individual areas. Interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically for areas that are both adjacent to and not adjacent to PJM. Transactions between PJM and external control areas need to be priced at the PJM border. A set of external buses is used to create such interface prices.[10] The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and external sources of energy and, therefore, to create price signals that embody underlying economic fundamentals.[11]

9 See *2006 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more detailed discussion of interface pricing.

10 See PJM, "LMP Aggregate Definitions" (December 15, 2006) (Accessed January 8, 2007) <http://www.pjm.com/markets/energy-market/downloads/20061215-aggregate-definitions.xls> (1,307 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

11 See *2006 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Table 4-4 presents the interface pricing points used during 2006.[12] On October 1, 2006, the southeast and southwest pricing points were consolidated, and the south import (SOUTHIMP) and south export (SOUTHEXP) pricing points were created to address loop flow problems.

Table 4-4 Active pricing points: Calendar year 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MICHFE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP										Active	Active	Active
SOUTHEXP										Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active			
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active			

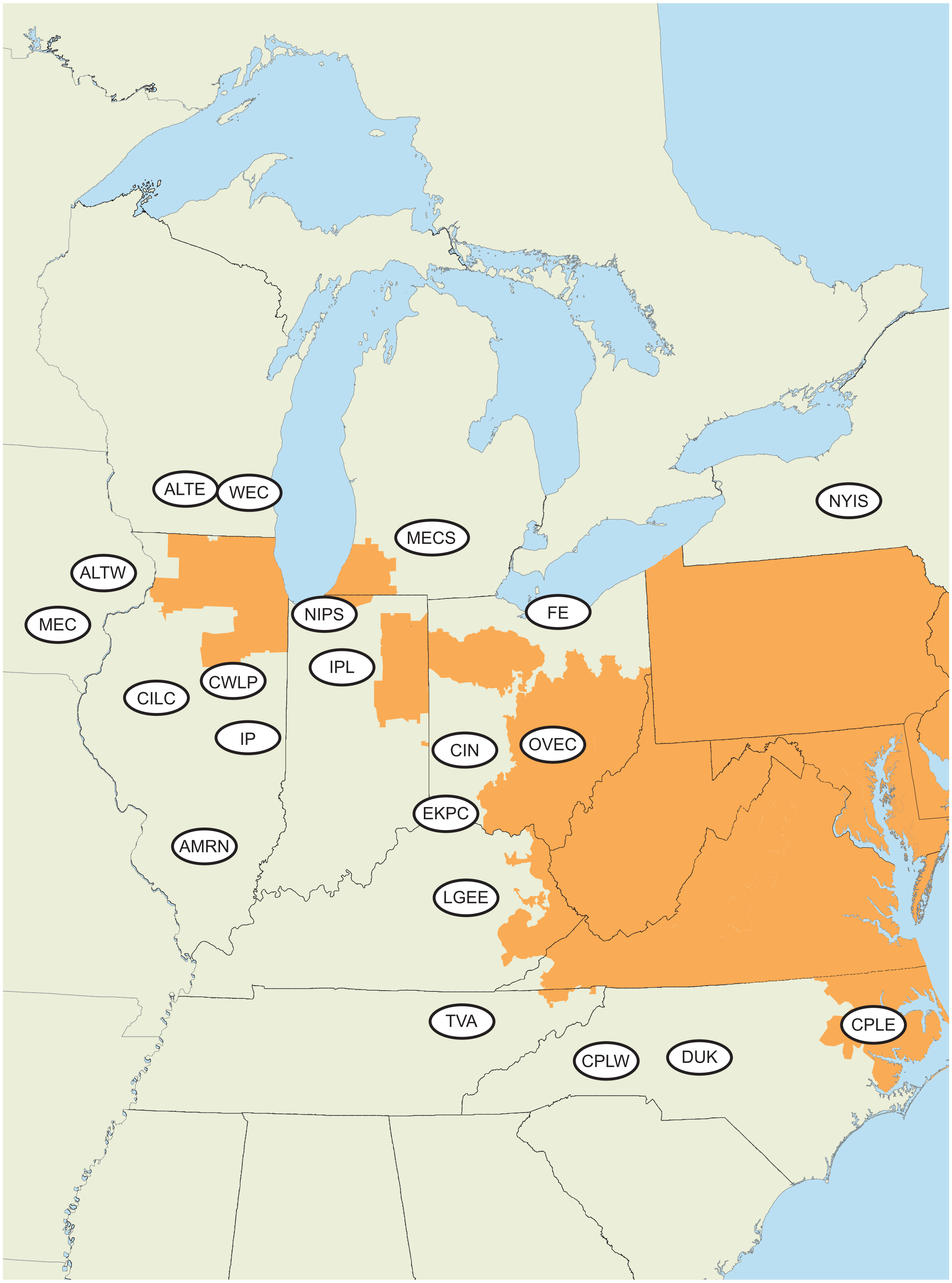
Table 4-5 Active interfaces: Calendar year 2006

PJM 2006 External Interfaces						
ALTE	ALTW	AMRN	CILC	CIN	CPLE	CPLW
CWLP	DUK	EKPC	FE	IP	IPL	LGEE
MEC	MECS	NIPS	NYIS	OVEC	TVA	WEC

The approximate geographic location of these interfaces can be seen in Figure 4-4.

12 For a more detailed discussion of this issue, see *2006 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Loop Flows at PJM's Southern Interfaces."

Figure 4-4 PJM's footprint and its external interfaces



Interchange Transaction Topics

During 2006, four broad topics emerged involving interchange transactions: PJM continued operating under agreements with bordering areas; PJM TLRs continued to be displaced by economic dispatch; PJM continues to face significant loop flow issues; and PJM addressed a problem with ramp reservation abuses that resulted in a rule change.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams' issues, PJM and its neighbors have developed and continue to work on joint operating agreements. These agreements are in various stages of development and include an implemented operating agreement with Midwest ISO, an implemented reliability agreement with TVA and an operating agreement with Progress Energy Carolinas, Inc. that is not yet fully implemented.

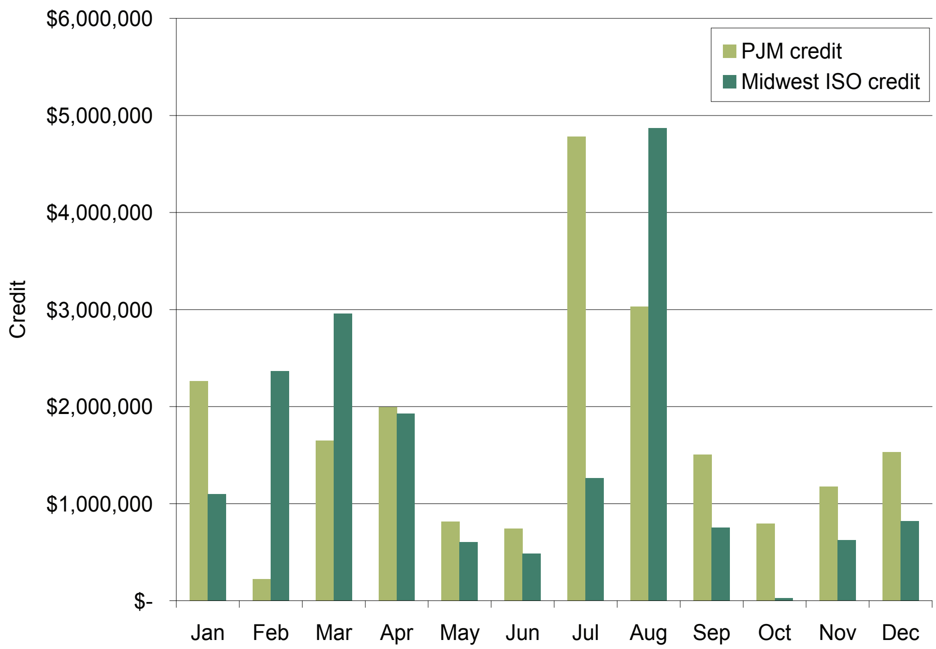
PJM/Midwest ISO Joint Operating Agreement (JOA)

On April 1, 2005, the Midwest ISO market became operational. That triggered the second, market-to-market phase, of the JOA. This second phase remained in effect through 2006.

Under the market-to-market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculate locational marginal prices (LMPs) for its interface with the other organization. Both entities calculate LMPs using network models including distribution factor impacts. PJM uses nine buses within the Midwest ISO to calculate the PJM/MISO pricing point LMP while the Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM pricing point.

In 2006, the market-to-market operations have resulted both in Midwest ISO and PJM redispatching units to control congestion in the other's area and in the exchange of payments for this redispatch. Figure 4-5 presents the monthly credits each organization has received from redispatching for the other. The largest payments from PJM to Midwest ISO during the year were the result of redispatch by Midwest ISO to relieve congestion on the Kammer #8 transformer for the loss of the Belmont–Harrison 500 kV line that was the result of PJM dispatch to meet load. Total PJM payments to Midwest ISO were $15.0 million. The largest payments from Midwest ISO to PJM during the year were the result of redispatch by PJM to relieve congestion on the Black Oak–Bedington 500 kV line for loss of the Pruntytown–Mount Storm 500 kV line that was the result of Midwest ISO dispatch to meet load. Total Midwest ISO payments to PJM were $17.7 million.

Figure 4-5 Credits for coordinated congestion management: Calendar year 2006



PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2006. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Similar to the JOA between PJM and the Midwest ISO, the JRCA uses coordinated flowgates to address congestion within and across systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2006. Since Progress Energy Carolinas is not a market system, the coordination between PEC and PJM is similar to that between the Midwest ISO and PJM during the first phase of their JOA. PEC and PJM plan to control flows over coordinated flowgates with a combination of redispatch and TLRs. The details that were expected to be completed during the first half of 2006 are still being developed. A phased approach is being discussed.

PJM TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve the issue. TLRs are generally called to control flows related to external control areas as redispatch within an LMP market can generally resolve overloads on internal transmission facilities. PJM called fewer TLRs in 2006 than had been called in 2005. Total PJM TLRs declined by 58 percent, from 326 during 2005 to 136 in 2006. (See Figure 4-6.) In addition, the number of unique flowgates for which PJM declared TLRs decreased from 69 different flowgates during 2005 to 41 different flowgates in 2006. (See Figure 4-7 for monthly data.) Of the 136 TLRs called by PJM in 2006, three facilities comprised 50 percent of the total. The three facilities were:

- **Roseland-Cedar Grove F 230 kV Line for Loss of Roseland-Cedar Grove B 230 kV Line.** These parallel path lines are located in northern New Jersey. Power transfers to New York, loop flows and loads on the PSE&G system are the main reasons for TLRs on this line (29 TLRs in 2006; 39 TLRs in 2005);

- **Wylie Ridge Transformers.** These transformers are in a 500 kV substation located in West Virginia near the Ohio River at the western edge of the AP Control Zone. West–to-east power flows frequently overload one of these transformers on a contingency basis for the loss of the other transformer (23 TLRs in 2006; 67 TLRs in 2005);

- **Kammer #200 765 to 500 kV Transformer for Loss of Belmont-Harrison 500 kV Line.** This is a 765 to 500 kV transformer located near the border of Ohio and West Virginia. The Belmont–Harrison 500 kV line runs in northern West Virginia near the southwest corner of Pennsylvania. Economic dispatch of lower cost units in the west can cause high flows at Kammer. This constraint is not easily controllable with redispatch because of lack of generation with the necessary impact (16 TLRs in 2006; 50 TLRs in 2005).

In 2006, the top three facilities for which PJM called TLRs were the same as in 2005 although the total number of TLRs on each of these facilities declined.

Figure 4-6 PJM and Midwest ISO TLR procedures: Calendar years 2005 and 2006

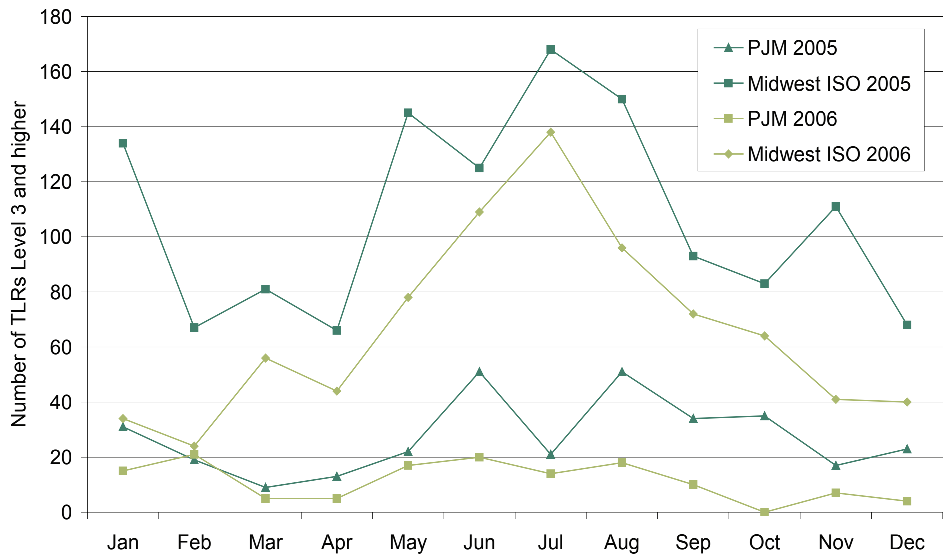
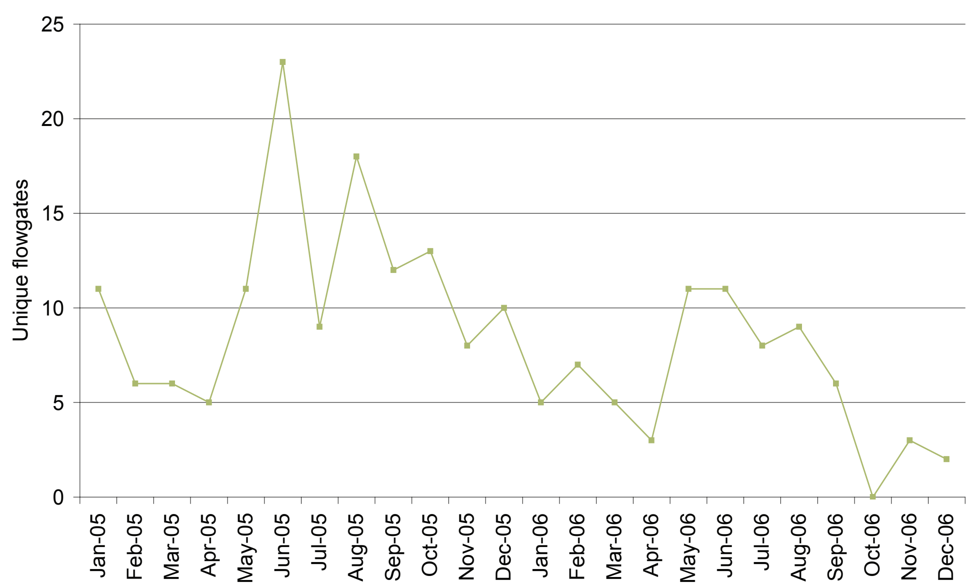


Figure 4-7 Number of unique PJM flowgates: Calendar years 2005 to 2006



PJM Interface Pricing with Organized Markets

During 2006, prices at the borders between PJM and the Midwest ISO and between PJM and the NYISO were consistent with competitive forces. A wheeling contract between New York's Con Edison and New Jersey's PSE&G required involvement from both PJM and NYISO as operators of the relevant transmission facilities.

PJM and Midwest ISO Interface Pricing

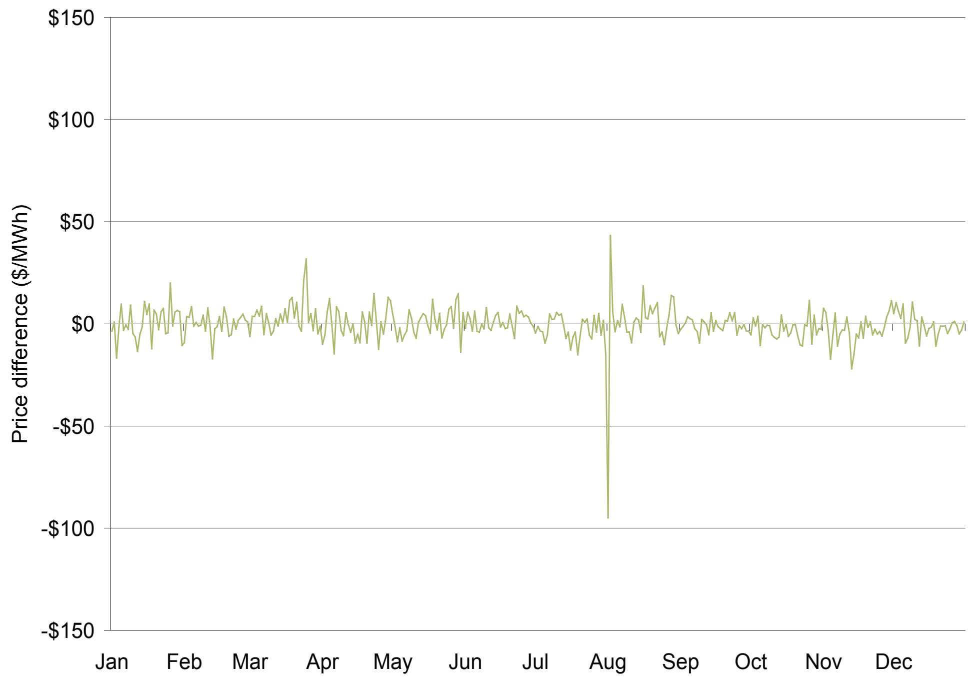
On April 1, 2005, with the introduction of price-based markets, the Midwest ISO created a new interface pricing point with PJM. Both the PJM/MISO and the MISO/PJM pricing points represent the value of power at the relevant border, as determined by each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from Midwest ISO would receive the PJM/MISO price upon entering PJM, while a transaction into Midwest ISO from PJM would receive the MISO/PJM price when entering Midwest ISO. PJM and Midwest ISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[13] within Midwest ISO to calculate the PJM/MISO interface price while Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM interface price.[14]

The 2006 hourly average interface prices for PJM/MISO and MISO/PJM were $41.80 and $41.57, respectively. The simple average difference between the MISO/PJM interface price and the PJM/MISO interface price was -$0.23 in 2006, less than 1 percent of the average PJM/MISO price. (See Figure 4-8.) The PJM/MISO interface price was slightly higher on average than the MISO/PJM price in 2006. The simple average interface price difference does not reflect the underlying hourly variability in prices during 2006.

13 See PJM, "LMP Aggregate Definitions" (December 15, 2006) (Accessed January 8, 2007) <http://www.pjm.com/markets/energy-market/downloads/20061215-aggregate-definitions.xls> (1,307 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

14 Based on information obtained from the Midwest ISO Extranet (October 21, 2005) <http://extranet.midwestiso.org/>.

Figure 4-8 Daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2006



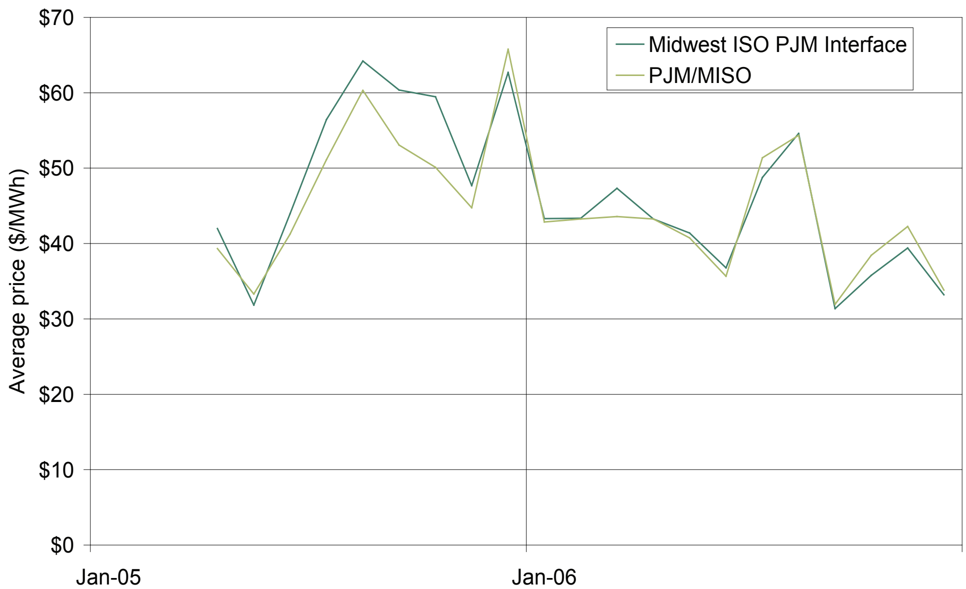
There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

During 2006, the difference between the PJM/MISO interface price and the MISO/PJM interface price fluctuated between positive and negative about eight times per day. The standard deviation of hourly price was $26.18 for the PJM/MISO price and $25.73 for the MISO/PJM interface price. The standard deviation of the difference in interface prices was $20.94. The average of the absolute value of the hourly price difference was $11.60. Absolute values reflect price differences regardless of whether they are positive or negative.

Several factors are responsible for the relationship between interface prices. The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, an observation further supported by the frequency with which price differential switches between positive and negative.

In addition, there is a significant correlation between monthly average hourly PJM and Midwest ISO interface prices during the 2006 period. Figure 4-9 shows this correlation between hourly PJM and Midwest ISO interface prices.

Figure 4-9 Monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 to 2006



PJM and NYISO Interface Pricing

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[15]

PJM's price for transactions with the NYISO, termed the NYIS pricing point by PJM, represents the value of power at the PJM-NYISO border, as determined by the PJM market. PJM defines its NYIS pricing point using two buses.[16] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO-PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as price-capped load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

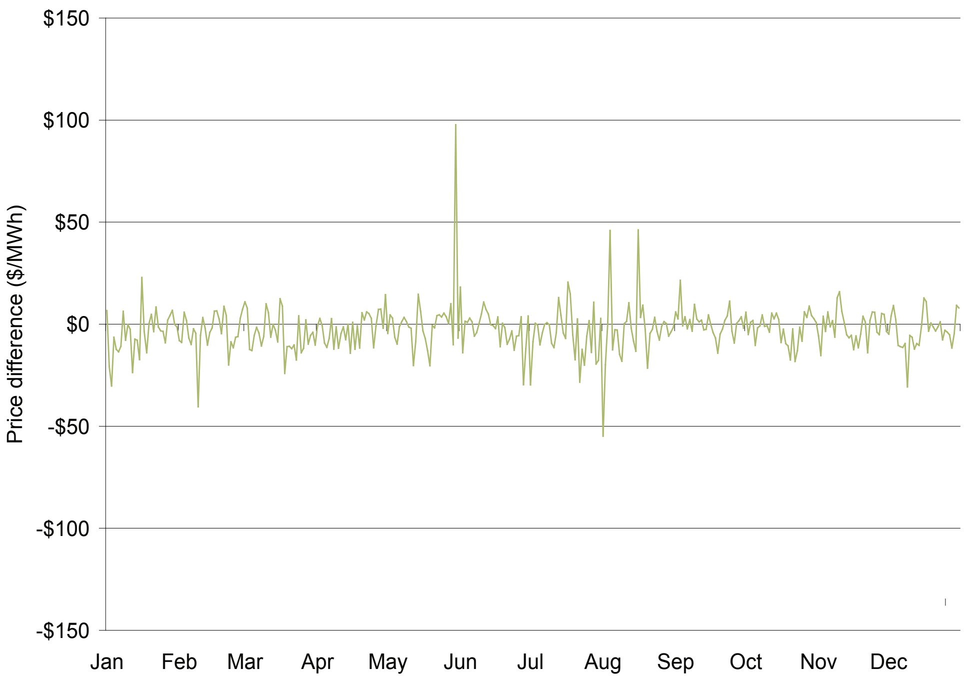
The 2006 hourly average price for PJM/NYIS and the NYISO/PJM proxy bus price were $53.44 and $50.97, respectively. The simple average difference between the PJM/NYIS interface price and the NYISO/PJM proxy bus price decreased from -$5.32 per MWh in 2005 to -$2.47 per MWh in 2006, and the variability of

15 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).

16 See PJM, "LMP Aggregate Definitions" (December 15, 2006) (Accessed January 8, 2007) <http://www.pjm.com/markets/energy-market/downloads/20061215-aggregate-definitions.xls> (1,307 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

the difference also decreased. (See Figure 4-10.) The fact that PJM's net export volume to New York for 2006 was 49 percent lower than the five-year, 2001-to-2005 average is at least partially consistent with the fact that the PJM/NYIS price continued to be greater than the NYISO/PJM price. The simple average interface price difference does not reflect the continuing, substantial underlying hourly variability in prices during 2005 and 2006.

Figure 4-10 Daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2006



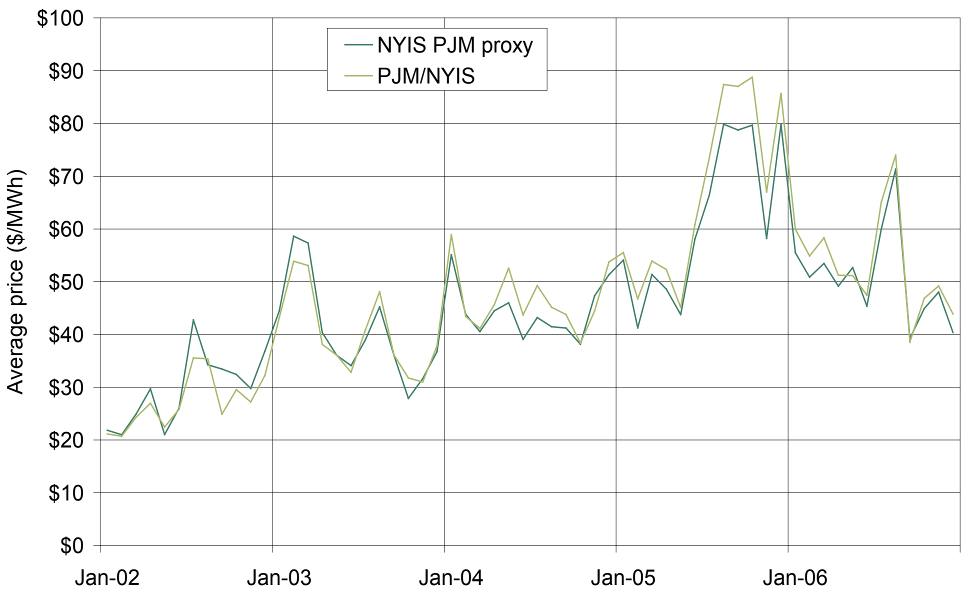
There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

The difference between the PJM/NYIS interface price and the NYISO/PJM price continued to fluctuate between positive and negative about eight times per day during 2006 as it did in 2003, 2004 and 2005. The standard deviation of hourly price was $25.00 in 2003, $23.64 in 2004, $42.93 in 2005 and $35.23 in 2006 for the PJM/NYIS price and $37.72 in 2003, $30.00 in 2004, $41.57 in 2005 and $38.07 in 2006 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $36.21 in 2003, $29.55 in 2004, $40.22 in 2005 and $32.84 in 2006. The average of the absolute value of the hourly price difference was $16.13 in 2003, $14.01 in 2004, $23.44 in 2005 and $17.20 in 2006. Absolute values reflect the price differences without regard to whether they are positive or negative.

A number of factors are responsible for the observed relationship between interface prices. The fact that the simple average of interface prices is relatively small suggests that competitive forces prevent price deviations from persisting. That is further supported by the frequency with which the price differential switches between positive and negative. However, continuing significant variability in interface prices is consistent with the fact that interface prices are defined and established differently, making it difficult for prices to equalize, regardless of other factors.

There is a significant correlation between monthly average hourly PJM and NYISO interface prices during the entire period 2002 to 2006. Figure 4-11 shows this correlation between hourly PJM and NYISO interface prices.

Figure 4-11 Monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2006



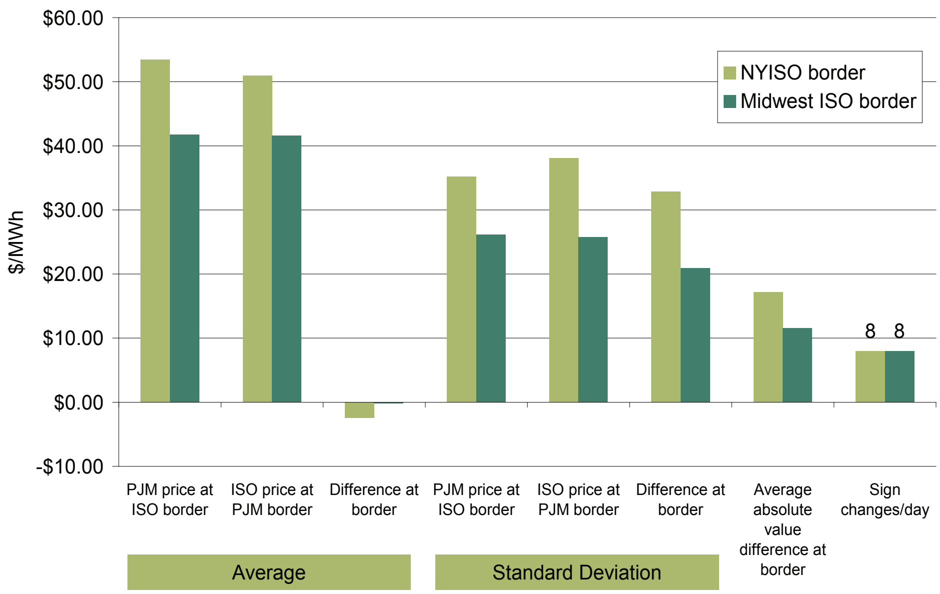
As previously noted, institutional difference between PJM and NYISO markets partially explains observed differences in border prices.[17]

Summary of Interface Pricing with Organized Markets

The key features of PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-12, including average prices and measures of variability.

17 For a description of those differences, see *2005 State of the Market Report,* Appendix D, "Interchange Transactions" (March 8, 2006), pp. 195-198.

Figure 4-12 PJM, NYISO and Midwest ISO border price averages: Calendar year 2006



Con Edison and PSE&G Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[18] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[19]

The protocol allows Con Edison to elect up to the contracted flow under each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion charges associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

18 111 FERC ¶ 61,228 (2005).

19 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2006, PSE&G's FTR revenues were less than the associated congestion charges by $0.4 million ($2.1 million in 2005) because, for the entire PJM FTR Market, revenue was insufficient to fully fund FTRs. Under the FERC order, Con Edison receives credits on an hourly basis for up to the amount of its congestion charges associated with its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. For the year, Con Edison's congestion credits were less than the associated congestion charges by $0.7 million ($8.2 million in 2005). (See Table 4-6.)

Table 4-6 Con Edison and PSE&G wheeling settlements data: Calendar year 2006

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total	Congestion Charge	$2,697,020.88	$9,165.13	$2,706,186.01	$4,159,260.00	$0.00	$4,159,260.00
	Congestion Credit			$2,036,783.63			$3,645,087.51
	Credit Adj.			$0.00			$158,833.43
	Net Charge			$669,402.38			$355,339.06

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. As a general matter, this has not occurred.

2006 Update

PJM continued to operate under the terms of the protocol during 2006. Con Edison, however, is concerned that there have been apparent departures from protocol requirements. Periodic meetings were held with all participants to discuss the operation and progress towards improved delivery. As of the end of 2006, the parties had developed a list of issues aimed to address the delivery performance. Issues under discussion included: 1) Curtailment and control of non-firm, third-party transactions; 2) Strategic phase angle regulator (PAR) tap moves for peak-load days and maintenance days; 3) Wheeling performance reporting, performance metrics and data access; and 4) Past performance and remedies. These items were expected to be completed in the first half of 2007. Table 4-6 shows the settlement values for 2006.[20]

The FERC order asked the market monitors for both PJM and NYISO to evaluate, during the protocol's initial six-month period, their ability to perform investigations ensuring that neither gaming nor abuse of market power occur. The PJM MMU concluded that there was no reason to gather data outside the bounds of the order.

In addition, the MMU has evaluated conduct under the protocol and has not identified the exercise of market power by either participant.

20 For monthly settlement values, see *2006 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions."

Interchange Transaction Issues

Loop Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow despite the fact that the system actual and scheduled flows could net to a zero difference.

Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

The fact that total PJM net actual interface flows were very close to net scheduled interface flows on average for 2006 as a whole is not a useful measure of loop flow. There were significant differences between scheduled and actual flows for specific individual interfaces. (See Table 4-7.) From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous control areas.

During 2006, for PJM as a whole, net scheduled and actual interchange differed by less than 2 percent. (See Table 4-7.) Actual system exports were 15.426 million MWh and so were less than the scheduled total exports of 15.699 million MWh by 0.273 million MWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 13.627 million MWh exceeding scheduled exports of 1.244 million MWh by 12.383 million MWh or 995 percent, for an average of 1.414 MW during each hour of the year. At the PJM/TVA Interface, net actual exports were less than scheduled exports by 9.916 million MWh or -97 percent. At the PJM/FE Interface, net actual imports exceeded scheduled exports by 7.715 million MWh or 214 percent. At the PJM/ALTE Interface, net scheduled exports were less than actual exports by 5.947 million MWh or 612 percent. At the PJM/NYIS Interface, net actual exports exceeded scheduled exports by 5.405 million MWh or 130 percent.

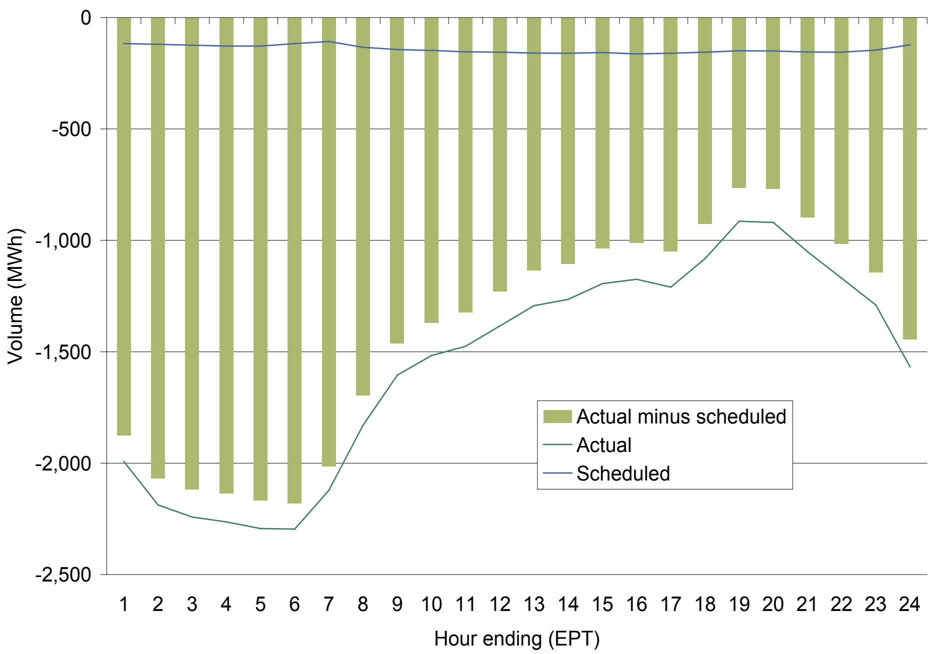
Table 4-7 Net scheduled and actual PJM interface flows (MWh x 1,000): Calendar year 2006

	Actual	Net Scheduled	Difference	Difference (Percent Net Scheduled)
ALTE	(6,918)	(971)	(5,947)	612%
ALTW	(3,067)	(956)	(2,111)	221%
AMRN	-	(1,034)	1,034	(100%)
CILC	1,209	(125)	1,334	(1067%)
CIN	4,268	452	3,816	844%
CPLE	4,632	383	4,249	1109%
CPLW	(1,966)	(857)	(1,109)	129%
CWLP	(631)	-	(631)	
DUK	(3,645)	1,229	(4,874)	(397%)
EKPC	502	(527)	1,029	(195%)
FE	4,113	(3,602)	7,715	(214%)
IP	2,461	1,553	908	58%
IPL	2,824	-	2,824	
LGEE	842	336	506	151%
MEC	(4,568)	(5,369)	801	(15%)
MECS	(13,627)	(1,244)	(12,383)	995%
NIPS	(2,604)	112	(2,716)	(2425%)
NYIS	(9,559)	(4,154)	(5,405)	130%
OVEC	11,214	10,411	803	8%
TVA	(260)	(10,176)	9,916	(97%)
WEC	(646)	(1,160)	514	(44%)
Total	(15,426)	(15,699)	273	(1.7%)

Loop Flows at the PJM/MECS and PJM/TVA Interfaces

As in 2005, the PJM/MECS Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight off-peak hours. (See Figure 4-13.) Generally, the PJM/MECS Interface is an exporting interface meaning that power flows from PJM to MECS. The actual exports exceeded the scheduled exports at that interface by an average of 2,000 MW per hour for those off-peak hours. The peak-hour difference between actual and scheduled exports averaged 1,121 MW.

Figure 4-13 PJM/MECS interface average actual minus scheduled volume: Calendar year 2006



The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows. The PJM/MECS differences and the PJM/TVA differences were in opposite directions. The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports. (See Figure 4-14 and Figure 4-15.) The consolidation of the former southeast and southwest pricing points in October 2006 has had an apparent impact at the PJM/TVA Interface.[21] Figure 4-14 shows the average hourly actual, scheduled flows and the difference between them for the preconsolidation time period January 1, 2006, through September 30, 2006. Actual exports were less than scheduled exports by 1,328 MWh every hour, on average. Postconsolidation, this difference decreased by 61 percent to 514 MW (on average) each hour. (See Figure 4-15.)

21 For a more detailed discussion of this issue, see *2006 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Loop Flows at PJM's Southern Interfaces."

Figure 4-14 PJM/TVA average flows: January 1 to September 30, 2006, preconsolidation

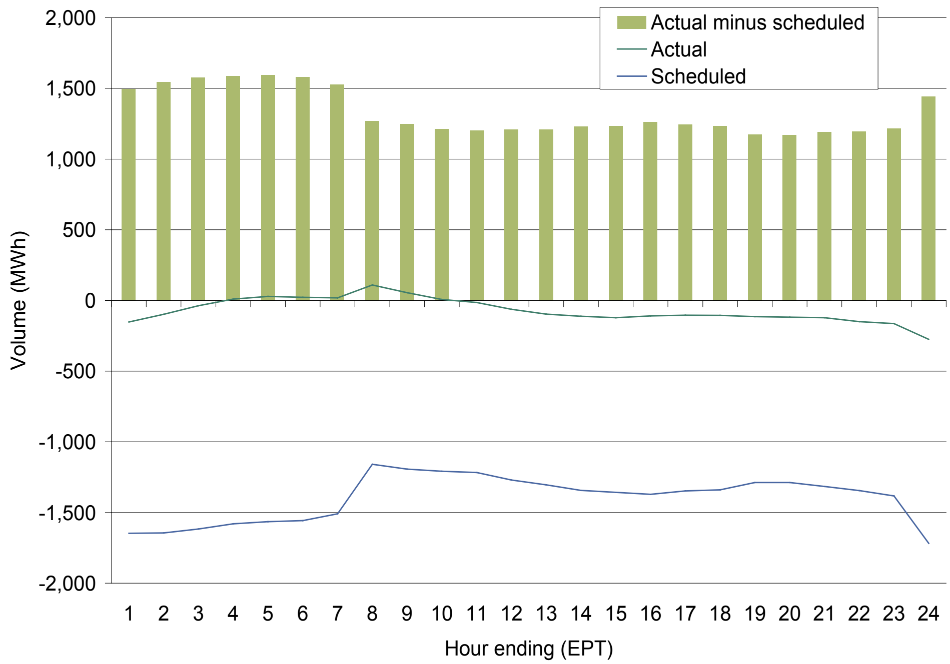
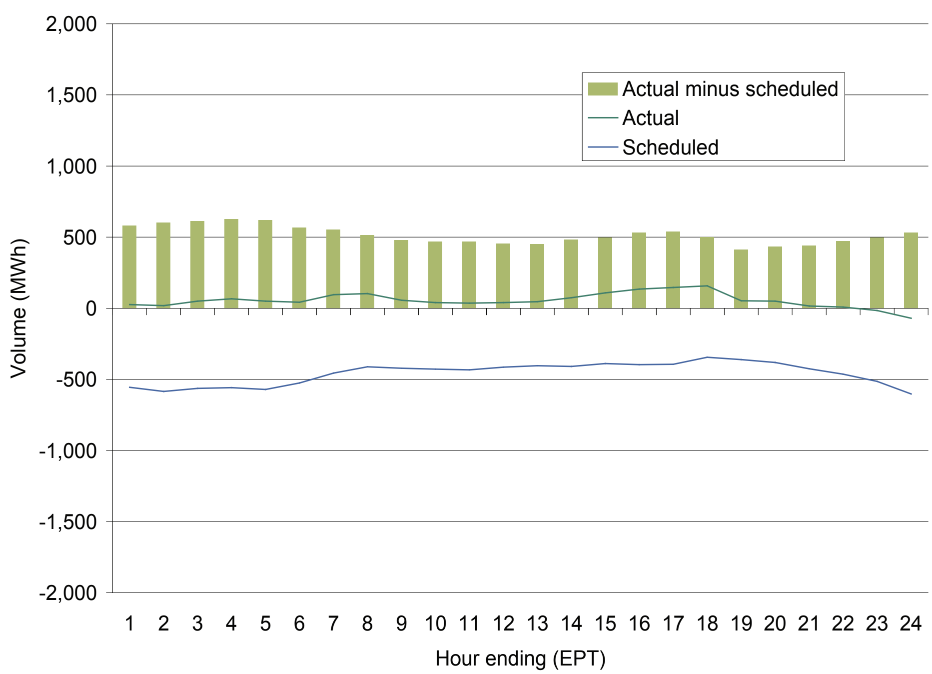


Figure 4-15 PJM/TVA average flows: October 1 to December 31, postconsolidation



Loop flows, measured as the differences between scheduled and actual flows at specific interfaces, are a significant concern. Loop flows have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear.

Loop Flows at PJM's Southern Interfaces

As Figure 4-16 and Figure 4-17 illustrate, there was a persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew larger through the summer. In the southwest for example, while actual flows at the PJM/TVA and PJM/EKPC Interfaces were relatively small exports, scheduled energy exports at these interfaces were very large. The scheduled exports increased further in June, July and August.

Figure 4-16 Southwest actual and scheduled flows: Calendar year 2006

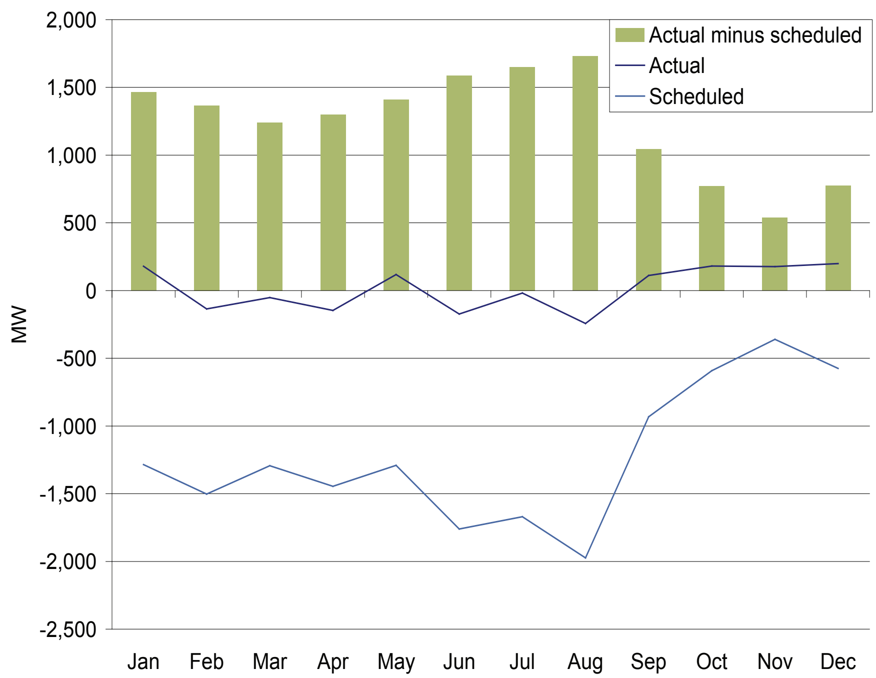
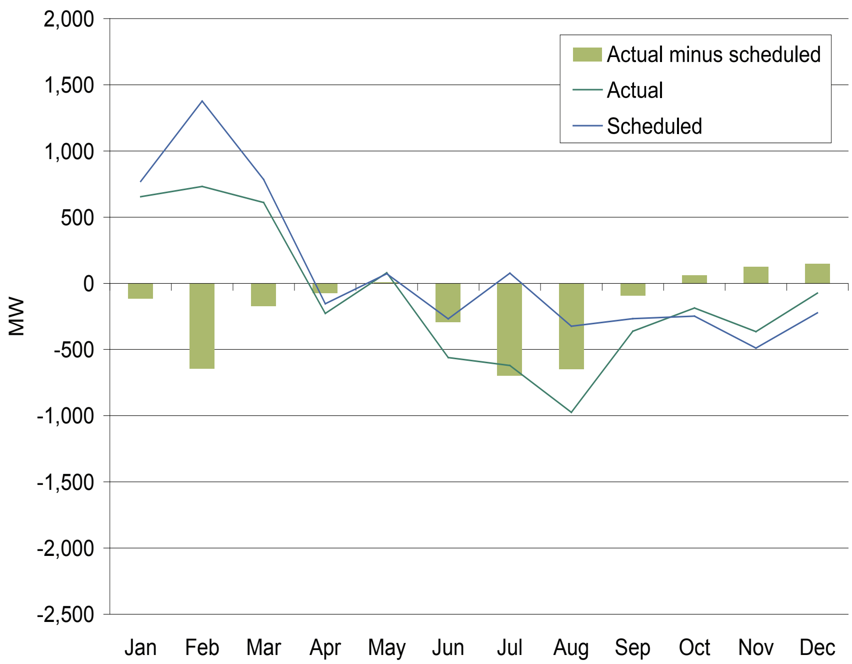
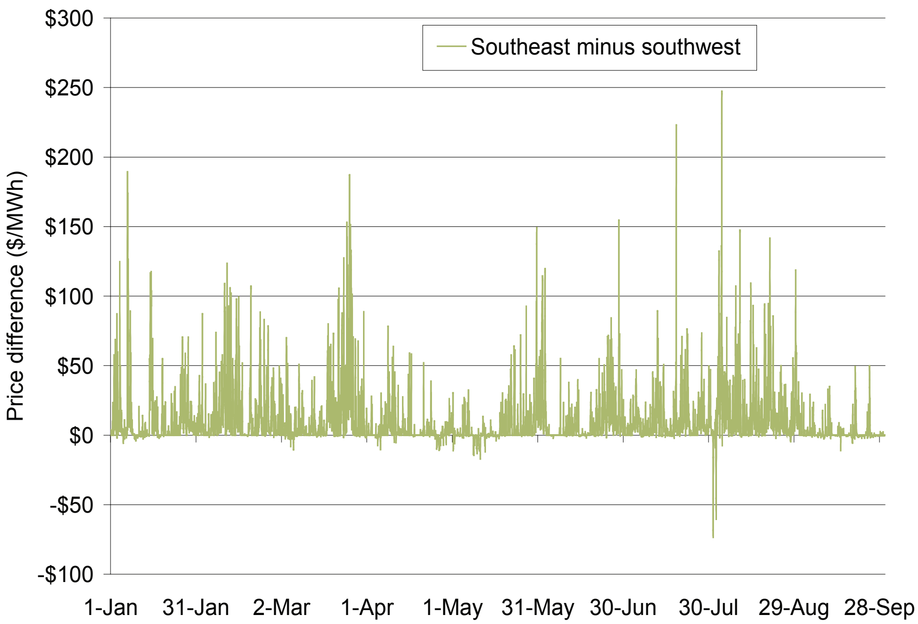


Figure 4-17 Southeast actual and scheduled flows: Calendar year 2006



The difference in price between the southeast and southwest pricing points provided incentives to schedule imports to receive the relatively higher southeast price and schedule exports to pay the lower southwest price on the export. (See Figure 4-18.)

Figure 4-18 Southeast minus southwest LMP: January to September 2006



For example, there were transactions from a source in the southeastern U.S. to a sink in the southwestern U.S. While the actual power flow took the path of least resistance directly from the source in the southeastern U.S. to the sink in the southwestern U.S., without ever flowing through PJM, the transaction was scheduled through PJM to take advantage of the pricing differential. There was a corresponding scheduled import transaction with a source in the southeast and a sink in PJM which was paid the southeast LMP as an import. Corresponding scheduled export transactions with a source in PJM and a sink in the southwest paid the southwest LMP as exports. The market participant which scheduled the transactions received the positive difference between the higher southeast LMP and the lower southwest LMP.

The average hourly price difference between the southeast and the southwest pricing points was $9.10 per MWh from January 1, 2006, through September 30, 2006. During that time period, 80 percent of the hours experienced a price differential. While PJM's prices provided an incentive to import at PJM's Southeast Interface and to export at PJM's Southwest Interface, scheduled flows, but not the corresponding actual flows, responded to the incentive. The result was false arbitrage that paid participants based on the scheduled flow despite the fact that the transactions did not provide power flows consistent with the incentive.

As a result of this developing pattern of behavior, it became clear that there was a need for additional modifications to the rules governing pricing for external transactions.[22] On August 31, 2006, PJM announced that, effective October 1, 2006, it would combine the southeast and southwest pricing points into a single

22 See "PJM Southeast and Southwest Interface Pricing Point Consolidation Approach" (August 31, 2006) (Accessed February 12, 2007) <http://www.pjm.com/committees/mrc/downloads/ 20060911-item-05-se-sw-interface--pricing-pts-consolidation.pdf > (23 KB).

south pricing point with different prices for imports and exports.[23] This change affects prices for external transactions scheduled for delivery to or delivery from control areas mapped to either the southwest or southeast interface pricing points. The rules governing the pricing of external transactions were first introduced on July 19, 2002, and were clarified in letters dated August 1, 2002, August 29, 2002, January 9, 2003, and February 24, 2003.

PJM determined that the associated transactions should receive a price more consistent with the associated power flows. PJM redefined the southeast and southwest pricing points. The PJM pricing points no longer include southwest or southeast but are: MISO; MICHFE; NIPSCO; Northwest; NYIS; Ontario IESO; OVEC; SOUTHIMP and SOUTHEXP. The SOUTHEXP interface pricing point consists of the buses that were included in the southwest and southeast interface pricing point definitions weighted by the tie line export power flow patterns. Some buses may have zero weights. The SOUTHIMP interface pricing point also consists of the buses that were included in the southwest and southeast interface pricing point definitions weighted by the tie line import power flow patterns. Again, some buses may have zero weights. As with all of PJM's external interfaces, these weights may be changed in the future to ensure the physical impact of transactions on the system is appropriately reflected in the pricing.[24] Changes in weights may occur periodically based on PJM's assessment of actual power flows. On October 4, 2006, when a PJM network model update was performed, one of the buses in the definitions was deleted and a replacement was added.

In order to reflect the actual flow of transactions associated with the southwest and southeast interface pricing points, on October 1, 2006, PJM began to price all transactions that source in PJM and sink in one of the relevant defined control areas, at the SOUTHEXP interface pricing point. Similarly, PJM has begun to price all transactions that sink in PJM and source in one of the defined control areas, at the SOUTHIMP interface pricing point. This enables PJM to price imports and exports differently based on their impacts on the PJM transmission system. The weighting of the buses included in these definitions may be adjusted to help ensure that the impacts of transactions on the transmission system are appropriately reflected in the resulting interface prices and, as such, the definitions are dynamic. PJM also has the ability to adjust bus weights for any of PJM's external interfaces. PJM monitors the flows and applies engineering judgment to determine when and if the weightings need to be adjusted.

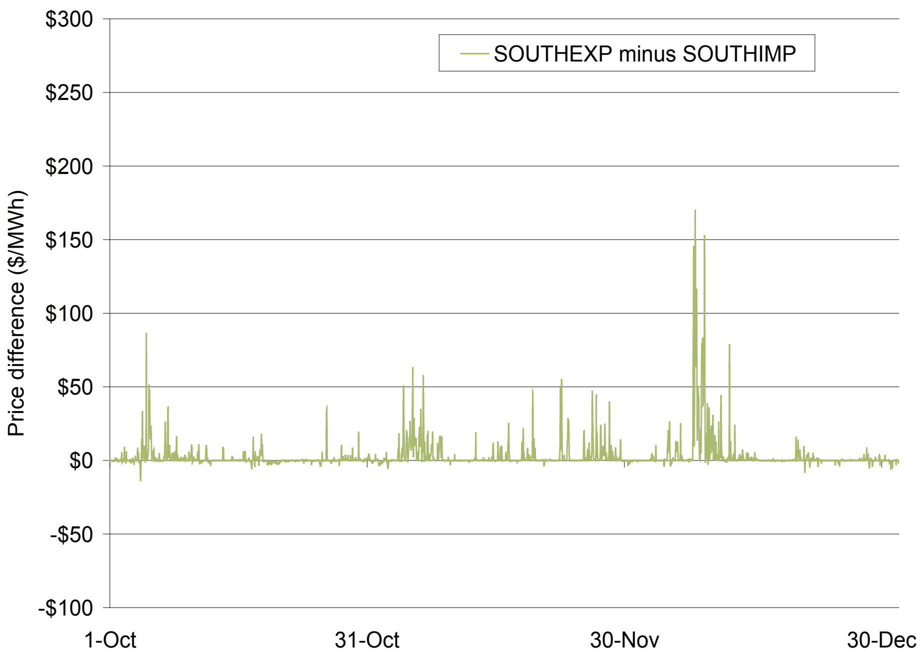
After the pricing point change, scheduled flows more closely matched actual flows, primarily as a result of reductions in scheduled flows while actual flows remained relatively unchanged. In particular, a significant level of scheduled exports to the southwest stopped after the modification of the pricing points. A small number of market participants had been regularly scheduling large exports and the decline in their scheduling activity was responsible for most of the improved convergence between actual and scheduled flows. In the southwest, average actual-minus-scheduled values peaked at about 1,700 MW per hour in August and dropped to 700 MW per hour in October. In the southeast, average actual-minus-scheduled values peaked at -674 MW in July and August and dropped to 60 MW per hour in September. The price difference between the new SOUTHEXP and SOUTHEXP prices is shown in Figure 4-19. It can be seen that when there is a difference, the SOUTHEXP price tends to be higher than SOUTHIMP. The average hourly difference

23 See "PJM Southeast and Southwest Interface Pricing Point Consolidation Approach August 31, 2006" (August 31, 2006) (Accessed January 8, 2007) <http://www.pjm.com/committees/ mrc/downloads/20060911-item-05-se-sw-interface--pricing-pts-consolidation.pdf> (23 KB).

24 See "PJM Interface Price Definition Methodology" (September 29, 2006) (Accessed January 8, 2007) <http:// www.pjm.com/markets/energy-market/downloads/20060929-interface-definition- methodology1.pdf> (33 KB).

is $2.88 per MWh over the October through December period. This price difference reflects the weighted bus components of the pricing point definitions. The nodal definition of SOUTHEXP was initially the same as the former southeast pricing point but, as a result of changes to the component bus weights, that is no longer the case. While the revised pricing is a clear improvement, the dynamic weighting may not provide the appropriate price signal to potential imports at the southeastern PJM interfaces that might help relieve congestion. PJM has offered the option to dynamically schedule units in order to ensure a match between the price and energy flows.[25]

Figure 4-19 SOUTHEXP minus SOUTHIMP LMP: October to December 2006



Data Required for Full Loop Flow Analysis

A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The term non market area is a misnomer in the sense that all electricity transactions are part of the broad energy market in the Eastern Interconnection. There are areas with transparent markets and there are areas with less transparent markets, but these areas together comprise a market and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flow.

25 A dynamically scheduled unit is a unit that is physically outside of the PJM footprint yet is treated as if it were located inside the footprint. PJM's network model can calculate an LMP at the bus for units located outside of PJM and validate that such units respond to the PJM price signal by increasing or decreasing output. Such units receive the calculated, unit-specific LMP based on the actual value of changes in the unit's output to PJM.

Data on both scheduled flows and actual flows are required in order to analyze loop flows. The data to fully analyze loop flows affecting PJM are not currently available to PJM. Scheduled flow data for transactions that touch PJM are available, but scheduled flow data for transactions that affect PJM but do not explicitly touch PJM are not available to PJM. These data exist in the form of NERC Tag data in an application developed by Open Access Technology International, Inc. (OATI) for NERC. In order to get access to all relevant Tag data on an ongoing basis, PJM would need to get permission from each control area (CA) in the Eastern Interconnection. PJM has reached agreements with the Midwest ISO, the Ontario IESO, NYISO and TVA to get a snapshot of such data for a defined historical period and has received such data. Even this limited effort required a lengthy process.

Actual flow data for generation and transactions that originate outside PJM, but affect PJM are not currently available to PJM. In order to get access to relevant actual flow data, PJM would need to get access to metered flow on relevant flowgates from each CA in the Eastern Interconnection. PJM has reached such an agreement with the Midwest ISO and is in discussions with a limited number of other CAs.

Wisconsin Public Service Corporation (WPS) Complaint

On August 15, 2006, the Wisconsin Public Service Corporation (WPS) filed a complaint against PJM and the Midwest ISO at the FERC requesting that the FERC direct PJM and Midwest ISO (the RTOs) to promptly institute joint unit commitment and dispatch over the entire PJM/MISO footprint.[26] WPS asserted that PJM and Midwest ISO commit to creating joint commitment and dispatch, but that their efforts to do so fell short. WPS asserted that the cost-benefit analysis performed by the RTOs showed that there is clear benefit to a single market dispatch and that this estimate of benefit is conservatively low. WPS argued that the failure to implement a joint commitment and dispatch has denied the public approximately $50 million per year of production cost savings and probably significantly more.

The primary evidence adduced by WPS was a comparison of prices at the PJM/MISO border and a comparison of RTO shadow prices for certain flowgates. WPS claimed that the observed difference in prices at the border and in shadow prices reflects a failure of PJM and Midwest ISO to integrate their markets.

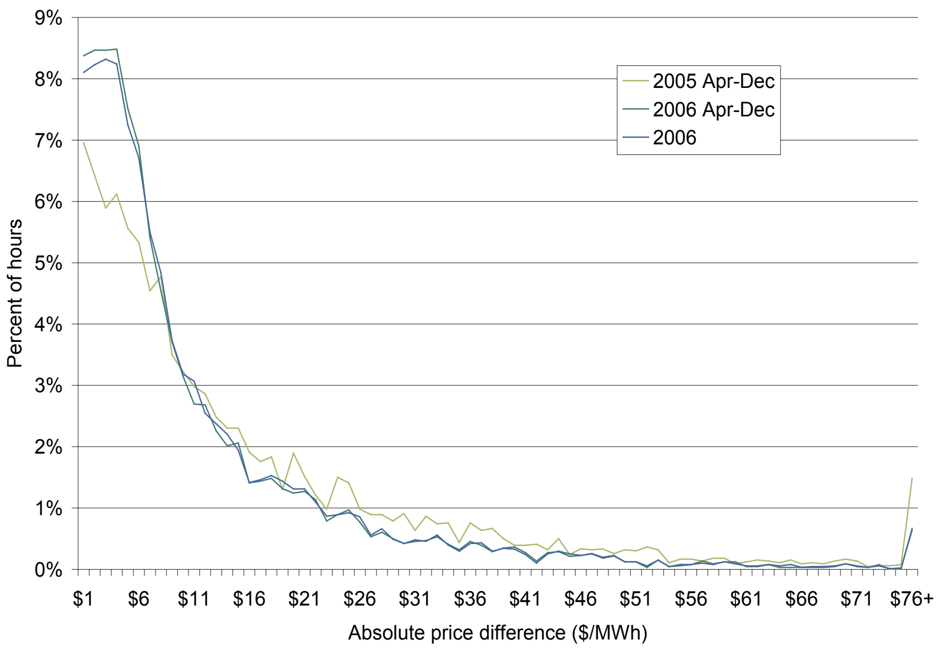
The RTOs responded that an appropriate cost-benefit analysis does not justify joint dispatch at the present time.[27] Nonetheless the RTOs recognize that there are actions that can be taken to address the lack of convergence of shadow prices. While shadow prices are internally consistent, when one RTO has no redispatch options, shadow prices in that RTO do not reflect the redispatch options of the other RTO. The RTOs are developing an approach to improve shadow price convergence. The RTOs believe that benefits can be achieved via less costly initiatives and that only after these are implemented and their impact assessed should incremental costs and benefits of joint dispatch be considered.

Figure 4-20 shows the hourly absolute differences between the MISO/PJM and PJM/MISO border prices. Three time periods are displayed in the figure including April to December 2005 (Midwest ISO market operation in 2005), the same period for 2006 and the full year, 2006. The curves show a shift to lower differences in both 2006 time periods when compared to the 2005 period.

26 WPS Complaint Requesting a MISO/PJM Joint and Common Market, Complaint, Docket No. EL06-97 (August 15, 2006).

27 Answer of the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., Response, Docket No. EL06-97 (September 15, 2006).

Figure 4-20 Absolute LMP difference of PJM and MISO border prices



Ramp Reservation Rule Change

PJM limits the amount of change in net interchange within 15-minute intervals in order to ensure compliance with NERC performance standards. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. The change in net interchange is referred to as ramp. Any market participant wishing to initiate (or change) a transaction must obtain a ramp reservation. PJM issues reservations, on a first come, first served basis, up to the ramp limit.

While ramp limits may be modified by PJM depending on system conditions, the limit is generally +/- 1,000 MW. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15-minute period would not exceed 1,000 MW in either direction.

Market participants at times request and receive ramp reservations that are not actually used for an energy transaction. When this happens, other market participants can be prevented from obtaining ramp reservations. In addition, the sudden, last-minute cancellation of large transactions can create significant impacts on PJM operations and markets as internal PJM resources have to make up any difference between actual and expected energy in PJM. This behavior (reserving but not using ramp) can reflect attempts to manipulate PJM prices, attempts to disadvantage competitors, mistakes by participants or the unanticipated failure to complete the underlying transaction. To help ensure efficient use of available ramp, PJM's former rules forced unused ramp reservations to expire 30 minutes before they were scheduled to flow if they were not backed up with an actual energy transaction. That left only 10 minutes for another participant to assemble a transaction and request the ramp because PJM rules required that transactions be submitted only up to 20 minutes prior to the scheduled start time for hourly transactions.[28] Given that it requires time to assemble the components of a transaction, the rule freed unused ramp when it was frequently too late for other market participants to make effective use of it. In other words, ramp reservations became available with too little time for others to use them and therefore did not prevent participants from effectively blocking other participants from the market.

In early 2006 the number of market participant complaints regarding this inability to obtain ramp in a timely manner and complaints about large ramp volume swings became more persistent. Ramp reservations were expiring unused at an increasing rate. (See Figure 4-21.) The MMU's effort to identify and contact participants resulted in improved behavior, but similar efforts in the past, while achieving the desired results, had only temporary effects. As a result, and as contemplated in the *2005 State of the Market Report*, the MMU developed, PJM proposed, and the membership agreed, to changes in the ramp reservation rules to impose limits on the time that a ramp reservation could be held without an associated energy schedule. These changes became effective on August 7, 2006.

Figure 4-21 Number of PJM automatic ramp reservation denials by month: January 2005 to July 2006

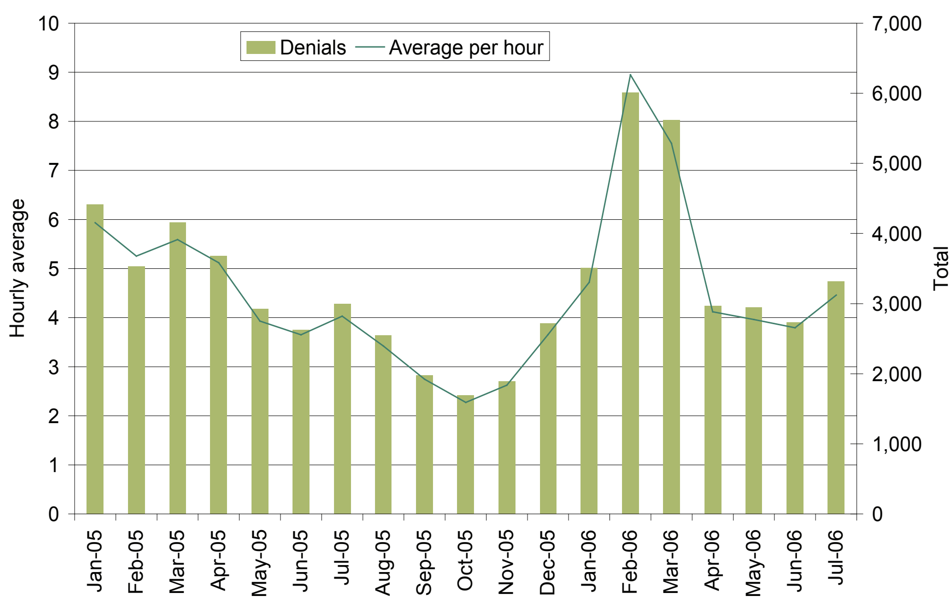


Figure 4-22 shows the results of the rule change. Under the new rule, ramp reservations expire (unless used) at the conclusion of a defined time interval that starts when a reservation is approved. This results in a distributed pattern of expirations in the time before the deadline for scheduling a transaction (20 minutes prior to flow). The actual distribution pattern of expirations since the rule change is shown in Figure 4-22.

28 See PJM "Manual 11: Scheduling Operations" (August 11, 2006), p. 103 (Accessed January 8, 2007) <http://www.pjm.com/contributions/pjm-manuals/pdf/m11.pdf > (823 KB).

For reference, Figure 4-22 also indicates when reservations would have expired under the old rule. Previously, all unused reservations expired at the same time, 30 minutes prior to flow. The distributed nature of automatic expirations under the new rule allows participants to obtain expired reservations in a more timely manner than was previously possible.

Figure 4-22 Distribution of expired ramp reservations in the hour prior to flow [old rules (theoretical) and new rules (actual)]: October to December 2006

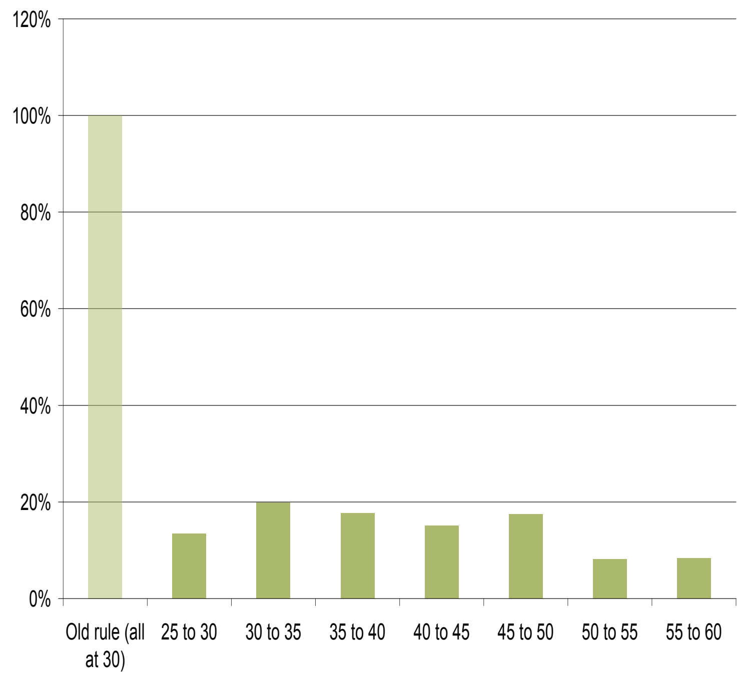


Figure 4-23 presents an actual example of how the old rule worked. These data are for flow to start at 1000 hours on April 19, 2006. Figure 4-24 takes the same data and applies the new rule. As seen in the oval highlighted area of Figure 4-23, 10 reservations were all automatically denied at the same time (0930) and one was withdrawn at the last minute (0929) by the market participant. At 0918 export ramp became unavailable. The import and export ramp were impacted by the volumes held in each reservation and export ramp was not available to other participants until 0930. In Figure 4-24 the same reservation data are used, but the new rules are applied. With the new rules, only one reservation was denied at 30 minutes prior to flow compared to the group of reservations denied under the old rule. Each of the other remaining 10 reservations was, as would have happened under the old rule, denied under the new rules. However under the new rules the denials occurred at the end of their individual wait periods rather than simultaneously at 30 minutes prior to flow. This had the effect of freeing up ramp sooner and with less volatility than would have been the case under the old rule. Note that at 0918, a time of high reservation activity, export ramp became available in contrast to the prior case.

Figure 4-23 Partial ramp history for April 19, 2006, hour beginning 1900

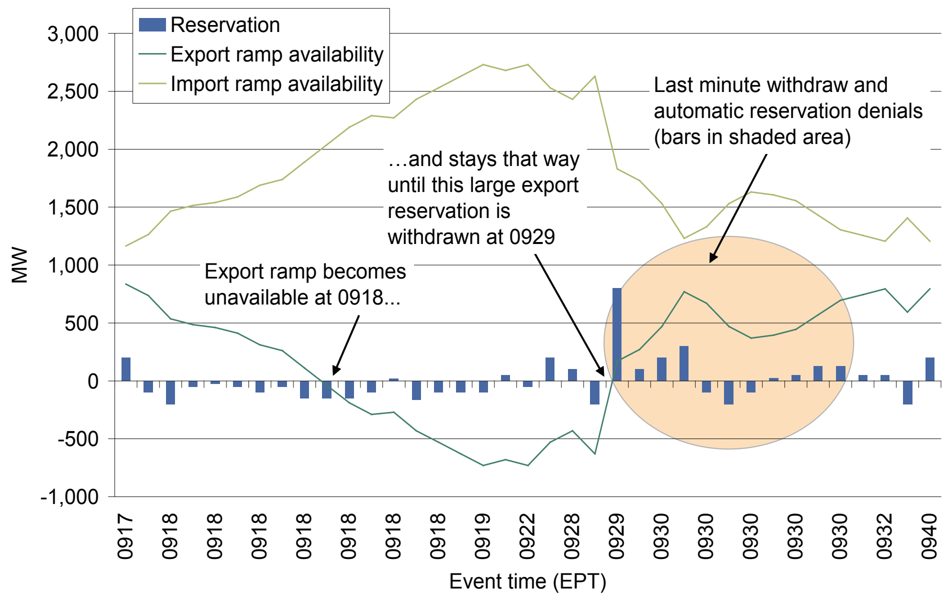
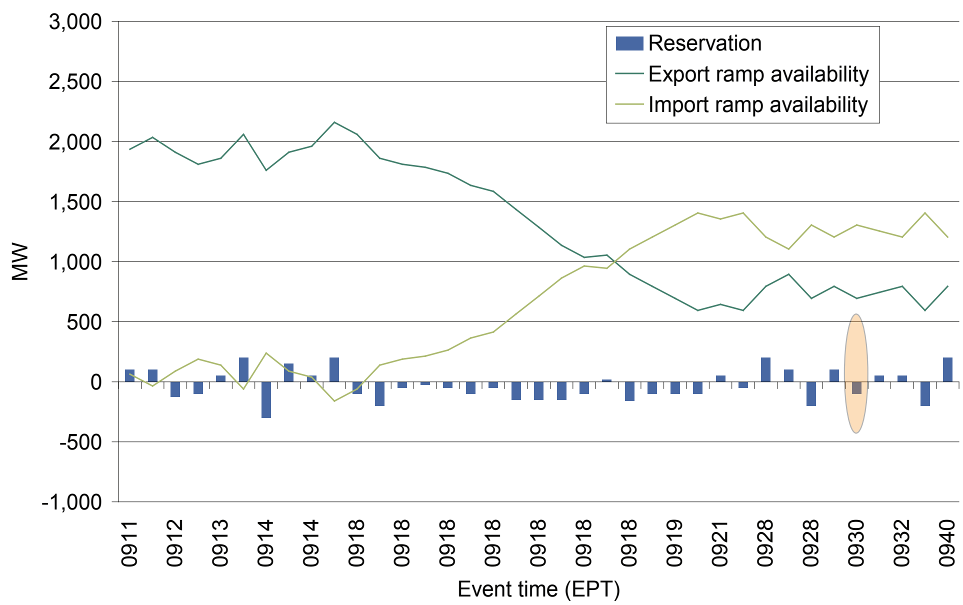


Figure 4-24 Partial ramp history for April 19, 2006, hour beginning 1900 modified to reflect theoretical application of new rule



When a reservation is made within 60 minutes of the time of flow, the new rule allows 10 minutes from the time the ramp reservation is approved for a participant to put a corresponding energy schedule into the system. If an energy schedule is not put into the system within that period, the ramp reservation is denied and the associated ramp is made available to others. This rule structure allows for unused ramp to become available to others in a more timely manner. Instead of large amounts of unused ramp becoming available at a fixed time (30 minutes prior to flow) with little time remaining to use it, unused ramp becomes available sooner and in a more evenly distributed manner.

After a reservation is made, if an energy schedule is not submitted in a timely manner, based on a sliding timescale ranging from 10 minutes to 90 minutes depending on how far in advance the request is made, the reservation is automatically denied. Table 4-8 shows these new timing requirements. Additionally, participants can now put their reservation request “in queue” if there is no ramp available at the time of their request. Reservations with the “in queue” status will be the first to receive any ramp that may become available and will be approved on a requested, timestamp basis.

Table 4-8 Timing requirements of new ramp reservation rule

	Pending Tag Reservations	
Reservation Duration	Time before Start of Reservation Submitted	Length of Time to Hold Reservation
<= 24 Hours	<= 1 Hour	10 Minutes
<= 24 Hours	> 1 Hour and < 4 Hours	15 Minutes
< 24 Hours	>= 4 Hours	90 Minutes
>= 24 Hours	Any Time	90 Minutes
	In-Queue Reservations	
Reservation Duration	Time before Start of Reservation Submitted	Maximum Length of Time in Queue
<=24 Hours	Any Time	Until 30 Minutes prior to the Start of the Reservation
> 24 Hours	Any Time	Until 5 Hours prior to the Start of the Reservation

While the implemented rule change has had a positive effect, the MMU will continue to monitor the reservations and use of ramp. There are also additional issues associated with ramp that remain to be addressed. As an example, PJM rules permit the potential artificial creation of ramp room in one direction using a ramp reservation in the opposite direction of that desired. For example, a market participant who wishes to initiate an import transaction when there is no available import ramp, requests a ramp reservation in the exporting direction. When accepted, this reservation creates apparent import ramp. The participant would also request an import reservation. Ultimately, the import transaction would flow and the export reservation would not be used to export energy, expiring after its time limit.

SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must own or acquire capacity resources to meet its capacity obligations. Load-serving entities (LSEs) can acquire capacity resources by entering into bilateral agreements, by participating in the PJM-operated Capacity Credit Market (CCM) or by constructing generation. LSEs can reduce their capacity obligations by participating in relevant demand-side response programs. Collectively, all arrangements by which LSEs acquire capacity are known as the Capacity Market.[1]

The PJM Capacity Credit Market[2] provides mechanisms to balance supply of and demand for capacity unmet by the bilateral market or self-supply. The PJM Capacity Credit Market consists of the Daily, Interval,[3] Monthly and Multimonthly CCM. The PJM CCM is intended to provide a transparent, market-based mechanism for retail LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. The PJM Daily CCM permits LSEs to match capacity resources with short-term shifts in retail load while the Interval, Monthly and Multimonthly CCMs provide mechanisms to match longer-term obligations with capacity resources.

In June 2007, it is expected that the current capacity market construct will be replaced with the Reliability Pricing Model (RPM) capacity market construct.

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.[4]

From June 2004 through May 2005, a separate ComEd capacity credit market had operated under PJM rules, but with capacity obligations and capabilities measured in installed MW. That changed on June 1, 2005, when all ComEd capacity markets became fully integrated into the PJM capacity marketplace. To analyze PJM Capacity Market performance during 2006 as compared to 2005, the *2006 State of the Market Report* limits the relevant 2005 period to the one that started on June 1, 2005, and ended on December 31, 2005, when all capacity became measured by unforced MW. The report refers to it as the 2005 ComEd post capacity integration (PCI) period (i.e., the 2005 ComEd PCI period).[5]

1 See *2006 State of the Market Report,* Volume II, Appendix K, “Glossary,” for definitions of PJM Capacity Credit Market terms.

2 All PJM Capacity Market values (capacities) are in terms of unforced MW.

3 PJM defines three intervals for its Capacity Market. The first interval extends for five months and runs from January through May. The second interval extends for four months and runs from June through September. The third interval extends for three months and runs from October through December.

4 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.”

5 For further information on the ComEd PCI period, see *2006 State of the Market Report,* Volume II, Appendix E, “Capacity Market.”

Overview

Market Structure

- **Supply.** Unforced capacity remained relatively constant in the PJM CCM in 2006 compared to the 2005 ComEd PCI period. Average unforced capacity decreased by 298 MW or 0.2 percent to 152,482 MW. Capacity resources exceeded capacity obligations every day by an average of 9,531 MW, a decrease of 466 MW from the average net excess of 9,997 MW for the 2005 ComEd PCI period.

- **Demand.** Unforced obligations remained relatively constant in the PJM CCM in 2006 compared to the 2005 ComEd PCI period. Average load obligations increased by 168 MW or 0.1 percent to 142,951 MW. PJM electricity distribution companies (EDCs) and their affiliates maintained a large market share of load obligations in the PJM CCM in 2006, together averaging 87.6 percent, down slightly from 88.5 percent for the 2005 ComEd PCI period.

- **Market Concentration.** Structural analysis of the PJM CCM found that, on average, the Daily CCM exhibited moderate concentration levels while the Monthly and Multimonthly CCM exhibited high concentration levels during 2006. The highest market share for any entity in one daily auction was 44.9 percent, while the highest average daily market share for any entity across all of the daily auctions was 28.8 percent. Of 365 daily auctions, 82 (22.5 percent) had a Herfindahl-Hirschman Index (HHI) greater than 1800. HHIs for the longer-term Monthly and Multimonthly CCM averaged 3611, with a maximum of 10000 and a minimum of 1691 (three firms with equal market shares would result in an HHI of 3333). The highest market share for any entity in one monthly/multimonthly auction was 100.0 percent, while the highest average market share for any entity across all of the monthly/multimonthly auctions was 30.5 percent. All but one of the 65 monthly/multimonthly auctions (98.5 percent) had an HHI greater than 1800. The PJM CCM accounted for 6.4 percent of total capacity obligations. The PJM Market Monitoring Unit (MMU) also analyzed ownership in the PJM Capacity Market as a whole in order to develop a more complete assessment of market structure for capacity. Ownership in the PJM Capacity Market exhibited low concentration levels throughout the year, with HHIs at 925 on January 1 and December 31. The highest market share declined from 16.7 percent to 16.4 percent. There was a single pivotal supplier throughout the year, with four individual suppliers who were each pivotal on a stand-alone basis.

- **External and Internal Capacity Transactions.** In 2006, imports averaged 3,093 MW, which was a decrease of 904 MW or 22.6 percent from the 2005 ComEd PCI period average of 3,997 MW. Exports averaged 4,958 MW, which was a decrease of 74 MW or 1.5 percent from the 2005 ComEd PCI period average of 5,032 MW. Average net exchange decreased 830 or 80.2 percent to -1,865 MW from the 2005 ComEd PCI period average of -1,035 MW. Internal bilateral transactions averaged 160,952 MW, which was an increase of 4,581 MW or 2.9 percent from the 156,371 MW average for the 2005 ComEd PCI period.

- **Active Load Management (ALM).** In 2006, ALM credits in the PJM CCM averaged 1,828 MW, down 214 MW (10.5 percent) from 2,042 MW in the 2005 ComEd PCI period.

Market Performance

- **CCM Volumes and Prices.** During 2006, total PJM CCM transactions averaged 9,118 MW (6.4 percent of obligation), which was 2,113 MW higher than the 2005 ComEd PCI period average of 7,005 MW (4.9 percent of obligation). Total PJM CCM prices averaged $5.73 per MW-day, which was $0.46 per MW-day higher than the 2005 ComEd PCI period average of $5.27 per MW-day. Daily CCM volume declined from 2.5 percent of average obligation in 2000 to 2.1 percent in 2006. Monthly and multimonthly CCM volume increased from 3.0 percent of obligation in 2000 to 4.3 percent of average obligation in 2006. CCM prices increased from 1999 through 2001 and have declined and remained relatively stable since 2001 with the exception of the summers of 2004 and 2006 and the first few days of January 2006.

Generator Performance

The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. These incentives are somewhat attenuated in the current capacity market design. The Energy Market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high. If they are successful, this will also result in lower forced outage rates. The design of the RPM provides additional incentives for reduced outages during high-load periods and scarcity pricing could also provide strong, complementary incentives for reduced outages during high-load periods.

From 2002 to 2004, the average PJM equivalent demand forced outage rate (EFORd) increased, from 5.4 percent in 2002 to 6.7 percent in 2003 and 7.3 percent in 2004.[6] In 2005, the average PJM EFORd decreased to 6.6 percent and again decreased in 2006 to 6.4 percent. The decrease in EFORd from 2005 to 2006 was the result of decreased forced outage rates across all unit types with the exception of steam and diesel generators. These forced outage rates are for the entire PJM Control Area.[7]

Conclusion

Perhaps the most important fact about the PJM Capacity Market is that it will change significantly in 2007 as the result of the implementation of the RPM capacity market design. The conclusions here are based both on the details of the capacity market structure, conduct and performance under the existing market designs and on the underlying facts about the ownership structure of capacity and the obligations of load. While the detailed conclusions apply primarily to the existing capacity market design, there are significant conclusions that apply to any capacity market design.

The MMU analyzed market structure and market performance in the PJM Capacity Market for calendar year 2006, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of

6 As a general matter, the annual EFORd data presented in state of the market reports may be revised based on final data submitted after the publication of the reports.

7 In some cases, data for the AEP, DAY, DLCO, Dominion and ComEd Control Zones may be incomplete for the years 2002 and 2003. Only data that have been reported to PJM were used.

nonaffiliated LSEs, the capacity-deficiency penalty structure facing LSEs, supplier knowledge of the penalty structure and supplier knowledge of aggregate market demand if not individual LSE demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is endemic to the existing structure of the PJM Capacity Market.

The RPM capacity market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective and explicitly limiting the exercise of market power.

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. This is the case for the existing capacity market design as well as for the RPM. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to or slightly above the demand for capacity. Demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal. In PJM, in 2006, the excess supply was 9,531 MW. There were four individual suppliers who were each larger than 9,531 MW and who were, therefore, each pivotal on a stand-alone basis. In other words, the market design for capacity leads, almost unavoidably, to structural market power. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load-serving entities to purchase a share of the capacity required to provide that reliability. But, it is important to keep these basic facts in mind when designing and evaluating capacity markets. The capacity market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.[8]

The analysis of capacity markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis also examines participant behavior in the context of market structure. In a competitive market structure, market participants are constrained to behave competitively. In a competitive market structure, competitive behavior is profit maximizing behavior. Finally, the analysis examines market performance results. The actual performance of the market, measured by price and the relationship between price and marginal cost, results from the interaction of these elements. For example, at times market participants behave in a competitive manner even within a noncompetitive market structure. This may result from the relationship between supply and demand and the degree to which one or more suppliers are singly or jointly pivotal. This may result from the short-run, net position of individual suppliers with structural market power. This may also result from a conscious choice by market participants to behave in a competitive manner based on perceived regulatory scrutiny or other reasons, even when the market structure itself does not constrain behavior.

8 The market could be competitive if there were many more suppliers and all were relatively small compared to the size of the market and the level of excess capacity, but this is unlikely to occur.

The MMU found serious market structure issues, but no exercise of market power in the PJM Capacity Market. The behavior of market participants in the context of the market structure and the supply and demand fundamentals offset these market structure issues in the PJM Capacity Market in 2006. The PJM Capacity Market results were competitive during 2006.

The new RPM capacity market design represents a significant advance over the current capacity market design because RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct appears consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The MMU recommends the implementation of the rules included in PJM's filed RPM Tariff to stimulate competition, to provide direct incentives for performance, to provide locational price signals, to provide forward auctions to permit competition from new entrants and to incorporate explicit market power mitigation rules. The RPM capacity market design explicitly provides that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve that design objective and explicitly limits the exercise of market power via the application of the three pivotal supplier test.

Market Structure

The MMU analyzed sources of supply of and demand for capacity, market concentration in the PJM CCM and the PJM Capacity Market, internal and external bilateral capacity transactions and ALM activity.

Supply

System net excess capacity can be determined using unforced capacity, capacity obligation, the sum of members' excesses and the sum of members' deficiencies. Table 5-1 and Figure 5-1 present these data for 2006.[9] Unforced capacity includes capacity imports and exports. Net excess is the net pool position, calculated by subtracting total capacity obligation from total capacity resources. Since total capacity obligation includes expected total load plus a reserve margin, a pool net excess position of zero is consistent with established reliability objectives.

The amount of capacity resources in PJM on any day reflects the addition of new resources, the retirement of old resources and the importing or exporting of capacity resources. These daily changes are functions of market forces. The total pool capacity obligation is set annually via an administrative process. During 2006, unforced capacity and obligations remained relatively constant in the PJM Capacity Market as compared to the 2005 ComEd PCI period.[10] Average unforced capacity decreased by 298 MW from 152,780 MW to 152,482 MW, a decrease of 0.2 percent. Average load obligations increased 168 MW or 0.1 percent from 142,783 MW to 142,951 MW. During this period, capacity resources exceeded capacity obligations in PJM on every day and the daily average net excess was 9,531 MW (6.7 percent of average obligation), a decrease of 466 MW from the average net excess of 9,997 MW for the 2005 ComEd PCI period (7.0 percent of average obligation).

9 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.

10 Data for this period are presented in the *2006 State of the Market Report,* Volume II, Appendix E, "Capacity Market."

Table 5-1 PJM capacity summary (MW): Calendar year 2006

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	162,571	349	162,008	163,097
Unforced Capacity	152,482	186	152,176	152,887
Obligation	142,951	121	142,461	143,152
Sum of Excess	9,531	205	9,037	10,047
Sum of Deficiency	0	0	0	0
Net Excess	9,531	205	9,037	10,047
Imports	3,093	201	2,769	3,333
Exports	4,958	404	4,401	5,668
Net Exchange	(1,865)	560	(2,616)	(1,114)
Unit-Specific Transactions	15,548	504	14,694	16,044
Capacity Credit Transactions	145,404	3,742	140,345	155,060
Internal Bilateral Transactions	160,952	3,543	155,750	170,680
Daily Capacity Credits	3,013	332	2,268	3,962
Monthly Capacity Credits	1,572	382	996	2,067
Multimonthly Capacity Credits	4,533	1,154	2,484	5,783
All Capacity Credits	9,118	1,424	7,103	11,720
ALM Credits	1,828	180	1,642	2,042

Figure 5-1 Capacity obligation for the PJM Capacity Market: Calendar year 2006

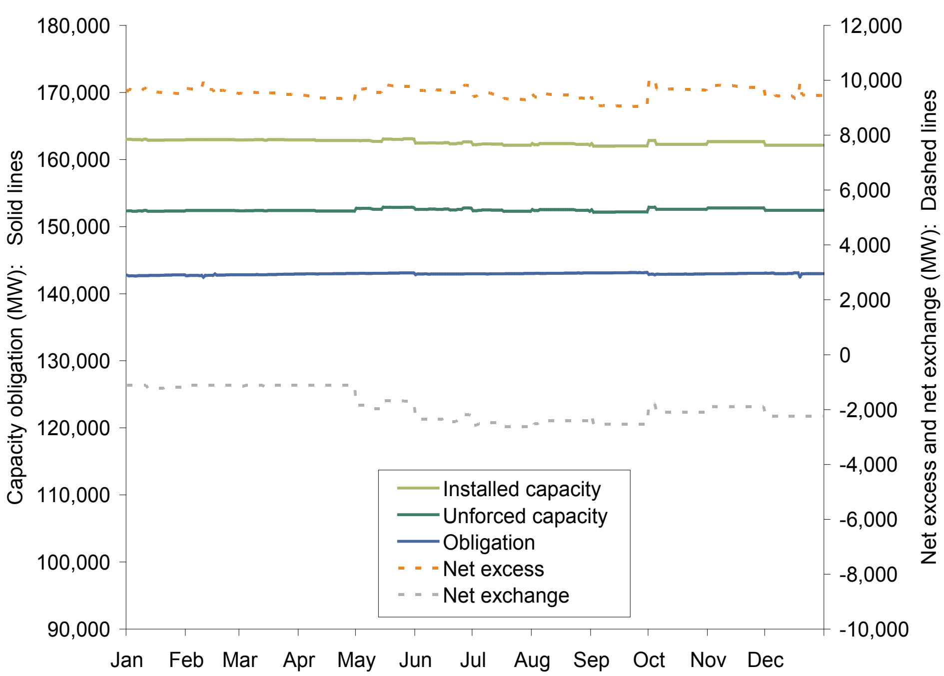
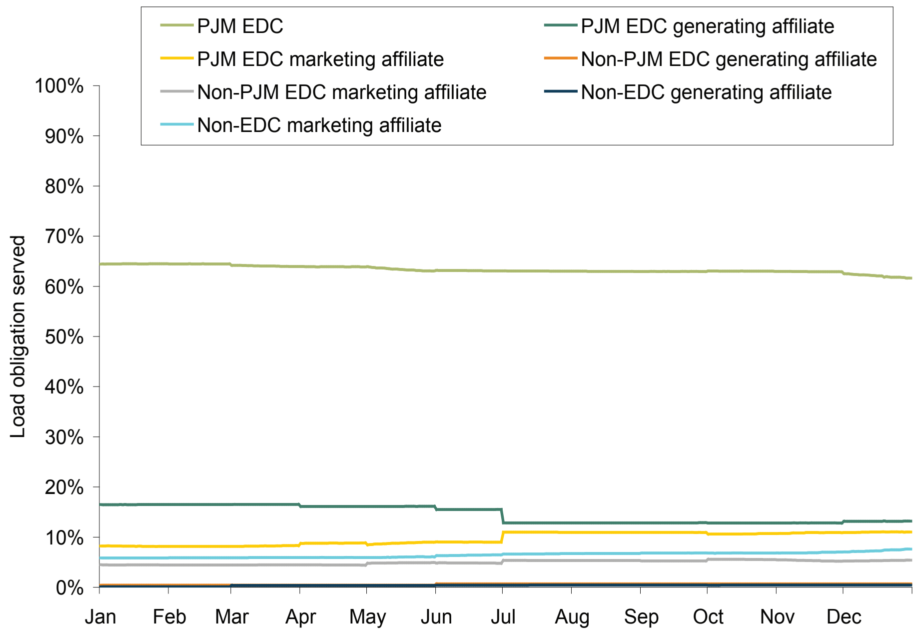


Figure 5-2 PJM Capacity Market load obligation served (Percent): Calendar year 2006



Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.

- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.

- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

During 2006, PJM EDCs and their affiliates maintained a large market share of load obligations in the PJM Capacity Market, together averaging 87.6 percent (See Figure 5-2 and Table 5-2.), down slightly from 88.5 percent for the 2005 ComEd PCI period. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates averaged 12.4 percent, up from 11.5 percent for the 2005 ComEd PCI period.

Load-serving entities can meet their load obligations through self-supply,[11] the PJM CCM or bilateral contracts with third parties. As shown in Table 5-3, Table 5-4 and Table 5-5, reliance on these options varied by market sector.[12] During 2006, PJM EDCs, some of which still owned generating assets (although as a whole not enough to meet their load obligations), self-supplied an average of 56.7 percent of their load obligations with their remaining obligations being supplied through bilateral contracts with third parties (45.8 percent) and the PJM CCM (-0.1 percent). The self-supply percentage is up from the 2005 ComEd PCI period value of 56.0 percent, while the bilateral contract percentage also increased from 45.6 percent for the 2005 ComEd PCI period. In 2006, entities in this sector, on average, purchased more capacity credits in the PJM CCM or through bilateral contracts with third parties than were required to meet their obligation, resulting in an average net excess of 2,171 MW (2.4 percent of obligation) as compared to a 2005 ComEd PCI period average net excess of 2,268 MW (2.1 percent of obligation) for this sector.

In the 2005 ComEd PCI period and in 2006, all generating affiliate sectors owned more capacity than their load obligations, were net capacity credit sellers in either the PJM CCM or through bilateral contracts and remained in higher net excess positions as a percentage of load obligations than the other sectors. All marketing affiliates, each of which was a net capacity credit buyer in either the PJM CCM or through bilateral contracts, bought slightly more capacity credits than required to meet their obligation and were in lower net excess positions than the other sectors in both periods. Volumes and percentages of load obligations for self-supply, the CCM and bilateral contracts for all generating affiliate and marketing affiliate sectors were approximately the same for the 2005 ComEd PCI period and for 2006.

11 Self-supply is defined as the unforced MW of the units owned by an entity.

12 Negative values in the "Capacity Credit Market" and in the "Net Bilateral Contracts" columns mean that a sector sold more capacity credits than it purchased for the relevant time period. A positive number means that a sector purchased more capacity credits than it sold for the relevant time period.

Table 5-2 PJM capacity market load obligation served: Calendar year 2006

	Average Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Jan	92,037	23,520	11,694	606	6,374	144	8,361	142,736
Feb	92,032	23,553	11,653	606	6,336	157	8,419	142,756
Mar	91,519	23,617	11,763	606	6,372	534	8,453	142,864
Apr	91,367	23,029	12,580	606	6,369	534	8,488	142,973
May	90,688	23,075	12,586	607	6,963	534	8,607	143,060
Jun	90,230	22,162	12,877	1,005	6,923	610	9,131	142,938
Jul	90,138	18,361	15,693	1,006	7,649	616	9,515	142,978
Aug	90,104	18,375	15,673	1,006	7,630	618	9,651	143,057
Sep	90,115	18,400	15,663	1,006	7,548	618	9,771	143,121
Oct	90,069	18,319	15,200	1,003	7,951	617	9,754	142,913
Nov	90,010	18,345	15,521	1,004	7,624	621	9,881	143,006
Dec	88,767	18,825	15,726	1,005	7,597	626	10,454	143,000
Average	90,580	20,779	13,901	840	7,118	521	9,212	142,951
Percent of Total Obligation	63.4%	14.5%	9.7%	0.6%	5.0%	0.4%	6.4%	100.0%

Table 5-3 PJM capacity market load obligation served by PJM EDCs and affiliates: Calendar year 2006

	PJM EDCs					PJM EDC Generating Affiliates					PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	51,307	471	42,673	92,037	2,414	65,614	(1,547)	(40,034)	23,520	513	0	1,382	10,573	11,694	261
Feb	51,318	489	42,746	92,032	2,521	65,614	(1,789)	(40,128)	23,553	144	0	1,421	10,515	11,653	283
Mar	51,341	(12)	42,736	91,519	2,546	65,581	(2,127)	(39,617)	23,617	220	0	1,430	10,587	11,763	254
Apr	51,340	(104)	42,612	91,367	2,481	65,582	(1,827)	(40,137)	23,029	589	0	1,437	11,358	12,580	215
May	51,340	(66)	42,364	90,688	2,950	66,692	(2,815)	(40,048)	23,075	754	0	1,868	10,955	12,586	237
Jun	51,450	1	40,245	90,230	1,466	66,974	(1,556)	(40,383)	22,162	2,873	0	3,083	10,269	12,877	475
Jul	51,471	(257)	40,956	90,138	2,032	66,979	(1,774)	(43,970)	18,361	2,874	0	3,651	12,115	15,693	73
Aug	51,481	48	40,368	90,104	1,793	66,954	(2,164)	(43,680)	18,375	2,735	0	3,587	12,167	15,673	81
Sep	51,458	(150)	40,568	90,115	1,761	66,788	(1,791)	(43,753)	18,400	2,844	0	3,519	12,250	15,663	106
Oct	51,255	(234)	40,859	90,069	1,811	66,974	(2,702)	(43,146)	18,319	2,807	0	3,640	11,674	15,200	114
Nov	51,255	(338)	40,954	90,010	1,861	66,974	(2,314)	(43,467)	18,345	2,848	0	3,611	12,036	15,521	126
Dec	51,255	(358)	40,298	88,767	2,428	66,619	(2,326)	(43,233)	18,825	2,235	0	3,713	12,260	15,726	247
Average	51,356	(46)	41,441	90,580	2,171	66,451	(2,065)	(41,812)	20,779	1,795	0	2,703	11,403	13,901	205
Percent of Total Obligation	56.7%	(0.1%)	45.8%	102.4%	2.4%	319.8%	(9.9%)	(201.2%)	108.7%	8.7%	0.0%	19.4%	82.0%	101.4%	1.4%

Table 5-4 PJM capacity market load obligation served by non-PJM EDC affiliates: Calendar year 2006

	Non-PJM EDC Generating Affiliates					Non-PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	12,908	(316)	(11,021)	606	965	0	660	6,720	6,374	1,006
Feb	12,908	(285)	(11,076)	606	941	0	626	6,720	6,336	1,010
Mar	12,908	(34)	(11,355)	606	913	0	755	6,780	6,372	1,163
Apr	12,908	(141)	(11,201)	606	960	0	822	6,725	6,369	1,178
May	12,908	(69)	(11,480)	607	752	0	1,107	6,386	6,963	530
Jun	12,862	(535)	(10,892)	1,005	430	0	792	6,403	6,923	272
Jul	12,862	(512)	(10,653)	1,006	691	0	1,031	6,882	7,649	264
Aug	12,862	(487)	(10,659)	1,006	710	0	854	7,129	7,630	353
Sep	12,538	(783)	(10,104)	1,006	645	0	878	6,827	7,548	157
Oct	12,625	(231)	(10,544)	1,003	847	0	971	7,218	7,951	238
Nov	12,625	(228)	(10,490)	1,004	903	0	641	7,253	7,624	270
Dec	12,625	(231)	(10,460)	1,005	929	0	1,165	6,725	7,597	293
Average	12,795	(320)	(10,828)	840	807	0	861	6,815	7,118	558
Percent of Total Obligation	1,523.0%	(38.1%)	(1,288.9%)	196.0%	96.0%	0.0%	12.1%	95.7%	107.8%	7.8%

Table 5-5 PJM capacity market load obligation served by non-EDC affiliates: Calendar year 2006

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	23,671	(727)	(18,666)	144	4,134	0	76	8,581	8,361	296
Feb	23,684	(955)	(18,586)	157	3,986	0	493	8,690	8,419	764
Mar	23,683	(587)	(18,731)	534	3,831	0	575	8,473	8,453	595
Apr	23,634	(701)	(18,882)	534	3,517	0	514	8,406	8,488	432
May	23,617	(806)	(18,568)	534	3,709	0	782	8,614	8,607	789
Jun	23,647	(1,223)	(18,426)	610	3,388	0	(562)	10,456	9,131	763
Jul	23,624	(1,352)	(18,250)	616	3,406	0	(787)	10,365	9,515	63
Aug	23,613	(1,361)	(18,256)	618	3,378	0	(476)	10,510	9,651	383
Sep	23,927	(1,202)	(18,933)	618	3,174	0	(470)	10,628	9,771	387
Oct	23,825	(1,107)	(18,671)	617	3,430	0	(336)	10,556	9,754	466
Nov	23,826	(1,028)	(18,828)	621	3,349	0	(343)	10,649	9,881	425
Dec	24,181	(1,604)	(18,968)	626	2,983	0	(358)	11,138	10,454	326
Average	23,745	(1,055)	(18,646)	521	3,523	0	(77)	9,761	9,212	472
Percent of Total Obligation	4,555.0%	(202.5%)	(3,577.0%)	775.5%	675.5%	0.0%	(0.8%)	106.0%	105.2%	5.2%

Market Concentration

Market concentration is assessed using market shares, concentration ratios and residual supply indices as measures. Concentration ratios are a summary measure of market share, a key element of market structure.[13] The residual supply index (RSI) is a measure of the extent to which one or more generation owners are pivotal suppliers in a market.

High Herfindahl-Hirschman Index (HHI) concentration ratios mean that a comparatively small number of sellers dominates a market, while low concentration ratios mean that a larger number of sellers shares market sales more equally. Concentration measures must be applied carefully in assessing the competitiveness of markets. Low aggregate market concentration ratios do not establish that a market is competitive, that market participants cannot exercise market power or that concentration is not high in particular geographic market areas. High aggregate market concentration ratios do, however, indicate an increased potential for market participants to exercise market power.

The RSI measure recognizes that market shares and concentration ratios do not measure the extent to which an owner's generation facilities are pivotal to meeting demand. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. When a generation owner or owners are pivotal, they have the ability to affect market price, regardless of market share. In effect, they have a monopoly position at the margin. The RSI is a general measure that can be used with any number of pivotal suppliers. An RSI greater than 1.0 for three generation owners is a reasonable benchmark for a competitive market structure but does not guarantee that there is no market power, while an RSI less than 1.0 for three or fewer generation owners clearly indicates a significant ability to exercise market power. If the RSI is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price. If the RSI is less than 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices.[14]

The MMU calculated HHI and RSI metrics for the PJM Capacity Credit Market and for the PJM Capacity Market during calendar year 2006.

Capacity Credit Market

The HHI analysis indicates that, on average, the PJM CCM in 2006 exhibited moderate levels of concentration in the Daily CCM and high levels of concentration in the Monthly and Multimonthly CCM.[15] As shown in Table 5-6, HHIs for the Daily CCM averaged 1576 during this period, with a maximum of 2635 and a minimum of 867 (four firms with equal market shares would result in an HHI of 2500).[16] The highest market share for any entity in one daily auction was 44.9 percent, while the highest average daily market share for

13 See *2006 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," for a more detailed discussion of concentration ratios and the HHI and of the calculation of the residual supply index.

14 For additional information on the three pivotal supplier test and its calculation, see *2006 State of the Market Report*, Volume II, Appendix J, "Three Pivotal Supplier Test."

15 The HHI calculations use capacity cleared in each respective auction. This is consistent with the appropriate definition of the market. In prior state of the market reports, HHI calculations used total capacity offered in each respective auction. In general, the calculated HHIs in 2006 are higher using cleared capacity than offered capacity.

16 PJM CCM results are reported by the time period during which the auction was run and not by the time period to which the auction applies.

any entity across all of the daily auctions was 28.8 percent.[17] Of 365 daily auctions, 82 (22.5 percent) had an HHI greater than 1800. HHIs for the longer-term Monthly and Multimonthly CCM averaged 3611, with a maximum of 10000 and a minimum of 1691 (three firms with equal market shares would result in an HHI of 3333). The highest market share for any entity in one monthly/multimonthly auction was 100.0 percent, while the highest average market share for any entity across all of the monthly/multimonthly auctions was 30.5 percent. All but one of the 65 monthly/multimonthly auctions (98.5 percent) had an HHI greater than 1800.

Table 5-6 PJM CCM HHI: Calendar year 2006

	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	1576	3611
Minimum	867	1691
Maximum	2635	10000
Highest Market Share (One Auction)	44.9%	100.0%
Highest Market Share (All Auctions)	28.8%	30.5%
# Auctions	365	65
# Auctions with HHI >1800	82	64
% Auctions with HHI >1800	22.5%	98.5%

The RSI analysis indicates that there were significant market structure issues in both the Daily CCM and the Monthly and Multimonthly CCM for 2006.[18] Table 5-7 shows RSI values for the daily CCM auctions and the monthly and multimonthly CCM auctions. The RSI results for the Daily CCM indicate that all daily auctions had three or fewer jointly pivotal suppliers. The average three pivotal supplier RSI level for calendar year 2006 was 0.50, while one supplier was individually pivotal in 329 of the 365 daily auctions (90.1 percent). The RSI results for the Monthly and Multimonthly CCM indicate that all of the auctions had three or fewer jointly pivotal suppliers. The average three pivotal supplier RSI was 0.17, while one supplier was individually pivotal in 64 of the 65 monthly auctions (98.5 percent).

17 The market share for an entity across all auctions is calculated as the average market share for the entity for all 365 daily auctions or all 65 monthly and multimonthly auctions. For auctions in which an entity did not participate or clear, the entity was assigned a zero market share in the calculation of the multi-auction market share.

18 The RSI calculations use a market definition that includes those offers with offer prices less than or equal to 150 percent of the capacity market-clearing price for the relevant market. This is consistent with the appropriate definition of competitive offers. In prior state of the market reports, RSI calculations for the capacity market included all offers. In general, use of a threshold for competitive offers reduced calculated 2006 RSI values and increased the number of 2006 auctions with three or fewer pivotal suppliers when compared to calculations that assume all offers are competitive.

Table 5-7 PJM CCM three pivotal supplier residual supply index (RSI): Calendar year 2006 [19]

	Daily Market RSI_3	Monthly and Multimonthly Market RSI_3
Average	0.50	0.17
Minimum	0.26	0.00
Maximum	0.90	0.54
# Auctions	365	65
# Auctions with = 1 Pivotal Supplier	329	64
% Auctions with = 1 Pivotal Supplier	90.1%	98.5%
# Auctions with <= 3 Pivotal Suppliers	365	65
% Auctions with <= 3 Pivotal Suppliers	100.0%	100.0%

Capacity Market

The market structure analyses presented above focus on the operation of the PJM CCM which included only 6.4 percent of total capacity obligations traded in PJM-operated markets in 2006. To provide a more complete assessment of competition in the PJM Capacity Market, the MMU also analyzed total capacity without regard to whether it was sold in the PJM-operated market, through bilateral agreements or self-supplied.

The market structure in the aggregate PJM Capacity Market is shown for the beginning of each interval (January 1, June 1 and October 1) and for December 31 in Table 5-8.

Total capacity ownership was at low concentration levels throughout the year, with HHIs at 925 on January 1 and December 31.[20] The highest market share declined from 16.7 percent to 16.4 percent. There was a single pivotal supplier throughout the year, with four individual suppliers who were each pivotal on a stand-alone basis. In other words, the capacity owned by any of these individually pivotal suppliers was required in order to meet the total demand for capacity (capacity obligation) in PJM.

The market defined by total capacity exhibits significant market structure issues, measured by the pivotal supplier results.[21] As a general matter, the results of the three pivotal supplier test can differ from the results of the HHI and market share tests and total capacity illustrates that situation. As in this case, the three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500, and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500, and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it.

19 RSI_x is the residual supply index, using "x" pivotal suppliers.

20 The aggregate PJM Capacity Market is not a formal market as there is no single clearing price, but includes all capacity in the PJM footprint. The measures of market structure include all capacity as there is no market-clearing price or quantity. These measures of market structure are descriptive of the overall patterns of capacity ownership in the PJM footprint.

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

Table 5-8 PJM capacity: Calendar year 2006

	01-Jan	01-Jun	01-Oct	31-Dec
Unforced Capacity (MW)	152,349	152,581	152,887	152,440
Obligation (MW)	142,772	142,864	142,896	142,992
HHI	925	930	928	925
Highest Market Share	16.7%	16.4%	16.4%	16.4%
RSI_1	0.89	0.89	0.89	0.89
RSI_3	0.58	0.59	0.59	0.58
Pivotal Suppliers	1	1	1	1

External and Internal Capacity Transactions

PJM capacity resources may be traded bilaterally within PJM and between PJM and external markets.

External Capacity Transactions

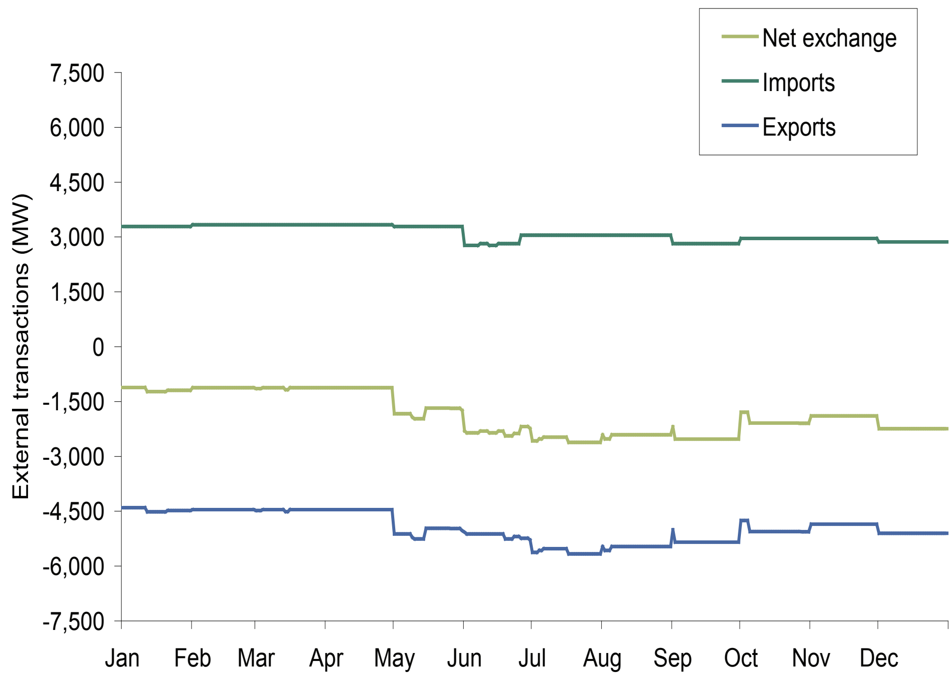
External bilateral transactions include imports of capacity resources from other control areas and exports of capacity resources to control areas outside of PJM.[22] Net exchange is equal to imports less exports.

As shown in Table 5-1 and Figure 5-3, Capacity Market participants' external bilateral purchases (i.e., imports) of capacity resources were relatively flat in 2006, averaging 3,093 MW, which was a decrease of 904 MW or 22.6 percent from the average of 3,997 MW for the 2005 ComEd PCI period.

During 2006, an average of 4,958 MW of capacity resources was exported from the PJM Capacity Market, which was a decrease of 74 MW or 1.5 percent from the average of 5,032 MW for the 2005 ComEd PCI period. The result was an average net exchange of -1,865 MW of capacity resources for 2006, which was a decrease of 830 MW or 80.2 percent from the average net exchange of -1,035 MW for the 2005 ComEd PCI period.

22 The sink (destination) of exports cannot be identified since these data are not required from member companies.

Figure 5-3 External PJM Capacity Market transactions: Calendar year 2006



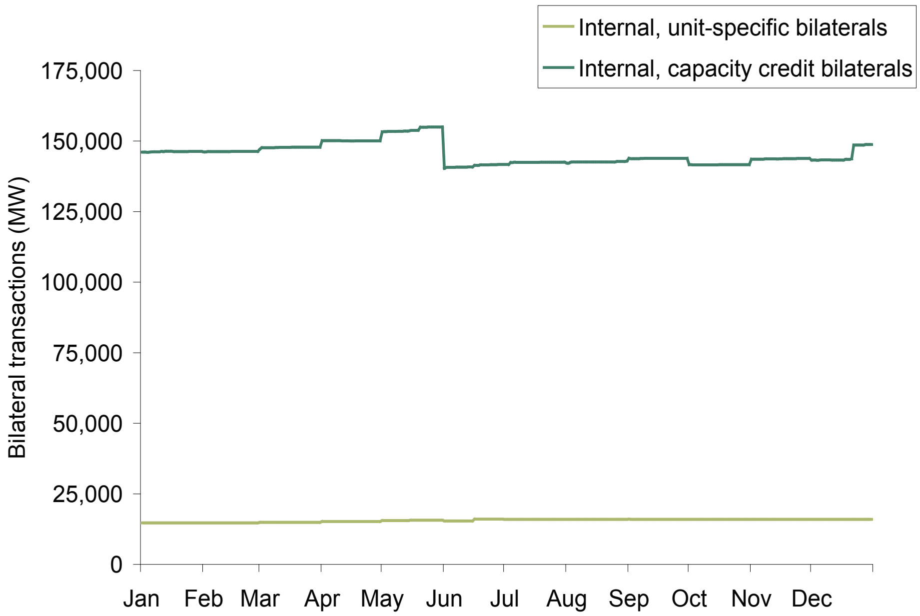
Internal Bilateral Transactions

Internal bilateral transactions are agreements between two parties to buy and sell capacity credits within PJM, but outside of the PJM Capacity Credit Market.[23] Unit-specific transactions are for capacity credits from a specific generating unit while capacity credit transactions are for non unit-specific capacity credits. Both types of transactions may be repeated multiple times among parties, for the same units or credits, with the result that transaction volume can exceed obligation.

During 2006, internal, unit-specific transactions for the PJM Capacity Market averaged 15,548 MW, which was a decrease of 2,806 MW or 15.3 percent from the average of 18,354 MW for the ComEd PCI period. (See Table 5-1 and Figure 5-4.) Internal capacity credit transactions in 2006 averaged 145,404 MW, which was an increase of 7,387 MW or 5.4 percent from the average of 138,017 MW for the 2005 ComEd PCI period. Total internal bilateral transactions in 2006 averaged 160,952 MW, an increase of 4,581 MW or 2.9 percent from the 156,371 MW average for the 2005 ComEd PCI period.

23 As of December 31, 2006, only volumes from internal bilateral transactions were reported to PJM. Pricing data were not required from member companies.

Figure 5-4 Internal bilateral PJM Capacity Market transactions: Calendar year 2006



Active Load Management (ALM) Credits

Active load management (ALM) reflects the ability of individual customers, under contract with their LSE, to reduce specified amounts of load during an emergency. ALM credits, measured in MW of curtailable load, reduce LSE capacity obligations and thus the total PJM capacity obligation.[24]

During 2006, ALM credits in the PJM Capacity Market averaged 1,828 MW, down 214 MW (10.5 percent) from 2,042 MW in the 2005 ComEd PCI period. (See Table 5-1.)

Market Performance

Capacity Credit Market Volumes and Prices

During 2006, PJM operated the Daily, Monthly and Multimonthly CCM. Figure 5-5 and Table 5-12 show prices and volumes for 2006 in PJM's Daily and longer-term CCM. (Also see Table 5-13.) The Daily CCM averaged 3,013 MW of transactions, representing 2.1 percent of the period's 142,951 MW average daily capacity obligation. The average transaction volume for 2006 was 1,408 MW greater than the 2005 ComEd PCI period average of 1,605 MW, which had been 1.1 percent of the 142,783 MW average capacity obligations for the period. The Monthly and Multimonthly CCM averaged 6,105 MW of transactions, which was 4.3 percent of the average daily capacity obligations for 2006 and 705 MW higher than the 2005 ComEd PCI period average of 5,400 MW, which was 3.8 percent of the average capacity obligations for the

24 ALM capacity credits reduce capacity obligations throughout the year. The fixed ALM value for non-summer months (October through May) is calculated by PJM based upon daily values of nominated ALM in the PJM eCapacity system for the summer months.

period. Thus, on average, the CCM accounted for 6.4 percent of all average daily capacity obligations in 2006.

The volume-weighted, average price for 2006 was $1.92 per MW-day in the Daily CCM and $7.60 per MW-day in the Monthly and Multimonthly CCM. The volume-weighted, average price for the entire CCM was $5.73 per MW-day.[25] Prices in the Daily CCM during 2006 were $1.69 higher than the 2005 ComEd PCI period price of $0.23. Prices in the Monthly and Multimonthly CCM were $0.83 higher than the 2005 ComEd PCI period price of $6.77.

As shown in Table 5-9, in the January 1, 2006, Daily CCM prices increased to $79.00 per MW-day from $0.02 per MW-day on December 31, 2005, primarily because of a shift in lower-priced capacity from the daily market to the bilateral market and to a shift in demand from the monthly to the daily market. Although capacity offered into the market increased by 452 MW from December 31 to January 1 and the percentage of available capacity offered into the market increased from 47.3 percent to 50.5 percent, lower-priced offers from capacity sellers were replaced by higher-priced offers from other sellers. In addition, demand also increased by 957 MW from the previous day because of decreased bilateral purchases and decreased purchases in the Monthly and Multimonthly CCM. Prices remained at this level through January 3 because the auctions for the first three days of January had all been run on Friday, December 30, 2005. Daily auctions for Saturday, Sunday and Monday are always run on the preceding Friday, and Tuesday was also run on this day because Monday, January 2, was a PJM holiday. Prices decreased to $50.00 per MW-day on January 4 as capacity owners responded to the higher prices by offering more capacity into the market and reducing their offer prices. Prices eventually fell to $1.00 per MW-day on January 12 and remained near this level throughout the rest of the month.

As shown in Table 5-10, in the July 1, 2006, Daily CCM prices increased to $13.19 per MW-day from $0.10 per MW-day on June 30, 2006, primarily because of a decrease in the amount of low-priced capacity offered and an increase in demand. Capacity offered into the market decreased by 1,009 MW from June 30 to July 1 as several lower-price suppliers shifted to either bilateral sales or higher-priced offers in the Monthly and Multimonthly CCM. In addition, the available capacity not offered into the daily market increased by 877 MW. Demand increased by 201 MW from the previous day because of decreased bilateral purchases. Prices remained at this level through July 5 in part because the auctions for the first three days of July had all been run on Friday, June 30. Daily auctions for Saturday, Sunday and Monday are always run on the preceding Friday. Tuesday was July 4, a PJM holiday, so auctions for July 4 and July 5 were run on Monday, July 3.

On July 7 capacity owners responded to the higher prices by offering more capacity into the market, causing the decrease in prices to $2.50 per MW-day. Offered volumes increased by 417 MW from July 1 to July 7, as some suppliers offered into the daily market part of their net excess that had not been previously offered. Prices rose to $5.00 per MW-day on July 10 and remained near this level for the rest of the month as supply and demand remained relatively stable.

25 Graph and average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.

As shown in Table 5-11 and Table 5-12, Monthly and Multimonthly CCM prices increased in June. The June monthly market price increased as a result of higher offer prices. June multimonthly prices increased because of an increase in demand that resulted from shifts from bilateral contracts to the multimonthly market. Multimonthly CCM prices declined over the remainder of the year as supply and demand came more into balance but still remained higher than January through May.

Table 5-9 Daily available capacity vs. offered capacity: December 31, 2005, to January 12, 2006

	Available Capacity (MW)	Capacity Offered (MW)	Capacity Not Offered (MW)	Percent Offered	Percent Not Offered	Clearing Price ($/MW-day)	Capacity Bid (MW)	Capacity Cleared (MW)
31-Dec-05	12,874	6,084	6,790	47.3%	52.7%	$0.02	2,434	2,434
1-Jan-06	12,967	6,536	6,431	50.5%	49.5%	$79.00	3,391	3,362
2-Jan-06	13,050	6,588	6,462	50.6%	49.4%	$79.00	3,383	3,354
3-Jan-06	13,052	6,594	6,458	50.6%	49.4%	$79.00	3,387	3,358
4-Jan-06	12,982	9,555	3,427	73.6%	26.4%	$50.00	3,359	3,359
5-Jan-06	12,953	9,078	3,875	70.1%	29.9%	$30.00	3,305	3,305
6-Jan-06	12,896	9,466	3,430	73.4%	26.6%	$5.00	3,247	3,247
7-Jan-06	12,966	10,137	2,829	78.2%	21.8%	$3.50	3,300	3,300
8-Jan-06	12,966	10,006	2,960	77.2%	22.8%	$5.00	3,300	3,300
9-Jan-06	12,921	10,009	2,912	77.5%	22.5%	$5.00	3,291	3,291
10-Jan-06	13,013	9,485	3,528	72.9%	27.1%	$2.00	3,295	3,295
11-Jan-06	12,901	9,635	3,266	74.7%	25.3%	$1.05	3,194	3,194
12-Jan-06	12,785	9,440	3,345	73.8%	26.2%	$1.00	3,191	3,191

Table 5-10 Daily available capacity vs. offered capacity: June 30, 2006, to July 12, 2006

	Available Capacity (MW)	Capacity Offered (MW)	Capacity Not Offered (MW)	Percent Offered	Percent Not Offered	Clearing Price ($/MW-day)	Capacity Bid (MW)	Capacity Cleared (MW)
30-Jun-06	13,167	10,705	2,462	81.3%	18.7%	$0.10	3,414	3,414
1-Jul-06	13,035	9,696	3,339	74.4%	25.6%	$13.19	3,615	3,615
2-Jul-06	13,035	9,696	3,339	74.4%	25.6%	$13.19	3,615	3,615
3-Jul-06	13,059	9,693	3,366	74.2%	25.8%	$13.19	3,636	3,636
4-Jul-06	12,737	8,935	3,802	70.2%	29.8%	$13.19	3,258	3,258
5-Jul-06	12,741	9,403	3,338	73.8%	26.2%	$13.19	3,265	3,265
6-Jul-06	12,699	9,788	2,911	77.1%	22.9%	$10.00	3,174	3,174
7-Jul-06	12,791	10,113	2,678	79.1%	20.9%	$2.50	3,258	3,258
8-Jul-06	12,786	9,612	3,174	75.2%	24.8%	$1.24	3,245	3,245
9-Jul-06	12,786	9,612	3,174	75.2%	24.8%	$1.24	3,245	3,245
10-Jul-06	12,801	9,616	3,185	75.1%	24.9%	$5.00	3,265	3,265
11-Jul-06	12,781	10,059	2,722	78.7%	21.3%	$5.00	3,279	3,279
12-Jul-06	12,777	10,052	2,725	78.7%	21.3%	$5.00	3,287	3,287

Table 5-11 Monthly and multimonthly capacity volumes and prices: May to July 2006

	Daily Average (MW)						Weighted-Average Price ($ per MW-day)		
	Monthly Market Purchases	MultiMonthly Market Purchases	Monthly Market Offered	Monthly Market Bid	MultiMonthly Market Offered	MultiMonthly Market Bid	Monthly Clearing Price	MultiMonthly Clearing Price	Combined Clearing Price
May	1,636	3,540	1,357	1,038	1,258	1,315	$1.11	$4.61	$3.50
Jun	1,695	5,509	1,440	1,524	1,778	2,754	$22.08	$12.27	$14.58
Jul	1,678	5,641	2,146	1,098	898	1,429	$1.81	$12.06	$9.71

Figure 5-5 PJM Daily and Monthly/Multimonthly CCM performance: Calendar year 2006

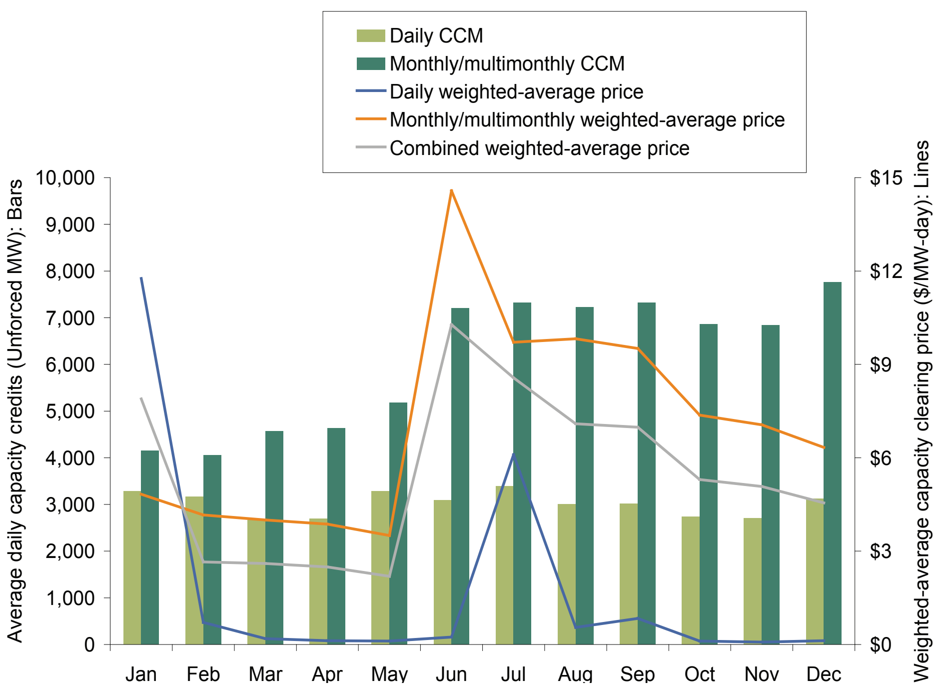


Table 5-12 PJM Capacity Credit Market: Calendar year 2006

	Average Daily Capacity Credits (MW)			Weighted-Average Price ($ per MW-day)		
	Daily CCM	Monthly and Multimonthly CCM	Combined Markets	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
Jan	3,286	4,153	7,439	$11.76	$4.83	$7.89
Feb	3,163	4,058	7,221	$0.71	$4.16	$2.65
Mar	2,662	4,567	7,229	$0.19	$4.00	$2.60
Apr	2,698	4,630	7,328	$0.12	$3.87	$2.49
May	3,278	5,176	8,454	$0.11	$3.50	$2.19
Jun	3,090	7,204	10,294	$0.24	$14.58	$10.28
Jul	3,391	7,319	10,710	$6.10	$9.71	$8.57
Aug	3,007	7,223	10,230	$0.55	$9.82	$7.09
Sep	3,019	7,322	10,341	$0.84	$9.51	$6.98
Oct	2,732	6,859	9,591	$0.11	$7.37	$5.30
Nov	2,702	6,842	9,544	$0.08	$7.06	$5.08
Dec	3,121	7,758	10,879	$0.12	$6.33	$4.55
2006	3,013	6,105	9,118	$1.92	$7.60	$5.73

Calendar Years 1999 through 2006

Figure 5-6 and Table 5-13 show prices and volumes in PJM's Daily and longer-term CCM from June 1999 through December 2006.[26] Since the interval system was introduced in July 2001, overall volume in the CCM has increased; prices have declined and remained relatively stable with the exception of the summer of 2004 and capacity obligations have almost tripled. The share of load obligation traded in both the Daily CCM and in the Monthly and Multimonthly CCM has increased. Daily CCM volume increased from 1.5 percent of average obligation in 2001 to 2.1 percent in 2006. Monthly and multimonthly CCM volume increased from 2.2 percent of obligation in 2001 to 4.3 percent of average obligation in 2006.

26 After June 1, 1999, the PJM Capacity Credit Market was based on unforced capacity. Before this date, the market had been based on installed capacity.

Figure 5-6 PJM Daily and Monthly/Multimonthly CCM performance: June 1999 to December 2006

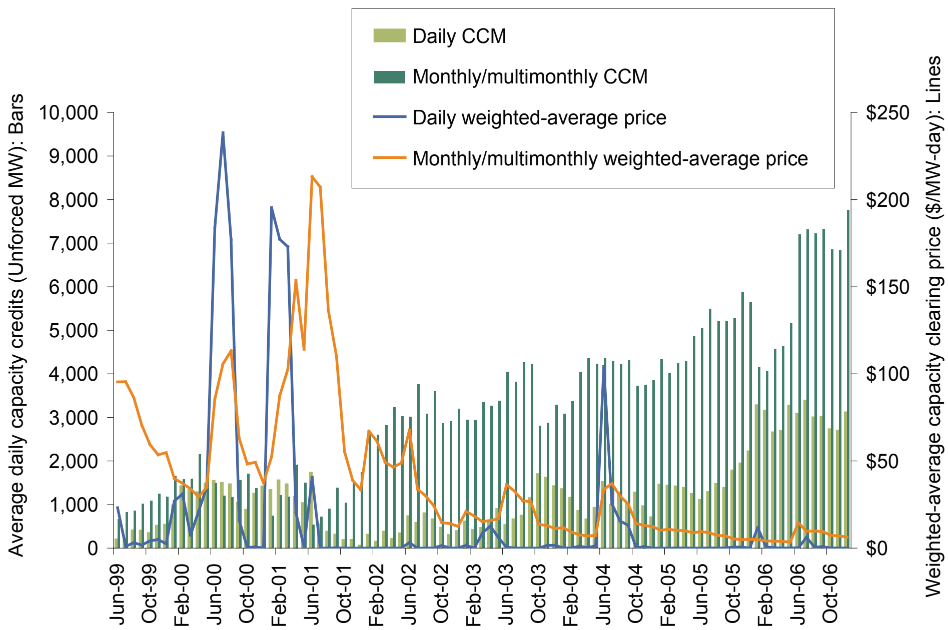


Table 5-13 PJM Capacity Credit Market: Calendar years 1999 to 2006

	Average Daily Capacity Credits						Weighted-Average Price ($ per MW-day)		
	Daily CCM (MW)	Percent of Obligation	Monthly and Multimonthly CCM (MW)	Percent of Obligation	Combined Markets (MW)	Percent of Obligation	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
1999	374	0.7%	981	1.9%	1,355	2.6%	$4.69	$70.36	$52.24
2000	1,304	2.5%	1,561	3.0%	2,865	5.4%	$69.39	$53.16	$60.55
2001	829	1.5%	1,197	2.2%	2,026	3.7%	$87.98	$100.43	$95.34
2002	450	0.8%	3,066	5.3%	3,516	6.1%	$0.59	$38.21	$33.40
2003	907	1.4%	3,436	5.2%	4,343	6.6%	$2.14	$21.57	$17.51
2004	1,062	1.4%	3,966	5.1%	5,028	6.5%	$17.21	$17.88	$17.74
2005	1,516	1.2%	4,968	3.9%	6,484	5.1%	$0.15	$7.94	$6.12
2006	3,013	2.1%	6,105	4.3%	9,118	6.4%	$1.92	$7.60	$5.73

Generator Performance

Generator performance is a function of incentives from energy and capacity markets as well as the physical nature of the units and the level of expenditures made to maintain the capability of the units. Generator performance can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates). In prior state of the market reports, the generator performance analysis was based solely on the capacity resources in the PJM Mid-Atlantic Region and the AP Control Zone. The generator performance analysis for the *2006 State of the Market Report* includes all PJM capacity resources for which there are data in the PJM GADS database.

Generator Performance Factors

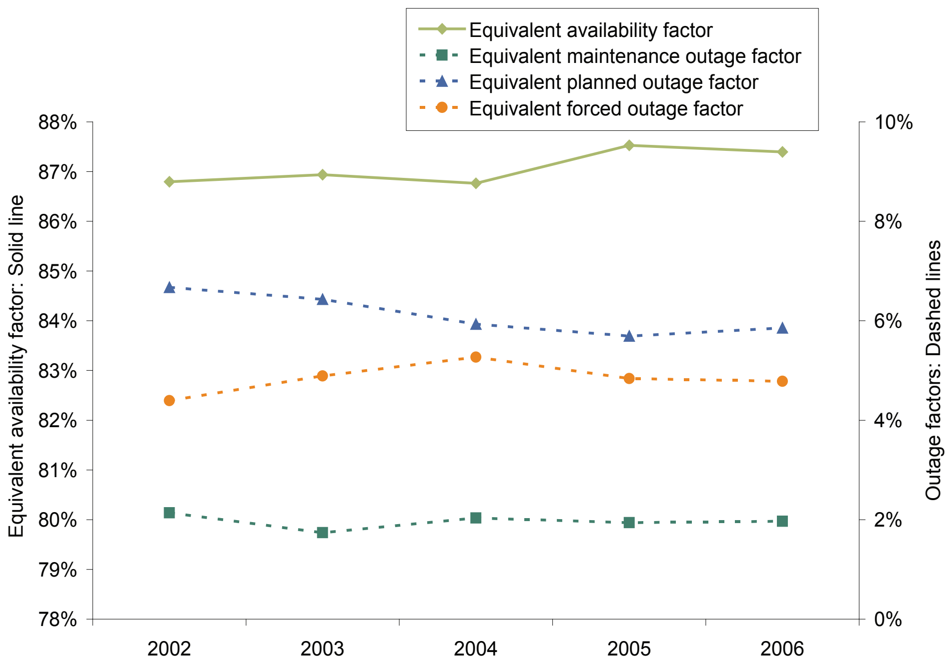
Generator performance factors are based on a defined period, usually a year, and are directly comparable.[27] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF decreased from 87.6 percent in 2005 to 87.4 percent in 2006. The EFOF decreased by 0.1 percentage points from 2005 to 2006 while the EPOF increased by about 0.2 percentage points and the EMOF did not change. [28] (See Figure 5-7.)

27 Data from all PJM capacity resources for the years 2002 through 2006 were analyzed. In the *2005 State of the Market Report*, data from only the PJM Mid-Atlantic Region and the AP Control Zone for the years 1994 through 2005 were analyzed.

28 The performance factor data include all units from the PJM Control Area. Data for the year 2006 may be incomplete as of the download date as corrections can be made at anytime with permission from the PJM GADS administrators. Data are for 12 months ended December 31, 2006, as downloaded from the PJM GADS database on January 23, 2007.

Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2002 to 2006



Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. Unforced capacity for any individual generating unit is equal to one minus the EFORd multiplied by the unit's net dependable summer capability. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

EFORd[29] calculations use historical data, including equivalent forced outage hours,[30] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[31] Between 2002 and 2004, the average PJM EFORd increased from 5.4 percent in 2002 to 6.7 percent in 2003 and 7.3 percent in 2004 before it decreased to 6.6 percent in 2005 and 6.4 percent in 2006.[32] Figure 5-8 shows the average EFORd since 2002 for all units in the PJM Control Area.

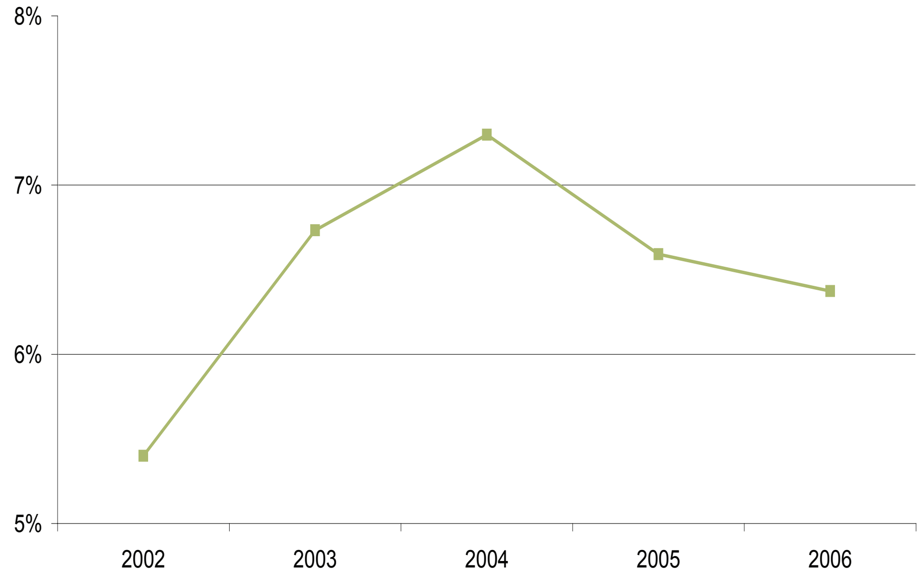
29 EFORd was calculated using all units that have participated in the PJM Capacity Market. Data for these units are contained in the PJM eGADS database. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd.

30 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

31 See PJM "Manual 22: Generator Resource Performance Indices," Revision 14 (June 1, 2005), Equation 8.

32 Data are for the 12 months ended December 31, 2006, as downloaded from the PJM GADS database on January 23, 2007. Data for the year 2006 may be incomplete as of the download date as corrections can be made at anytime with permission from the PJM GADS administrators.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2002 to 2006 [33]



Components of Change in EFORd

Table 5-14 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[34] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

33 Data for 2002 and 2003 are incomplete for some units in newly integrated areas. Available information supports the conclusion that there is no significant impact on the results of the analysis.

34 The generating unit types are: steam, nuclear, diesel, combustion turbine, combined-cycle and hydroelectric. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

Table 5-14 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2002 to 2006

	2002	2003	2004	2005	2006	Change in 2006 from 2005
Combined Cycle	0.2	0.4	0.6	0.7	0.5	(0.2)
Combustion Turbine	0.5	1.1	1.3	1.5	1.4	(0.1)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.2	0.1	0.1	0.0
Nuclear	0.4	0.6	0.6	0.3	0.3	0.0
Steam	4.2	4.5	4.6	4.0	4.1	0.1
Total	5.4	6.7	7.3	6.6	6.4	(0.2)

The decrease in overall PJM Control Area EFORd of 0.2 percentage points (a 3.0 percent decline) between 2005 and 2006 resulted primarily from better performance of combustion turbine units (501 generating units), combined-cycle units (103 generating units) and nuclear units (32 generating units) which together accounted for 0.3 of the 0.2 percentage point overall decrease.[35] This decrease was partially offset by the decline in the performance of fossil steam units (316 generating units) Fossil steam units accounted for an increase of 0.1 percentage points in the overall total.

Of the 1,231 generating units in the EFORd analysis, during calendar year 2006, 498 units had decreased EFORds, 443 units had increased EFORds and the remaining 290 units had unchanged EFORds. Had the 498 units with lower forced outage rates not experienced rates lower than the average, the 2006 EFORd would have been 8.3 percent.

Changes in outage rates by unit type and changes in capacity by unit type combined to produce the observed impacts on the system EFORd. Since total capability from both combustion turbine and combined-cycle units remained nearly the same from year to year, the decreased forced outage rates for these unit types was the reason for their contribution to the decreased system EFORd.

Table 5-15 shows the relative contributions of EFORd and capacity to EFORd levels by unit type and for the system. Approximately 24 percent of the contribution of combustion turbine units to the decreased system EFORd was the result of reduced combustion turbine capacity while 76 percent of the contribution of combustion turbine units to the decreased system EFORd was the result of lower EFORd levels for combustion turbines. Approximately minus 9 percent of the contribution of combined-cycle units to the decreased system EFORd was the result of increased combined-cycle capacity while 109 percent of the contribution of combined-cycle units to the decreased system EFORd was the result of lower EFORd levels for combined-cycle units. Overall, 75 percent of the decrease in EFORd from 2005 to 2006 was the result of decreased EFORd for specific unit types while the balance was the result of the change in the mix of capacity by unit type.

35 A single unit may include more than one set of generator terminals aggregated as a single generator.

Table 5-15 Percent change in contribution to EFORd (Unit type): 2006 compared to 2005

	Contribution Change Due to Capacity	Contribution Change Due to EFORd
Combined Cycle	(9.0%)	109.0%
Combustion Turbine	23.8%	76.2%
Diesel	138.0%	(38.0%)
Hydroelectric	15.2%	84.8%
Nuclear	0.0%	100.0%
Steam	(98.0%)	198.0%
All Unit Types	24.6%	75.4%

Table 5-16 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2002 to 2006

	2002	2003	2004	2005	2006	NERC 2001 to 2005
Combined Cycle	4.7%	5.4%	5.5%	5.4%	4.1%	NA
Combustion Turbine	4.0%	8.2%	8.6%	9.7%	9.1%	9.4%/10.3%
Diesel	6.0%	7.0%	7.9%	13.8%	13.5%	13.5%
Hydroelectric	1.1%	2.2%	3.9%	2.6%	1.9%	3.9%
Nuclear	2.0%	3.2%	3.2%	1.6%	1.4%	4.2%
Steam	7.4%	8.2%	9.1%	8.0%	8.2%	6.4%
Overall	5.4%	6.7%	7.3%	6.6%	6.4%	NA

Table 5-16 compares PJM EFORd data by unit type to North American Electric Reliability Council (NERC) data for corresponding unit types.[36] NERC has not published average EFORd for combined-cycle units because the new calculations for combined-cycle blocks are not ready and have not been tested.[37] The 2006 PJM forced outage rates for combustion turbines, for hydroelectric units and for nuclear units were below the NERC five-year average. The 2006 PJM EFORd for diesel units was at the NERC average. The 2006 PJM EFORd for fossil steam units exceeded the NERC average.[38]

Duty Cycle and EFORd

In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[39] Figure 5-9 shows the increased contribution of peaking units to system average EFORd

36 The PJM data include all combustion turbines as a single unit type.

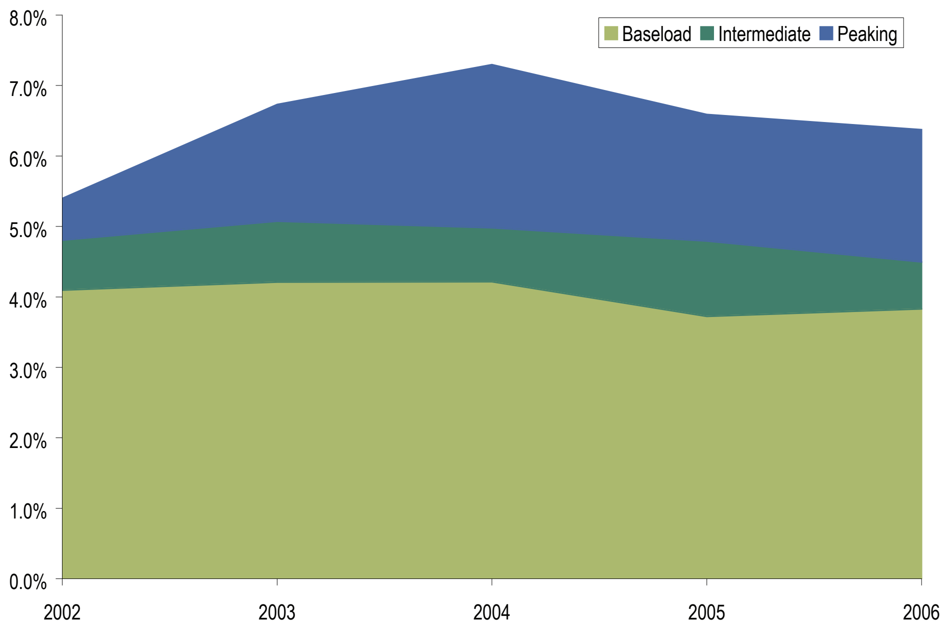
37 Combined-cycle blocks consist of one or more combustion turbines and one or more heat recovery steam generators. The configuration may vary for each individual combined-cycle unit.

38 NERC defines combustion turbines in two categories: jet engines and gas turbines. Their EFORd for the 2001 to 2005 period are 9.4 percent and 10.3 percent, respectively, per NERC's GADS "2001-2005 Generating Unit Statistical Brochure - Units Reporting Events" <ftp://www.nerc.com/pub/sys/all_updl/gads/gar/2001-2005%20Generating-Unit-Statiistical-Brochure-units%20reporting%20events.zip > (28 KB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM Control Area values are weighted by capability for each calendar year.

39 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined to be a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined to be a unit that generates from 10 percent to 50 percent of its available hours. A peaking unit is defined to be a unit that generates less than 10 percent of its available hours. These terms were defined for the purposes of this analysis.

beginning in 2002 through 2004 that, while it decreased slightly in 2005, has remained higher than in 2002. In 2006, of 22,600 MW of combined-cycle units, approximately 20,700 MW are in the intermediate (18,100 MW) and peaking (2,600 MW) classes. Of 27,200 MW of combustion turbine units approximately 26,700 MW are in the intermediate (1,900 MW) and peaking (24,800 MW) classes.

Figure 5-9 Contribution to EFORd by duty cycle: Calendar years 2002 to 2006



Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[40] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

The PJM EAF for 2006 was 87.4 percent; the corresponding EMOF and EPOF were 2.0 percent and 5.8 percent, respectively. As a result, the 2006 PJM EFOF was 4.8 percent. This means 4.8 percent lost availability because of forced outages.

40 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

The major reasons for this lost equivalent availability can be found in Table 5-17.

Table 5-17 Outage cause contribution to PJM EFOF: Calendar year 2006

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	1.12	23.4%
Performance	0.38	8.0%
Boiler Fuel Supply	0.26	5.4%
Electrical	0.23	4.9%
Miscellaneous (Jet Engine)	0.20	4.1%
Boiler Air and Gas Systems	0.18	3.8%
Feedwater System	0.16	3.4%
Auxiliary Systems	0.12	2.5%
Stack Emission	0.11	2.4%
High Pressure Turbine	0.10	2.1%
Controls	0.10	2.1%
Miscellaneous (Generator)	0.09	1.9%
Boiler Piping System	0.09	1.8%
Generator	0.09	1.8%
Boiler Overhaul and Inspections	0.08	1.7%
Valves	0.08	1.6%
Condensing System	0.08	1.6%
Fuel Quality	0.07	1.5%
Reactor Coolant System	0.07	1.5%
All Other Causes	1.17	24.5%
PJM EFOF 2006	4.78	100.0%

Table 5-17 shows that boiler tube leaks, at 23.4 percent of the systemwide EFOF, were the largest contributor to EFOF. Forced outages because of boiler tube leaks reduced system equivalent availability by 1.12 percentage points. Performance caused the second largest reduction to equivalent availability by 0.38 percentage points. Almost all of this reduction was attributable to failing, in whole or in part, PJM seasonal capacity verification tests which require an outage until the problem is solved or the generator takes a capacity derating.

Table 5-18 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2006

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	0.0%	0.0%	0.0%	0.0%	0.0%	33.0%	23.4%
Performance	40.7%	14.6%	15.3%	11.0%	4.4%	3.0%	8.0%
Boiler Fuel Supply	8.3%	0.0%	0.0%	0.0%	0.0%	6.7%	5.4%
Electrical	1.3%	7.1%	0.4%	2.4%	0.1%	5.3%	4.9%
Miscellaneous (Jet Engine)	0.0%	30.0%	0.0%	0.0%	0.0%	0.0%	4.1%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	5.3%	3.8%
Feedwater System	1.3%	0.0%	0.0%	0.0%	0.8%	4.6%	3.4%
Auxiliary Systems	4.9%	11.0%	0.0%	0.1%	2.0%	0.6%	2.5%
Stack Emission	0.0%	0.6%	0.0%	0.0%	0.0%	3.3%	2.4%
High Pressure Turbine	1.7%	0.0%	0.0%	0.0%	0.0%	2.8%	2.1%
Controls	1.2%	1.5%	0.0%	2.8%	13.6%	1.6%	2.1%
Miscellaneous (Generator)	3.8%	0.6%	16.2%	37.7%	2.3%	1.1%	1.9%
Boiler Piping System	1.5%	0.0%	0.0%	0.0%	0.0%	2.3%	1.8%
Generator	0.0%	2.1%	1.3%	2.8%	0.1%	2.0%	1.8%
Boiler Overhaul and Inspections	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%	1.7%
Valves	0.3%	0.0%	0.0%	0.0%	2.4%	2.1%	1.6%
Condensing System	0.6%	0.0%	0.0%	0.0%	6.9%	1.7%	1.6%
Fuel Quality	0.6%	0.1%	0.3%	0.0%	0.0%	2.0%	1.5%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	29.7%	0.0%	1.5%

Table 5-18 shows the major causes of EFOF by unit type. Boiler tube leaks caused 33.0 percent of the EFOF for fossil steam units. Reactor cooling system problems were the cause of 29.7 percent of the lost availability because of forced outages of nuclear units.

Table 5-19 Contribution to EFOF by unit type: Calendar year 2006

	EFOF	Contribution to EFOF
Combined Cycle	3.1%	8.3%
Combustion Turbine	4.3%	13.8%
Diesel	10.5%	0.5%
Hydroelectric	1.3%	1.4%
Nuclear	1.3%	5.0%
Steam	6.8%	71.0%
PJM Systemwide	4.8%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units have the largest share (about 48 percent) of the capacity mix,[41] have a high duty cycle and in 2006 had an EFORd of 8.2 percent which yields a 71.0 percent contribution to EFOF. Nuclear units also have a high duty cycle; their share of the PJM systemwide capacity mix is about 18 percent and in 2006 they had a 1.4 percent EFORd which yields a 5.0 percent contribution to PJM systemwide EFOF. By using the values in Table 5-19 and Table 5-18 one can determine how much the individual unit types' causes contributed to PJM systemwide EFOF. For instance the value for boiler tube leaks in Table 5-18 multiplied by the contribution value in Table 5-19 for the same unit type will yield the percent contribution to the PJM systemwide EFOF for that outage cause.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages that should be deemed outside management control (OMC) in response to the system disturbance of August 14, 2003.[42] NERC specifies, in its January 2006 update to the "Generator Availability Data System Data Reporting Instructions,"[43] in Appendix K,[44] that each OMC outage must be carefully considered as to its cause and nature. An outage can be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[45] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages will be excluded from the calculations used to determine the level of unforced capacity for specific units and thus the amount of unforced capacity for sale in capacity markets. This modified EFORd is termed the XEFORd. All submitted OMC outages will be reviewed by PJM's Capacity Adequacy Department. Table 5-20 shows the impact of OMC outages on EFORd for 2006. The difference is especially noticeable for peaking units (combustion turbines and diesels). This 0.38 percentage point decrease in EFORd translates to a 600 MW increase in unforced capacity.

41 See Table 3-26, "PJM capacity (By fuel source)," *2006 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," at "Existing and Planned Generation."

42 NERC had always provided cause codes for outages that were caused by external forces. However, as a result of the system disturbance on August 14, 2003, NERC specifically created outage specifications for outages that were "outside management control."

43 The "Generator Availability Data System Data Reporting Instructions" can be found on the NERC Web site: <ftp://www.nerc.com/pub/sys/all_updl/gads/dri/2007GADS_DRI.pdf> (4.9 MB).

44 The "Generator Availability Data System Data Reporting Instructions," Appendix K can be found on the NERC Web site: <ftp://www.nerc.com/pub/sys/all_updl/gads/dri/Appendix-K-Outside-Plant-Management-Control.pdf> (161 KB).

45 For a list of these cause codes, see *2006 State of the Market Report*, Volume II, Appendix E, "Capacity Market."

Table 5-20 PJM EFORd vs. XEFORd: Calendar year 2006

	2006 EFORd	2006 XEFORd	Difference
Combined Cycle	4.12%	3.93%	(0.19%)
Combustion Turbine	9.09%	7.42%	(1.67%)
Diesel	13.49%	11.72%	(1.77%)
Hydroelectric	1.94%	1.77%	(0.17%)
Nuclear	1.43%	1.32%	(0.11%)
Steam	8.25%	8.10%	(0.15%)
Overall	6.37%	5.99%	(0.38%)

SECTION 6 – ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation services; 3) regulation and frequency response services; 4) energy imbalance service; 5) operating reserve -- synchronized reserve services; and 6) operating reserve -- supplemental reserve services.[1] Of these, PJM currently provides regulation, energy imbalance and synchronized reserve services through market-based mechanisms.[2] PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis.

Regulation matches generation with very short-term changes in load by moving the output of selected generators up and down via an automatic control signal.[3] Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by demand-side response (DSR). The term, "synchronized reserve market" refers only to the supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but it cannot be selected for both. The Regulation and Synchronized Reserve Markets are cleared simultaneously and cooptimized with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, inter-area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling.[4] Generation owners are paid according to the FERC-approved reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

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.[5]

1 75 FERC ¶ 61,080 (1996).

2 The term "spinning reserve" has been replaced with "synchronized reserve," consistent with modifications made to PJM manuals. This change reflects the fact that demand-side resources may now provide synchronized reserve and such resources are not literally spinning reserve in every case, as are generators.

3 Regulation is used to help control the area control error (ACE). See *2006 State of the Market Report*, Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE.

4 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 76.

5 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."

On August 1, 2005, PJM integrated what had been five regulation control zones into one combined Regulation Market for a trial period. After the trial period and after a report by the PJM Market Monitoring Unit (MMU), PJM stakeholders will vote on whether to keep the combined market. The MMU provided that report on October 18, 2006, and it is under review by PJM members.[6]

PJM operates four Synchronized Reserve Markets: one for the Mid-Atlantic Region, one for the Western Region, one for the Southern Region (Dominion) and one for the ComEd Control Zone.

Overview

Regulation Market

Market Structure

- **Supply.** The supply of offered and eligible regulation in PJM was generally both stable and adequate. Potential regulation supply was enhanced during 2006 by allowing demand-side resources to offer regulation and to satisfy up to 25 percent of the regulation requirement, although no demand-side resources offered regulation during 2006. The ratio of eligible regulation offered to regulation required averaged 2.60 throughout 2006.

- **Demand**. The regulation requirement is set daily for the entire day by PJM to be 1.0 percent of the forecast-peak load for PJM. This requirement was established in August 2006.

- **Market Concentration.** During 2006, the PJM Regulation Market had an average Herfindahl-Hirschman Index (HHI) of 1256 which is classified as "moderately concentrated."[7] The largest hourly market share was 40 percent, and 43 percent of all hours had a maximum market share greater than 20 percent. There were no suppliers with annual average market shares greater than, or equal to, 20 percent. Approximately 26 percent of hours had three pivotal suppliers. The MMU concludes from these results that the PJM Combined Regulation Market in 2006 was characterized by structural market power in 26 percent of the hours.

Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost (LOC), comprises the total offer to the Regulation Market. The regulation offer price is subject to a $100 per MWh offer cap, with the exception of the dominant suppliers, whose offers are capped at marginal cost plus $7.50 per MWh plus lost opportunity cost. All suppliers are paid the market-clearing price. Based on MMU estimates of the marginal cost of regulation, 33 percent of offers exceeded competitive levels in 2006.

6 See Market Monitoring Unit, "Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006" (October 18, 2006) <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20061018-mmu-regulation-market-report.pdf> (76.1 KB).

7 See *2006 State of the Market Report*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Market Performance

- **Price.** For the PJM Regulation Market during 2006 the average price per MWh (regulation market-clearing price including lost opportunity cost) associated with meeting PJM's demand for regulation was $32.69. This represents a decrease of $19.17 from the average price for regulation during 2005. In 2006, based on MMU estimates of the marginal cost of regulation, offers at levels greater than competitive levels set the clearing price for regulation in about 30 percent of all hours.

Synchronized Reserve Market

The structure of each Synchronized Reserve Market (the term, "synchronized reserve market" refers only to Tier 2 synchronized reserve) has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated as markets with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Prices for synchronized reserve in the PJM Mid-Atlantic Region, the ComEd Control Zone, the Western Region and Southern Region are market-clearing prices determined by the supply curve and the administratively defined demand. The cost-based synchronized reserve offers are defined to be the unit-specific incremental cost of providing synchronized reserve plus a margin of $7.50 per MWh plus lost opportunity cost calculated by PJM.

Market Structure

- **Supply.** For the PJM Mid-Atlantic Synchronized Reserve Region, the offered and eligible excess supply ratio was 1.64. For the ComEd Synchronized Reserve Control Zone, the ratio was 1.46.[8] These excess supply ratios are determined using the administratively required synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower because there is usually a significant amount of Tier 1 synchronized reserve available. In August 2006 DSR resources began participating in PJM Synchronized Reserve Markets. As of the end of 2006, the MW contribution of DSR resources to the supply of synchronized reserve remained small, but increasing. Market rules limit the contribution of DSR resources to 25 percent of the administratively required synchronized reserve.

- **Demand.** The average synchronized reserve requirement was: 1,109 MW for the Mid-Atlantic Synchronized Reserve Region; 222 MW for the ComEd Synchronized Reserve Control Zone; 423 MW for the Western Synchronized Reserve Region; and 9 MW for the Southern Synchronized Reserve Region. These requirements are a function of administratively determined, regional requirements. Market demand is less than the requirement by the amount of Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. The average demand for synchronized reserve was: 293 MW for the Mid-Atlantic Synchronized Reserve Region; 59 MW for the ComEd Synchronized Reserve Control Zone; 0 MW for the Southern Synchronized Reserve Region; and 3 MW for the Western Synchronized Reserve Region.

8 The Synchronized Reserve Markets in the Western Region and Southern Region cleared in so few hours that related data for those markets are not meaningful.

- **Market Concentration**. In 2006, market concentration was high in the Tier 2 Synchronized Reserve Markets. The average cleared synchronized reserve market HHI for the Mid-Atlantic Synchronized Reserve Region throughout 2006 was 5686. The average HHI for the ComEd Synchronized Reserve Control Zone was 8305. The average HHI for the Western Synchronized Reserve Region was 7944. The HHI for the Southern Synchronized Reserve Region was always 10000.

Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost calculated by PJM, comprises the total offer price to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MWh, plus lost opportunity cost. All suppliers are paid the higher of the market-clearing price or their offer plus their unit-specific opportunity cost.

Market Performance

- **Price.** The load-weighted, average PJM price for Tier 2 synchronized reserve was $14.94 per MW in 2006, a $0.53 per MW increase from 2005. The load-weighted, average price in 2006 for Tier 2 synchronized reserve was $14.57 per MW in the Mid-Atlantic Synchronized Reserve Region, $16.69 in the ComEd Synchronized Reserve Control Zone, $9.14 in the Western Synchronized Reserve Region and $23.49 in the Southern Synchronized Reserve Region.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU concludes from the analysis of the 2006 data that the PJM Regulation Market in 2006 was characterized by structural market power in 26 percent of the hours.[9] This conclusion is based on the results of the three pivotal supplier test. The MMU also concludes that PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition compared to the PJM Mid-Atlantic Regulation Market or the Western Region Regulation Market on a stand-alone basis.[10] The MMU also concludes that the performance of the Regulation Market was more competitive in calendar year 2006 than during the first 12 months of the Regulation Market, August 1, 2005, through July 31, 2006. These conclusions are based on improved HHI results and fewer hours during which there were three pivotal suppliers. The combined market results include the effects of the current mitigation mechanism which offer caps the two dominant suppliers in every hour. The MMU concludes that it would be preferable to retain the existing, experimental single PJM Regulation Market as the long-term market if appropriate mitigation can be implemented that addresses only the hours in which structural market power exists and which therefore provides an incentive for the continued development of competition.

With respect to mitigation, the MMU recommends that real-time, hourly market structure tests be implemented in the Regulation Market; that market power mitigation be applied only for hours in which the

9 This is the same conclusion reached in the MMU report on the first year of the Combined Regulation Market. See Market Monitoring Unit, "Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006" (October 18, 2006) <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20061018-mmu-regulation-market-report.pdf> (76.1 KB).

10 *2005 State of the Market Report* (March 8, 2006), pp. 260-263.

market structure is noncompetitive, and that market power mitigation be applied only to the companies failing the market structure tests. More specifically, the MMU recommends that the three pivotal supplier test be applied hourly in the Regulation Market using a market definition of all eligible offers less than or equal to 1.50 times the clearing price and that mitigation be applied to only those regulation-owning companies that fail the test in that hour.[11]

This more flexible and real-time approach to mitigation represents an improvement over the current approach to mitigation which requires cost-based offers from the dominant companies at all times. The proposed approach to mitigation also represents an improvement over prior methods of simply defining the market to be noncompetitive and limiting all offers to cost-based offers. The real-time approach recognizes that at times the market is structurally competitive and therefore no mitigation is required; that at times the market is not structurally competitive and mitigation is required, and that at times generation owners other than the designated dominant suppliers may have structural market power that requires mitigation. The MMU also recommends that the overall $100 regulation offer cap remain in effect. The retention of an overall offer cap together with a real-time, three pivotal supplier test for market structure is identical to PJM's current practice in the Energy Market.

The conclusions related to the structure of the Regulation Market are consistent with the conclusions reached in the *2005 State of the Market Report*, which stated: "The structure of the Mid-Atlantic Region and Western Region Regulation Markets was evaluated and the MMU concluded that these markets are not structurally competitive as they are characterized by a combination of one or more structural elements including high levels of supplier concentration, high individual company market shares, significant hours with pivotal suppliers and inelastic demand." The 2005 report also stated, "The Regulation Markets produced competitive results throughout calendar year 2005 based on the regulation market-clearing price."[12] The MMU cannot conclude that the Regulation Market in 2006 produced competitive results or noncompetitive results, based on our analysis of the relationship between the offer prices and marginal costs of units providing regulation. That is one of the reasons that the MMU recommends that all suppliers be required to provide cost-based regulation offers as part of real-time market power mitigation.

PJM's Synchronized Reserve Markets have worked effectively with offers based on marginal costs plus a margin and with all participants paid a market-clearing price based on the marginal offer including opportunity costs, despite the fact that these markets are characterized by high levels of seller concentration and inelastic demand.

The benefits of markets are realized under these approaches to Ancillary Service Markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market-clearing prices based on competitive offers that account explicitly and accurately for opportunity costs. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

PJM should continue to consider whether additional ancillary service markets need to be defined in order to ensure that the market is compensating suppliers for services when appropriate.

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

12 *2005 State of the Market Report* (March 8, 2006), pp. 250-251.

Overall, the MMU concludes that the Regulation Market's results cannot be determined to have been competitive or to have been noncompetitive. The MMU concludes that the Synchronized Reserve Markets' results were competitive.

Regulation Market

Market Structure

The PJM Regulation Market continued to mature in 2006. DSR participation was introduced in 2006, but no demand-side resources made offers in the Regulation Market in 2006.

Supply

The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called assigned regulation or cleared regulation. Assigned regulation is selected from regulation that is both offered and eligible.

Regulation capability is the sum of the maximum daily offers for each unit and is a measure of the total volume of regulation capability as reported by resource owners.

Regulation offered represents the level of regulation capability actually offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers are submitted on a daily basis.

Regulation offered and eligible represents the level of regulation capability offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit is included in regulation offered based on the daily offer and availability status, but that regulation capability is not eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. (The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market software.) As another example, the regulation capability of a unit is included in regulation offered if the owner of a unit offers regulation, but that regulation capability is not eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit is included in regulation offered, but that regulation capability is not eligible if the unit is not operating, unless the unit is a combustion turbine that meets specific operating parameter requirements.

Only those offers which are eligible to provide regulation in an hour are part of supply for that hour, and only eligible offers are considered by PJM for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the regulation market-clearing mechanism to provide regulation service for a given hour.

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2006 was 2.60. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was more than adequate to meet the regulation requirement.

Demand

Demand for regulation does not change with price (i.e., demand is price inelastic). The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand is also referred to in the *2006 State of the Market Report* as "required regulation."

The PJM regulation requirement was set by Reliability*First* Corporation in August 2006 to be 1.0 percent of the forecast-peak load for the entire day.[13] Prior to August, for the PJM Mid-Atlantic Region the regulation requirement for peak periods had been 1.1 percent of the peak-load forecast and for off-peak periods it had been 1.1 percent of the valley-load forecast.[14] During 2006 the PJM regulation requirements ranged from 692 MW to 1,434 MW. The average required regulation was 929 MW.

Market Concentration

Market Structure Definitions

The market structure analysis follows the FERC logic specified in the AEP Order.[15] The logic of the delivered price test is followed by calculating market share, HHI and pivotal supplier metrics for each market configuration.[16] The analysis presented here differs in two ways from the FERC's delivered price test. The delivered price test would start with the universe of regulation offered and eligible and then limit the analysis to the relevant competitive offers, defined as those offered and eligible units that could provide regulation at less than or equal to 1.05 times the clearing price. The analysis here also includes separately a broader definition of the relevant competitive offers, defined as those offered and eligible units that could provide regulation at less than or equal to 1.5 times the clearing price. In addition, the analysis here includes the results of the one and three pivotal supplier tests. In all cases, regulation must be both offered and eligible in an hour in order for it to be part of the market. This is termed economic capacity under the delivered price test.

The delivered price test may also be applied using available economic capacity, defined as gross supply by participants net of their load obligation. The fact that suppliers have load obligations may affect their incentives to exercise market power although not unambiguously. However, as the amount of load that will be served by the integrated utilities in the future is unknown given the unknown extent of retail competition, a reasonable approach is to evaluate the entire regulation supply, or economic capacity, as is done here.

The FERC's AEP Order indicates that failure of any one of the specified tests is adequate for a showing of market power including tests based on market concentration, market share and pivotal supplier analyses.

13 See Reliability*First* Corporation < http://www.reliabilityfirst.org/> (1 KB).

14 See PJM "Manual 11: Scheduling Operations," Revision 25 (August 19, 2005), p. 51.

15 107 FERC ¶ 61,018 (2004) (AEP Order) and 108 FERC ¶ 61,026 (2004) (AEP Order on Rehearing).

16 AEP Order at 105 et seq.

The analysis presented here goes further in order to analyze the significance of excess supply. The MMU applies the pivotal supplier test using one and three pivotal suppliers. In addition, when there are hours with one or three pivotal suppliers, the analysis also examines the frequency with which individual generation owners are in the pivotal group. If the hours that fail a pivotal supplier test have the same pivotal supplier(s) for a significant proportion of the hours, that information can be used to identify dominant suppliers.

The pivotal supplier test represents an analytical approach to the issue of excess supply. Excess supply, by itself, is not adequate to ensure a competitive outcome. A monopolist could have substantial excess supply, but the monopolist would not be expected to change its market behavior as a result. The same logic applies to a small group of dominant suppliers. However, if there is adequate supply without the three dominant suppliers to meet the demand, then the market can reasonably be deemed competitive.

PJM Regulation Market – 2006

During 2006 the PJM Regulation Market offer capability was 6,368 MW.[17] Total offer capability is a theoretical measure which is never actually achieved. The level of regulation resources offered on a daily level and the level of regulation resources both offered and eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2006 the average daily offer level was 3,926 MW or 62 percent of offer capability while the average hourly eligible offer level was 2,412 MW or 38 percent of offer capability. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible to be assigned during off-peak hours because fewer steam units are running during those hours. Table 6-1 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

Table 6-1 PJM regulation capability, daily offer and hourly eligible: Calendar year 2006

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	6,368	3,926	62%	2,412	38%
Off Peak	6,368	NA	NA	2,237	35%
On Peak	6,368	NA	NA	2,603	41%

The ratio of the hourly regulation supply offered and eligible to the hourly regulation requirement averaged 2.60 for PJM during 2006. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period.

17 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period without regard to the actual availability of the resource or to the day on which the maximum was offered.

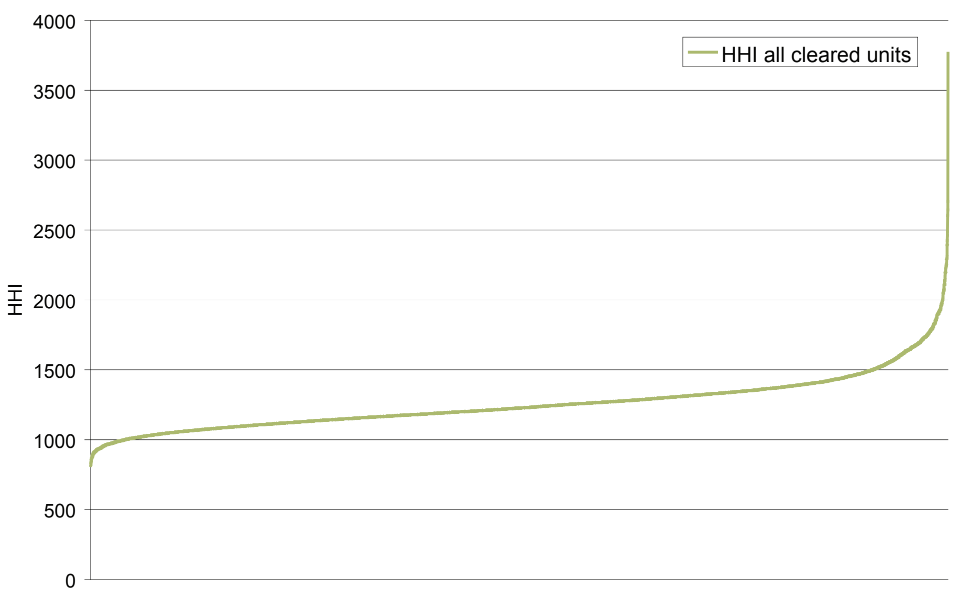
Hourly HHI values were calculated based upon cleared regulation. HHI values ranged from a maximum of 3763 to a minimum HHI of 816, with an average value of 1256, moderately concentrated under the FERC's definitions. Table 6-2 summarizes the 2006 PJM regulation market HHIs.

Table 6-2 PJM cleared regulation HHI: Calendar year 2006

Market Type	Minimum	Average	Maximum
All Units	816	1256	3763

The PJM Regulation Market exhibited consistent moderate market concentration with about 4 percent of the periods with an HHI less than 1000 and about 2 percent of the periods with an HHI greater than 1800. See the HHI duration curve in Figure 6-1.

Figure 6-1 PJM Regulation Market's HHI duration curve: Calendar year 2006



Market shares for cleared regulation for all of 2006 are listed in Table 6-3. The highest annual average hourly market share was 12 percent and the second and third highest annual average hourly market shares were both 11 percent. The largest hourly market share was 40 percent, and 43 percent of all hours had a maximum market share greater than 20 percent.

Table 6-3 Top three cleared regulation market shares: Calendar year 2006

Company Market Share Rank	Cleared Regulation Top Market Shares
1	12%
2	11%
3	11%

When all eligible regulating units whose price is less than, or equal to, the regulation market-clearing price (RMCP) times 1.05 are included in the definition of the relevant market, 7 percent of hours failed the one pivotal supplier test during 2006. (See Table 6-4.) This means that for 7 percent of hours the total regulation requirement could not be met in the absence of the largest supplier. One supplier of regulation was pivotal in 78 percent of the hours with one pivotal supplier and a second company was pivotal in 42 percent of the hours with one pivotal supplier. Seventy-nine percent of hours failed the three pivotal supplier test. One supplier of regulation was pivotal in 96 percent of the three pivotal supplier hours, a second company was pivotal in 67 percent and a third company was pivotal in 65 percent of three pivotal supplier hours.

Table 6-4 Regulation market pivotal suppliers: Calendar year 2006

Market Definition	Hours with One Pivotal Supplier (Percent)	Hours with Three Pivotal Suppliers (Percent)
Price ≤ RMCP * 1.05	7%	79%
Price ≤ RMCP * 1.5	0%	26%

When all eligible regulating units whose price is less than, or equal to, the market-clearing price times 1.5 are included in the definition of the relevant market, less than one percent of hours failed the one pivotal supplier test during 2006.[18] (See Table 6-4.) Twenty-six percent of hours failed the three pivotal supplier test. One company was pivotal in 98 percent of those hours, a second company was pivotal in 79 percent and a third company was pivotal in 72 percent of three pivotal supplier hours. Thus, in addition to failing the relevant pivotal supplier tests in a significant number of hours, the pivotal suppliers in the Regulation Market were the same suppliers in the majority of hours when the test was failed. This is a further indication that the structural market power issue in the Regulation Market was persistent and repeated during 2006. The MMU concludes from these results that the PJM Regulation Market in 2006 was characterized by structural market power. This conclusion is based on the pivotal supplier results, and in particular, on the results of the three pivotal supplier test with a market definition that includes all offers with a price less than or equal to 1.50 times the market-clearing price.

18 The number of hours which failed the three pivotal supplier test is rounded to zero.

Market Conduct

Offers

Generators wishing to participate in the PJM Regulation Market must submit regulation offers for specific units by 1800 EPT of the day before the operating day. The regulation offer price is subject to a $100 per MWh offer cap with the exception of the dominant suppliers, whose offers are capped at marginal cost plus $7.50 per MWh. As in any competitive market, regulation offers at marginal cost are considered to be competitive. In PJM, a $7.50 per MWh adder is considered to be consistent with competitive offers based on an analysis of historical offer behavior.

The offer price is the only component of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status (available, unavailable or self-scheduled); regulation capability; and high and low regulation limits. The Regulation Market is cleared on a real-time basis, and regulation prices are posted hourly throughout the operating day. The amount of self-scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made at least 30 minutes before each operating hour.

PJM's Regulation Market is cleared hourly, based upon both offers submitted by the units and the hourly lost opportunity cost of each unit calculated based on the forecast LMP at the location of each regulating unit.[19] The total offer price is the sum of the unit-specific offer and the opportunity cost. In order to clear the market, PJM ranks all offered and eligible regulating resources in ascending total offer price order, does the same for synchronized reserve and simultaneously determines the least expensive set of resources necessary to provide regulation, synchronized reserve and energy for the operating hour taking into account any resources self-scheduled to provide any of these services. The regulation market price that results is the RMCP, and the unit that sets this price is the marginal unit.

In 2006, offers from some regulation suppliers exceeded the competitive level. The competitive offer level for regulation, as for any other market, is the marginal cost of providing regulation. For the PJM Regulation Market, the marginal cost has been defined as the calculated cost plus a margin of $7.50 per MW. The cost of providing regulation has not been provided by suppliers. While the MMU recommended that the provision of such data be required and the PJM systems were created to allow the provision of cost data, provision of the data is not mandatory and suppliers do not currently provide the data. The MMU estimated hourly marginal costs for units that provided regulation during 2006.[20] Based on those estimates, 33 percent of unit daily offers exceeded marginal costs.

19 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. Opportunity cost is included in the market-clearing price.

20 See PJM "Manual 15: Cost Development Guidelines," Revision 7 (August 3, 2006).

Market Performance

Price

Figure 6-2 shows the daily average regulation market-clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received as payment the higher of the clearing price multiplied by the unit's assigned regulating capability, or the unit's regulation offer multiplied by its assigned regulating capability plus the individual unit's real-time opportunity cost.[21]

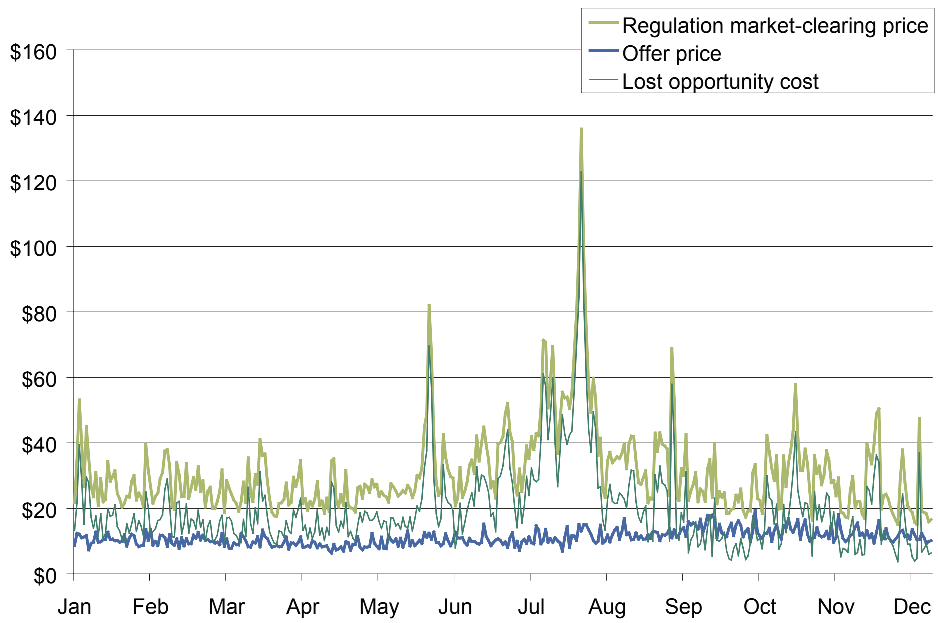
In 2006, offers at levels greater than the competitive level set the clearing price for regulation in 30 percent of hours. Of the 30 percent, 8 percent were between $0 and $7.50 per MW above the competitive level; 16 percent were between $7.50 and $10 per MW above the competitive level, and 6 percent were greater than $10 per MW above the competitive level. To put these results in context, the load-weighted, average offer price for all marginal units in the PJM Regulation Market during 2006 was $11.36, so an additional $7.50 per MW is a markup of about 66 percent. These results mean that the MMU cannot conclude that the Regulation Market results were competitive in 2006 or that the Regulation Market results were noncompetitive. The absence of a definitive conclusion is a result of the fact that the cost data are based on MMU estimates rather than data submitted by market participants. The MMU recommends that market participants be required to submit the cost of regulation, consistent with the definitions in PJM's "Cost Development Guidelines" when daily regulation offers are submitted in order both to permit analysis and to permit the recommended defined, targeted mitigation.[22]

Regulation credits are awarded to generation owners that have either self-scheduled or sold regulation into the market. Regulation credits for units self-scheduled to provide regulation are equal to the RMCP times the unit's self-scheduled regulating capability. Regulation credits for units that offered regulation into the market and were selected to provide regulation are the higher of the RMCP times the unit's assigned regulating capability, or the unit's regulation offer times its assigned regulating capability plus the opportunity cost that unit incurred. Although most units are paid RMCP times their assigned regulation MW, a substantial portion of the RMCP is the lost opportunity cost, based upon forecast LMP calculated for the marginal unit during market clearing. This means that a substantial portion of the total cost of regulation is determined by lost opportunity cost. As shown in Figure 6-2 more than half of the regulation price is the lost opportunity cost of the marginal unit. The balance of the RMCP is the unit's regulation offer. The load-weighted, average offer of the marginal unit for the PJM Regulation Market during 2006 was $11.36 per MW. The load-weighted, average LOC of the marginal unit for the PJM Regulation Market during 2006 was $23.06. In the PJM Regulation Market the marginal unit LOC averaged 70 percent of the RMCP.

21 See PJM "Manual 28: Operating Agreement, Accounting," Revision 27, Section 4, "Regulation Credits" (October 1, 2004), pp. 26-27. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and spinning. Real-time opportunity cost is calculated using real-time LMP.

22 See PJM "Manual 15: Cost Development Guidelines," Revision 7 (August 3, 2006).

Figure 6-2 PJM Regulation Market's daily average market-clearing price, lost opportunity cost and offer price: Calendar year 2006

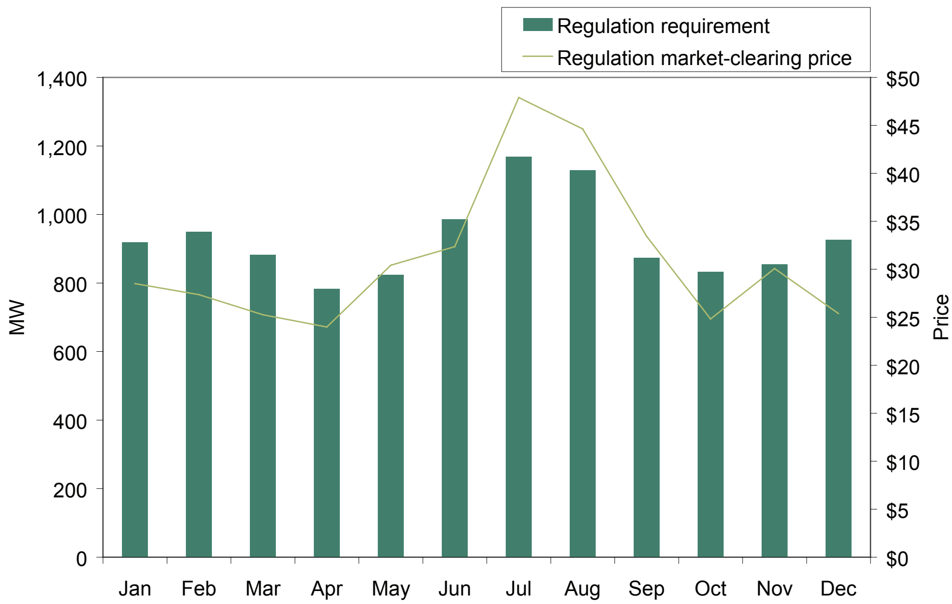


On a shorter-term basis, regulation prices follow a daily and weekly pattern. The supply of regulation is most plentiful between 0600 and 2300 EPT, Monday to Friday.

During weekends and NERC holidays, and weekdays between the hour ending at 2300 until the hour ending at 0800 (i.e., the off-peak hours), fewer steam generators are running and available to regulate. At times, units must be kept running for regulation that are not economic for energy, resulting in an increase in the LOC portion of the clearing price. At other times, expensive combustion turbine generators must be started to meet regulation requirements.

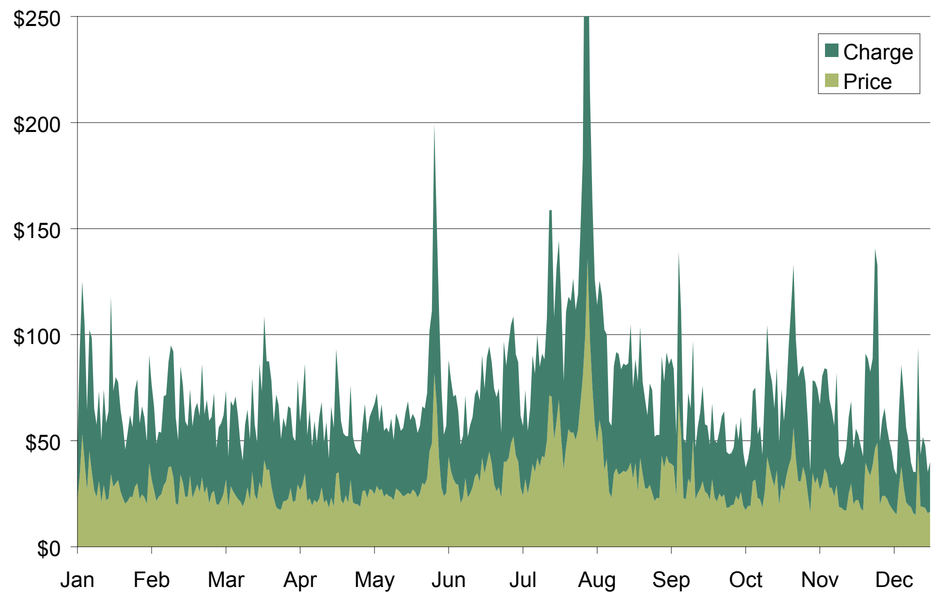
Figure 6-3 shows the level of demand for regulation by month in 2006 and the corresponding level of regulation price.

Figure 6-3 Monthly average regulation demand (required) vs. price: Calendar year 2006



Units which provide regulation are paid the higher of the RMCP or their offer plus their unit-specific opportunity cost. The offer plus the unit-specific opportunity cost may be higher than the RMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the RMCP, unit-specific opportunity costs will be higher than forecast. Such higher LMPs can be local, because of congestion, or more general, if system conditions change. Other reasons include units that must be redispatched because of constraints or unanticipated unit performance problems. When some units are paid more than the RMCP based on unit-specific lost opportunity costs, the result is that PJM's regulation charge per MWh is higher than the RMCP. Figure 6-4 compares the regulation charge per MWh with the regulation-clearing price to show the difference between the price of regulation and the total charge for regulation.

Figure 6-4 Daily average regulation charge and price: Calendar year 2006



For all of 2006, the average regulation price was $32.69. The average regulation charge was $44.98. The difference between the regulation market price and the actual charge for regulation was significant in 2006. The charge for regulation was 37.6 percent higher than the market price of regulation. While the reasons are not yet fully understood, the payment of a larger portion of regulation charges on a unit-specific basis rather than on the basis of a market-clearing price is a cause for concern as it results in a weakened market price signal to the providers of regulation.

Synchronized Reserve Market

Market Structure

The PJM Synchronized Reserve Market includes the Mid-Atlantic Region's Synchronized Reserve Market, the Western Region's Synchronized Reserve Market, the ComEd Control Zone's Synchronized Reserve Market and the Southern Region's Synchronized Reserve Market.

Supply

Synchronized reserve is an ancillary service defined as generation or curtailable load that is synchronized to the system and capable of producing output within 10 minutes. Synchronized reserve can, at present, be provided by a number of resources, including steam units with available ramp, condensing hydroelectric units, condensing combustion turbines (CTs) and CTs running at minimum generation. As of August 2006, synchronized reserve can also be supplied by DSR resources subject to the limit that they provide no more than 25 percent of the total synchronized reserve requirement. Synchronized reserve DSR resources can be provided by behind the meter generation or can be provided by reductions in load.

All of the units that participate in the Synchronized Reserve Markets are categorized as Tier 2 synchronized reserve. Tier 1 resources are those units that are online, following economic dispatch and able to respond to a spinning event by ramping up from their present output. All units operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 synchronized reserve. Tier 2 resources include units that are backed down to provide synchronized reserve capability, condensing units synchronized to the system and available to increase output and demand-side resources.

Under the synchronized reserve market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed.[23] Tier 1 synchronized reserve payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the synchronized reserve energy premium less the hourly integrated LMP. The synchronized reserve energy premium is defined as the average of the five-minute LMPs calculated during the spinning event plus $50 per MWh. All units called on to supply Tier 1 or Tier 2 synchronized reserve have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response.

Under the synchronized reserve market rules, Tier 2 synchronized reserve resources are paid to be available as synchronized reserve, regardless of whether the units are called upon to generate in response to a spinning event and are subject to penalties if they do not provide synchronized reserve when called. The price for Tier 2 synchronized reserve is determined in a market for Tier 2 synchronized reserve resources. This market is termed the Synchronized Reserve Market. Several steps are necessary before the hourly Synchronized Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit; 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. If synchronized reserve requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined at least 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit-order price of the highest-priced Tier 2 resource needed to meet the demand for synchronized reserve requirements, the marginal unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[24]

The synchronized reserve offer price submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[25, 26] The market-clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the start-up cost (if the unit is not running) and the unit's lost opportunity cost. LOC is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. LOC for demand-side resources is always zero. All units cleared in the Synchronized Reserve Markets are paid the higher of either the market-clearing price or the unit's synchronized reserve offer plus the unit-specific LOC and the cost of energy use incurred.

The Synchronized Reserve Markets for the Mid-Atlantic Region, the Western Region, the ComEd Control Zone and the Southern Region all operate under similar business rules. The Tier 2 Synchronized Reserve Market in each of PJM's synchronized reserve areas is cleared on cost-based offers because the structural

23 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 60.

24 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price has been established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.

25 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 61.

26 See PJM "Manual 15: Cost Development Guidelines," Revision 7 (August 3, 2006), p. 37.

conditions for competition do not exist. The market structure issue can be even more severe when the Synchronized Reserve Market becomes local because of transmission constraints.

For the PJM Mid-Atlantic Region, the offered and eligible excess supply ratio was 1.64. For the ComEd Control Zone, the ratio was 1.46.[27] These excess supply ratios are determined using the administratively determined requirement for synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower because there is usually a significant amount of Tier 1 synchronized reserve available.

Demand

The demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve control area's synchronized reserve requirement for the period. The total synchronized reserve requirement is different for each of the four, regional Synchronized Reserve Markets.[28] For the PJM Mid-Atlantic Synchronized Reserve Market, the requirement is 75 percent of the largest contingency in the region, provided that double the remaining 25 percent of the largest contingency is available as nonsynchronized, 10-minute reserve. For the ComEd Synchronized Reserve Market, the requirement is 50 percent of the ComEd Control Zone's load ratio share of the largest contingency in the North American Electric Reliability Council's (NERC) Mid-America Interconnected Network, Inc. (MAIN) Region. For the PJM Western Synchronized Reserve Region, the requirement is 1.5 percent of the daily peak-load forecast. For the PJM Southern Synchronized Reserve Region, the requirement is the Dominion Control Zone's load ratio share of the largest system contingency within the Virginia and Carolinas Area (VACAR), minus the available 15-minute quick start capability within the PJM Southern Synchronized Reserve Region.

Computed in accordance with the requirements above, the 2006 average MW synchronized reserve requirement was: 1,109 MW for the PJM Mid-Atlantic Region; 222 MW for the ComEd Control Zone; 423 MW for the Western Region; and 9 MW for the Southern Region.

27 The Synchronized Reserve Markets in the Western Region and Southern Region cleared in so few hours that related data for those markets are not meaningful.
28 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 63.

Figure 6-5 and Figure 6-6 show the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW purchased during 2006 for the PJM Mid-Atlantic and the ComEd Synchronized Reserve Markets. Results for the Western Synchronized Reserve Region and the Southern Synchronized Reserve Region are not shown because Tier 2 synchronized reserve MW purchases were insignificant in those areas during 2006.

Figure 6-5 PJM's Mid-Atlantic Tier 2 Synchronized Reserve Region's monthly required vs. purchased: Calendar year 2006

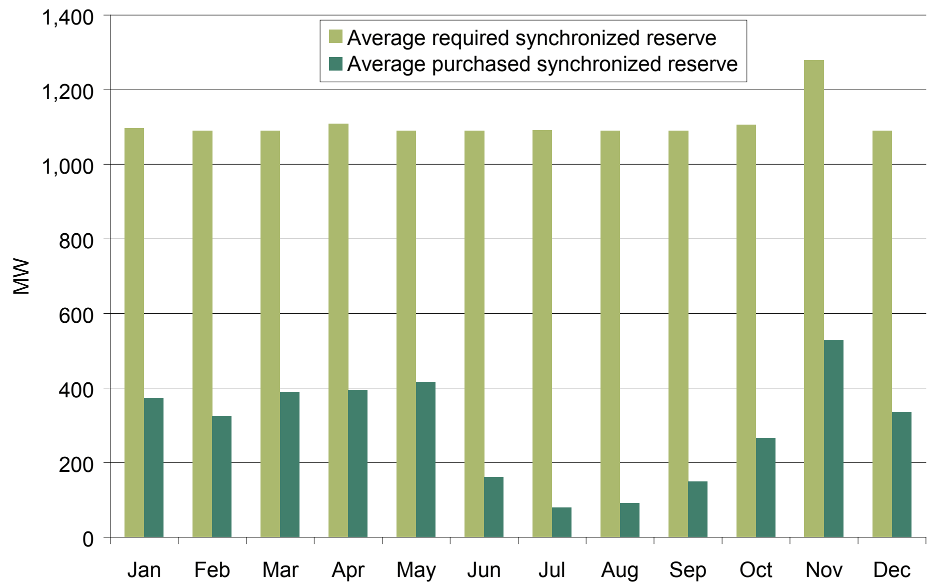
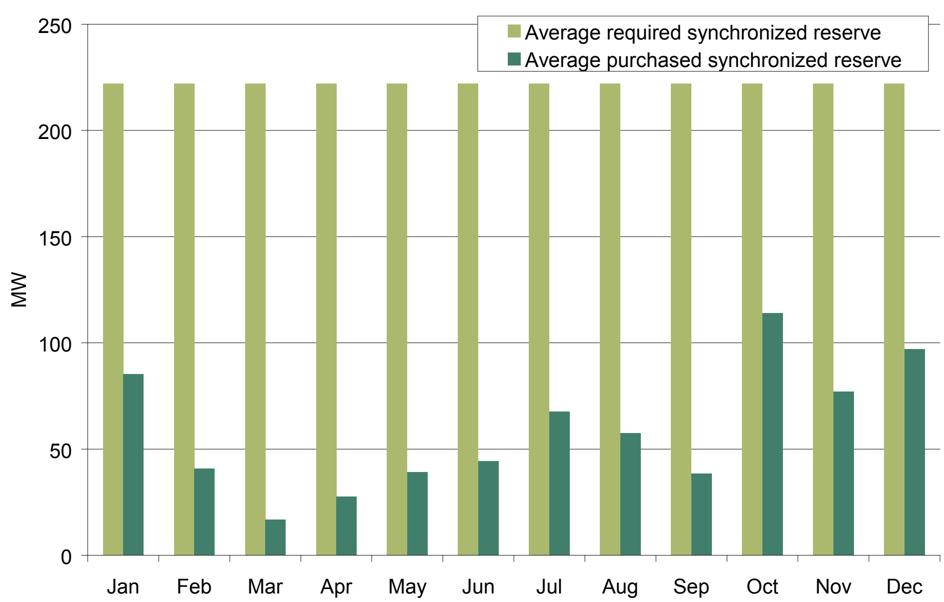


Figure 6-6 PJM's ComEd Tier 2 Synchronized Reserve Zone's monthly required vs. purchased: Calendar year 2006



The difference between the required amount of synchronized reserve and the amount of Tier 2 synchronized reserve purchased is the amount of Tier 1 synchronized reserve available on the system. During the first quarter of 2006, PJM dispatchers noticed that actual Tier 1 MW generated in response to spinning events was higher than estimated Tier 1 MW. PJM analysis resulted in improved Tier 1 estimating procedures and higher Tier 1 estimates.[29] The changes to Tier 1 estimates were implemented in June and resulted in a drop in the amount of Tier 2 synchronized reserve MW purchased.[30] (See Figure 6-5.)

Synchronized reserve MW requirements are different for each of the four synchronized reserve areas in PJM. These differences are the result of specifications from regional reliability councils, reserve-sharing arrangements with neighboring control areas and the types of generation available in the control area.

The Southern Synchronized Reserve Region is a member of the VACAR subregion of NERC's Southeastern Electric Reliability Council (SERC). VACAR specifies that available, 15-minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements. The amount of 15-minute quick start reserve available in VACAR is sufficient to make Tier 2 synchronized reserve demand zero for most hours.

Similarly, in the Western Synchronized Reserve Region most of the required synchronized reserve is available as Tier 1 from large, frequently running baseload units, reducing its Tier 2 synchronized reserve demand to zero in most hours.

For the PJM Mid-Atlantic Synchronized Reserve Region, the synchronized reserve requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. Mid-Atlantic Area Council (MAAC) standards currently set that amount at 75 percent of the largest contingency in that Synchronized Reserve Zone provided that double the remaining 25 percent is available as non-synchronized 10-minute reserve.[31] The ComEd Synchronized Reserve Control Zone requirement is defined as 50 percent of ComEd's load ratio share of the largest system contingency within MAIN. For the PJM Mid-Atlantic Region the hourly synchronized reserve requirement was usually 863 MW (19.5 percent of total hours) during off-peak hours and 1,150 MW (73.7 percent of total hours) during on-peak hours. Sometimes temporary grid conditions such as maintenance outages can cause double contingencies so there were times throughout the year when the on-peak synchronized reserve requirement was 1,360 MW (5.8 percent of total hours). The average hourly synchronized reserve required for the PJM Mid-Atlantic Region was 1,109 MW. In the ComEd Control Zone, the hourly requirement was always 222 MW.

29 See Stanley Williams, manager, PJM Performance Compliance, "Spinning Market Generator Performance," PJM Market Implementation Committee Meeting (August 8, 2006). The analysis showed that the actual Tier 1 response during spinning events was 171 percent of PJM's estimate of Tier 1 response.

30 See PJM "Manual 12: Dispatching Operations," Revision 13 (May 26, 2006), p. 68.

31 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 63.

Market Concentration

There are several metrics used to measure market concentration. All of them indicate a concentrated market. Market share data show that the Synchronized Reserve Market in both the PJM Mid-Atlantic Region and the ComEd Control Zone is dominated by a relatively small number of companies. (See Table 6-5 and Table 6-6.)

Table 6-5 The PJM Mid-Atlantic Region's Tier 2 cleared synchronized reserve market shares: Calendar year 2006

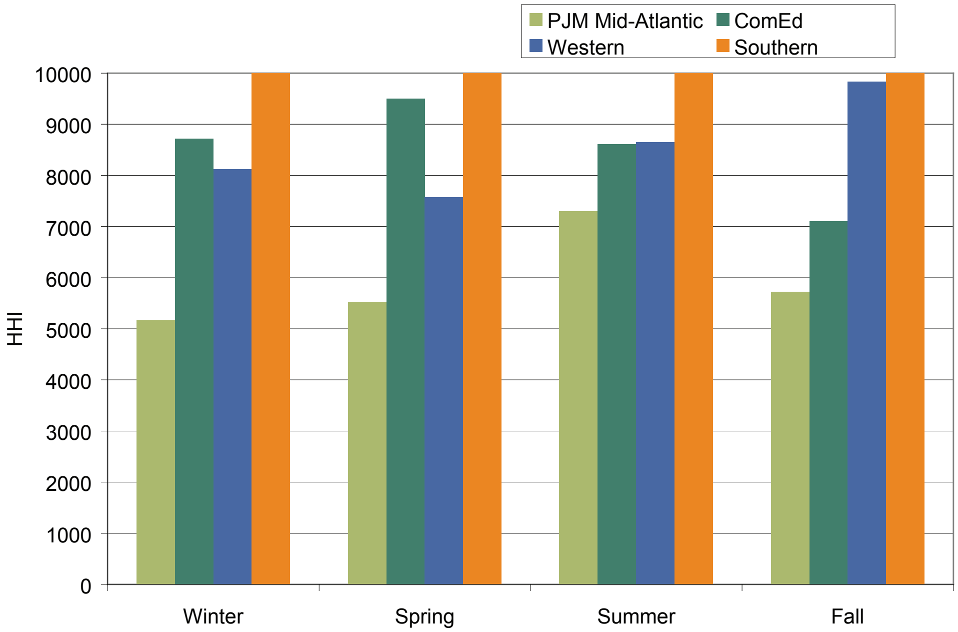
Company Market Share Rank	Cleared Synchronized Reserve: All Units
1	43%
2	19%
3	18%
4	10%
5	2%

Table 6-6 The PJM ComEd Control Zone's Tier 2 cleared synchronized reserve market shares: Calendar year 2006

Company Market Share Rank	Cleared Synchronized Reserve: All Units
1	59%
2	16%
3	15%

The cleared Tier 2 Synchronized Reserve Markets for all four geographic areas are highly concentrated. (See Figure 6-7 which also provides seasonal details.) During calendar year 2006, in the PJM Mid-Atlantic Region average HHI for cleared Tier 2 synchronized reserve was 5686. In the ComEd Control Zone during 2006 the average HHI for cleared Tier 2 synchronized reserve was 8305. In the Western Region the average HHI for cleared Tier 2 synchronized reserve was 7944. In the Southern Region the HHI was 10000.

Figure 6-7 Cleared Tier 2 synchronized reserve market seasonal HHI: Calendar year 2006



The pivotal supplier metric provides an analytical approach to the issue of excess supply on the synchronized reserve market-clearing price (SRMCP).[32] (See Table 6-7.) While there are only a few major suppliers, the supply of eligible Tier 2 synchronized reserve is generally much larger than the hourly demand. When the relevant market is defined to include all offers at less than or equal to 1.05 times the clearing price, in the Mid-Atlantic Region there is a single pivotal supplier in 24 percent of the hours and three pivotal suppliers in 92 percent of the hours. When the relevant market is defined to include all offers at less than or equal to 1.50 times the clearing price, in the Mid-Atlantic Region there is a single pivotal supplier in 3 percent of the hours and three pivotal suppliers in 66 percent of the hours. The results are comparable for the ComEd Control Zone with more hours failing the single and three pivotal supplier tests. The pivotal supplier results indicate that the markets for synchronized reserve in the Mid-Atlantic Region and the ComEd Control Zone are not structurally competitive.

Table 6-7 The Mid-Atlantic Region's and the ComEd Control Zone's Tier 2 synchronized reserve market percent pivotal supplier hours: Calendar year 2006

Market Definition	One Pivotal Supplier (Percent Hours)	Three Pivotal Supplier (Percent Hours)
PJM Mid-Atlantic; Price ≤ SRMCP * 1.5	3%	66%
PJM Mid-Atlantic; Price ≤ SRMCP * 1.05	24%	92%
ComEd; Price ≤ SRMCP * 1.5	45%	100%
ComEd; Price ≤ SRMCP * 1.05	48%	100%

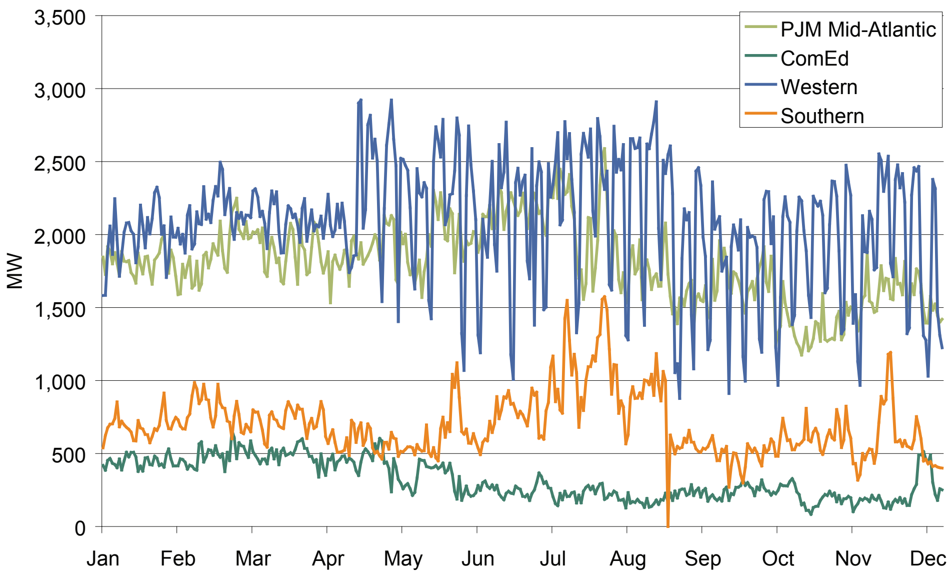
32 See *2006 State of the Market Report*, Volume II, Appendix J, "Three Pivotal Supplier Test."

Market Conduct

Offers

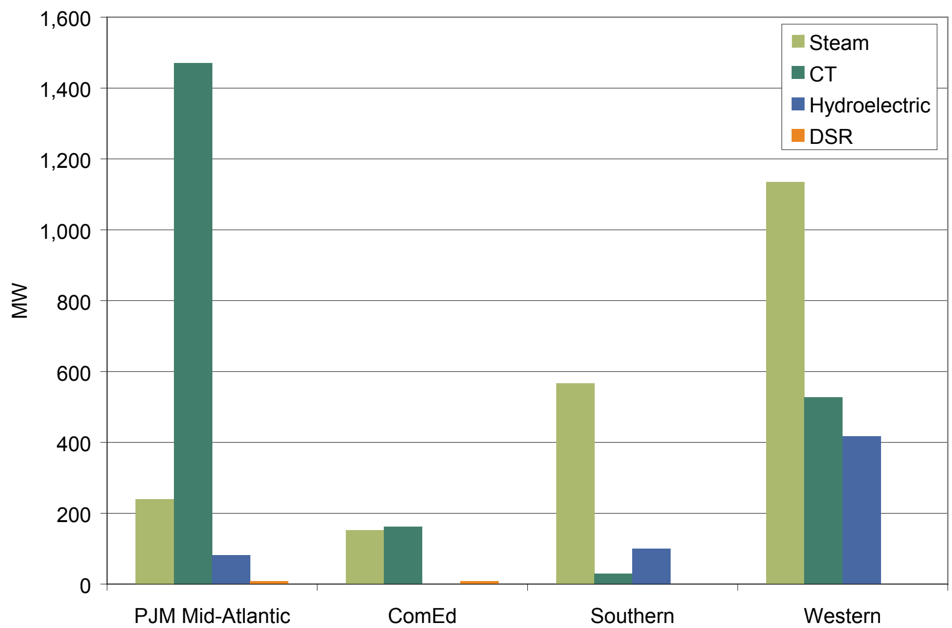
Figure 6-8 shows the daily average hourly eligible Tier 2 synchronized reserve offers. The level of eligible synchronized reserve displays considerable variability because it is calculated hourly and reflects current market and grid conditions, including LMP, unit dispatch and system constraints.

Figure 6-8 Tier 2 synchronized reserve average hourly eligible volume (MW): Calendar year 2006



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 6-9 shows average eligible MW volume by ancillary service area and unit type.

Figure 6-9 Average daily Tier 2 synchronized reserve eligible by unit type (MW): Calendar year 2006



Market Performance

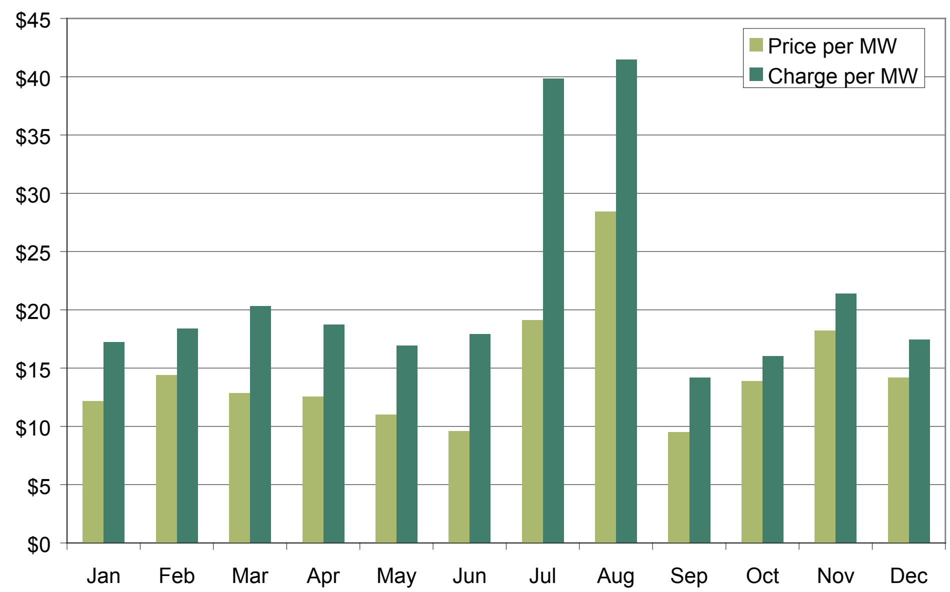
Price

Figure 6-10 shows the load-weighted, average Tier 2 SRMCP and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is called the synchronized reserve market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit-specific LOC. The offer plus the unit-specific LOC may exceed the SRMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the SRMCP, unit-specific LOC will be higher than forecast. Such higher LMPs can be local, because of congestion, or more general, if system conditions change. The additional costs of non-economic dispatch are added to the total cost of synchronized reserve. When some units are paid the value of their offer plus their unit-specific LOC the result is that PJM's synchronized reserve cost per MWh is higher than the SRMCP.

The load-weighted, average price for synchronized reserve in the PJM Mid-Atlantic Region during 2006 was $14.57. The load-weighted, average price for synchronized reserve in the ComEd Control Zone was $16.69. Only 6 percent of hours in the Western Region cleared the Synchronized Reserve Market in 2006 with an average price of $9.14. Less than 1 percent of hours in the Southern Region cleared Synchronized Reserve Market in 2006 with an average price of $23.49.

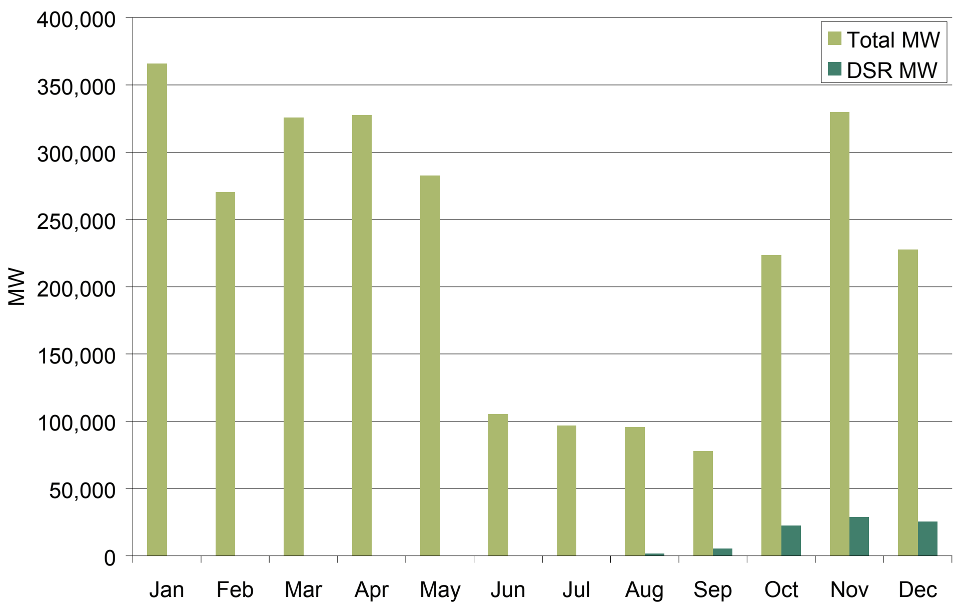
The difference between the Tier 2 synchronized reserve market price and the actual charge for Tier 2 synchronized reserve was significant in 2006. The load-weighted, average monthly price of Tier 2 synchronized reserve for the PJM Mid-Atlantic Region for 2006 was $14.57. The load-weighted, average monthly charge for Tier 2 synchronized reserve for PJM for 2006 was $21.65. The charge for Tier 2 synchronized reserve was 49 percent higher than the market price of Tier 2 synchronized reserve. While the reasons are not yet fully understood, the payment of a larger portion of synchronized reserve charges on a unit-specific basis rather than on the basis of a market-clearing price is a cause for concern as it results in a weakened market price signal to the providers of Tier 2 synchronized reserve.

Figure 6-10 Comparison of PJM Tier 2 synchronized reserve price and charge: Calendar year 2006



Demand-side resources began participating in the Synchronized Reserve Markets in August 2006. Figure 6-11 shows total monthly synchronized reserve cleared MW and cleared MW for DSR synchronized reserve. Figure 6-11 also shows a drop in the amount of synchronized reserve cleared starting in June. PJM changed reserve reporting procedures which resulted in higher estimated Tier 1 reserve which in turn reduced the amount of Tier 2 synchronized reserve needed to satisfy the synchronized reserve requirement.[33] Cleared Tier 2 synchronized reserve MW increased in November as the result of a bus outage resulting in a double contingency from November 7 through November 28. For every hour during this period the amount of synchronized reserve required was 1,360 MW as opposed to the usual 1,150 MW during on-peak and 863 MW during off-peak periods.

Figure 6-11 PJM Tier 2 synchronized reserve cleared MW: Calendar year 2006



Availability

A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. None of PJM's Synchronized Reserve Markets had significant deficits during 2006.

33 See PJM "Manual 12: Dispatching Operations," Revision 13 (May 26, 2006), p. 29.

SECTION 7 – CONGESTION

Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy to some loads. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[1] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying features of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would permit direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[2]

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.[3]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $489 million or 23 percent, from $2.092 billion in calendar year 2005 to $1.603 billion in calendar year 2006. Day-ahead congestion costs decreased by $650 million or 28 percent, from $2.357 billion in calendar year 2005 to $1.707 billion in calendar year 2006. Balancing congestion costs increased by $161 million or 61 percent, from -$265 million in calendar year 2005 to -$104 million in calendar year in 2006. Total congestion costs have ranged from 7 percent to 10 percent of PJM annual total billings since 2002. Congestion costs were 8 percent of total PJM billings for 2006, compared to 9 percent in 2005. Total PJM billings for 2006 were $20.945 billion, a 7 percent decrease from the $22.630 billion billed in 2005.

1 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean that the next unit in merit order cannot be used and that a higher cost unit must be used in its place.

2 See *2006 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

3 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."

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2006, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load.

- **Hedged Congestion.** The total of ARR and FTR revenues hedged 99 percent of the congestion costs in the Day-Ahead and Balancing Energy Market within PJM for the 2005 to 2006 planning period and 98.4 percent of the congestion costs in PJM in the first seven months of the 2006 to 2007 planning period.[4] The total value of the hedge provided by FTRs reflects the fact that FTRs were paid at 91 percent of the target allocation level for the 12-month planning period that ended May 31, 2006. FTRs were paid at 100 percent of the target allocation level through December 31, 2006, for the planning period ending May 31, 2007. ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level as aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

LMP Differentials and Facility or Zonal Congestion

- **LMP Differentials.** To provide an approximate indication of the geographic dispersion of congestion costs, LMP differentials were calculated for control zones in the PJM Mid-Atlantic and Western Regions as they existed at year end as the difference between zonal LMP and the Western Hub LMP. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the Bedington–Black Oak Interface, the Kammer and Wylie Ridge transformers and the 5004/5005 Interface. These constraints generally had the effect of increasing prices in eastern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

- **Congested Facilities.** As was the case in 2005, congestion frequency was significantly higher in the Day-Ahead as compared to the Real-Time Market in 2006.[5] Day-ahead congestion frequency increased slightly in calendar year 2006 as compared to 2005. In 2006, there were 56,299 day-ahead, congestion-event hours as compared to 55,705 congestion-event hours in 2005. Day-ahead, congestion-event hours increased on lines and Midwest Independent Transmission System Operator, Inc. (Midwest ISO) flowgates, while transformers and interfaces saw decreases. Real-time congestion frequency decreased in calendar year 2006 as compared to 2005. In 2006, there were 19,510 real-time, congestion-event hours as compared to 24,109 congestion-event hours in 2005. Real-time, congestion-event hours increased on Midwest ISO flowgates, while lines, transformers and interfaces saw decreases. The Bedington–Black Oak Interface was the largest contributor to congestion costs in both 2005 and 2006 and, with $492 million in total congestion costs, accounted for 31 percent of the total PJM congestion costs in 2006. The top four constraints in terms of congestion costs together contributed $780 million, or 49 percent, of the total PJM congestion costs in 2006. The top four constraints also included the 5004/5005 Interface, Mount Storm–Pruntytown and Kanawha–Matt Funk lines.

4 See *2006 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-20, "ARR and FTR congestion hedging: Planning periods 2005 to 2006 and 2006 to 2007."

5 Prior state of the market reports measured real-time congestion frequency using the convention that a congestion-event hour exists if the particular facility is constrained for four or more of the 12 five-minute intervals comprising that hour. In the *2006 State of the Market Report*, in order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. Comparisons to previous periods use the new standard for both current and prior periods.

- **Zonal Congestion.** In calendar year 2006, the AP Control Zone experienced the highest congestion cost of any control zone in PJM. The $340 million in congestion costs in the AP Control Zone represented a 26 percent decrease from the $460 million in congestion costs the zone had experienced in 2005. The Bedington–Black Oak Interface and Meadow Brook transformer constraints together contributed $208 million, or 61 percent of the total AP Control Zone congestion cost. The AEP Control Zone had the second highest congestion cost in PJM in 2006. The $242 million in congestion costs in the AEP Control Zone represented an 18 percent increase from the $204 million in congestion costs the zone had experienced in 2005. The Kanawha–Matt Funk line and the Bedington–Black Oak Interface constraints together contributed $104 million, or 43 percent of the total AEP Control Zone congestion cost.

Economic Planning Process

- **Process Revision.** PJM's current planning process for economic transmission expansions provides that when unhedgeable congestion reaches certain thresholds, a one-year market window is opened during which time market solutions may be proposed by market participants. In its September 8, 2006, filing, PJM proposed to replace the unhedgeable congestion approach with an evaluation based on additional congestion metrics. The metrics will be applied to evaluating all types of transmission projects, including whether to modify or accelerate reliability enhancements already in the Regional Transmission Expansion Plan (RTEP) that could also relieve one or more economic constraints and whether to propose new, economic transmission projects that could relieve one or more economic constraints. PJM will also evaluate whether demand response resources or new generation could eliminate the need for an economic upgrade. The revised economic planning process includes enhanced stakeholder participation. The proposed economic planning revisions incorporate improvements over the existing process but require ongoing development. The approach to weighting and evaluating the metrics in the context of actual transmission projects will require substantial effort. New transmission projects, and the lack of existing transmission, can have significant impacts on the PJM markets and the goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market-driven processes as much as is practicable.

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Total congestion costs decreased by $489 million or 23 percent, from $2.092 billion in calendar year 2005 to $1.603 billion in calendar year 2006. Day-ahead congestion costs decreased by $650 million or 28 percent, from $2.357 billion in calendar year 2005 to $1.707 billion in calendar year 2006. Balancing congestion costs increased by $161 million or 61 percent, from -$265 million in calendar year 2005 to -$104 million in calendar year in 2006. Congestion costs were significantly higher in the Day-Ahead Market than in the Balancing Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. In the Day-Ahead Market in 2006, there were 56,299 congestion-event hours compared to 55,705 congestion-event hours in 2005. In the Real-Time Energy Market in 2006, there were 19,510 congestion-event hours compared to 24,109 congestion-event hours in 2005.

As a result of the geographic growth of PJM, efficient redispatch displaced the less efficient management of borders via transmission loading relief (TLR) procedures and ramp limits. Redispatch is more efficient and, at the same time, revealed the underlying inability of the transmission system to transfer the lowest-cost energy on the system to all parts of the system for all hours. The details are revealed in the analysis of temporal patterns of congestion and of congested facilities and zonal congestion. That information, made explicit over the broad PJM footprint for the first time, is an essential input to a rational market and planning process. PJM has made significant steps in the transmission planning process.

ARRs and FTRs served as an effective hedge against congestion. In total, ARR and FTR revenues hedged 99 percent of congestion costs in the Day-Ahead and Balancing Energy Market within PJM for the 2005 to 2006 planning period and 98.4 percent of the congestion costs in PJM in the first seven months of the 2006 to 2007 planning period. FTRs were paid at 91 percent of their target allocation for the planning year ended May 31, 2006, and at 100 percent for the first seven months of the current planning year.

One constraint accounted for almost a third of total congestion costs in 2006 and the top four constraints accounted for about half of total congestion costs. The largest constraint has been a persistent source of large congestion costs for several years. This suggests that these constraints should receive special attention in the economic planning process. The Bedington–Black Oak Interface was the largest contributor to congestion costs in both 2005 and 2006 and, with $492 million in total congestion costs, accounted for 31 percent of the total PJM congestion costs in 2006. The top four constraints in terms of congestion costs together accounted for 49 percent of the total PJM congestion costs in 2006.

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market. Transmission congestion charges in the Day-Ahead Energy Market can be directly hedged by FTRs. Balancing Market congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the Day-Ahead Energy Market.[6]

Total congestion charges are the sum of the implicit, explicit and spot market congestion charges incurred in the Day-Ahead Market and the Balancing Market, minus any negatively valued FTR target allocations.[7]

- **Implicit Congestion Charges.** Implicit congestion charges are the net congestion charges to serve load from owned generation and contractual energy purchases. These charges are incurred by network service customers in delivering their own generation or bilateral purchases to their load and equal the difference between a participant's load charges and generation credits, less the participant's spot market bill. In the Day-Ahead Energy Market, load charges are calculated as the sum of the demand at every bus times the bus LMP. Demand includes load, decrement bids and sale transactions. Generation credits in the Day-Ahead Energy Market are calculated as the sum of the supply at every bus times the bus LMP, where supply includes generation, increment bids and purchase transactions. In the Balancing

6 The terms "congestion charges" and "congestion costs" are both used to refer to the costs associated with congestion. The term "congestion charges" is used in PJM Settlements documents.

7 See PJM "Manual 28: Operating Agreement Accounting," Revision 36 (January 1, 2007), p. 42.

Energy Market, load charges and generation credits are calculated using the differences between day-ahead and real-time demand and supply and valuing congestion using real-time LMP.

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

- **Spot Market Congestion Charges**. Spot congestion charges are the net congestion charges associated with spot market purchases and sales. These charges equal the difference between total spot market purchase payments and total spot market sales revenues.

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone. In prior state of the market reports, the analysis of specific constraints focused on real-time congestion frequency.[8]

Congestion costs can be both positive and negative. Congestion is defined with respect to the system marginal price (SMP), which is the single system price that would occur in the absence of any congestion. When a transmission constraint occurs, congestion is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion component of LMP (CLMP) is positive or negative. The CLMP measures the difference between the actual LMP that results from transmission constraints and the unconstrained SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.

Total Calendar Year Congestion

While congestion charges are the primary source of funding to meet FTR target allocations, they are only a part of total FTR funding. Annual congestion charges may be greater than, less than, or equal to, total FTR revenues depending upon adjustments made to total FTR revenues. A year-to–year comparison of congestion charges and total FTR revenues shows that congestion charges were greater than FTR revenues in 2002 and less than FTR revenues in 2003 through 2006. (See Table 7-1 and Table 7-2.) Table 7-3 shows the detailed components of FTR revenues including congestion charges and other adjustments for calendar year 2006.

Table 7-1 shows that FTR revenues have ranged from 7 percent to 10 percent of total, annual PJM billings since 2002. Annual FTR revenues decreased by 23 percent in 2006 and were 8 percent of total PJM billings in 2006. [9, 10]

8 The MMU has developed new analytical tools that permit the analysis of congestion cost by zone and constraint in this report.

9 Calculated values shown in Section 7, "Congestion," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

10 FTR revenue data may be adjusted by the PJM Settlements Department after the publication of the state of the market report. The data here are current for 2006 and final for prior years.

Table 7-1 Total annual PJM FTR revenues [Dollars (millions)]: Calendar years 2002 to 2006

	FTR Revenues	Percent Change	Total PJM Billing	Percent of PJM Billing
2002	$430	NA	$4,700	9%
2003	$499	16%	$6,900	7%
2004	$808	62%	$8,700	9%
2005	$2,158	167%	$22,630	10%
2006	$1,653	(23%)	$20,945	8%
Total	$5,547		$63,875	9%

Congestion charges are comprised of hourly congestion revenue and net negative congestion. Congestion charges have ranged from 7 percent to 10 percent of annual total PJM billings since 2002. Congestion charges decreased by 23 percent in 2006 as compared to 2005 and were equal to 8 percent of total PJM billings in 2006. Table 7-2 shows total congestion by year from 2002 through 2006. Total congestion charges were $1.60 billion in calendar year 2006, a 23 percent decrease from $2.09 billion in calendar year 2005.

Table 7-2 Total annual PJM congestion [Dollars (millions)]: Calendar years 2002 to 2006

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2002	$453	NA	$4,700	10%
2003	$464	2%	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
Total	$5,362		$63,875	8%

Table 7-3 shows the composition of FTR target allocations and FTR revenues for calendar year 2006. FTR targets are composed of FTR target allocations and associated adjustments. Other adjustments may be made for items such as modeling changes or errors.

FTR revenues are primarily comprised of hourly congestion revenue and net negative congestion. FTR revenues also include ARR excess which is the difference between ARR target allocations and FTR auction revenues. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Total congestion charges appearing in Table 7-2 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[11] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G)[12] and Consolidated Edison Company of New York (Con Edison) resulted in a reimbursement of $2 million in congestion charges to Con Edison in calendar year 2006.[13, 14]

Table 7-3 Total annual PJM FTR revenue detail [Dollars (millions)]: Calendar year 2006

Accounting Element	
ARR Information	
ARR Target Allocations	$1,183.6
FTR Auction Revenue	$1,210.9
ARR Excess	$27.4
FTR Targets	
FTR Target Allocations	$1,676.9
Adjustments:	
Adjustments to FTR Target Allocations	($1.6)
Total FTR Targets	$1,675.3
FTR Revenues	
ARR Excess	$27.4
Competing Uses	$1.2
Hourly Congestion Revenue	
Day-Ahead	$1,707.1
Balancing	($103.8)
Midwest ISO M2M (Credit to PJM Minus Credit to Midwest ISO)	$2.5
CEPSW Wheel Congestion Credit	($2.0)
Adjustments:	
Excess Revenues Carried Forward Into Future Months	$15.3
Excess Revenues Distributed Back to Previous Months	$6.6
Other Adjustments to FTR Revenues	($1.5)
Total FTR Revenues	$1,652.5
Excess Revenues Distributed to Other Months	($40.1)
Excess Revenues Distributed to Firm Demand Holders	$0.0
Total FTR Congestion Credits	$1,612.4
Total Congestion Credits on Bill (Includes CEPSW & End-of-Year Distribution)	$1,614.4
Remaining Deficiency	$62.9

11 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 31, 2003), Substitute Original Sheet No. 66 <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,331 KB).

12 Prior state of the market reports indicated that this contract is an agreement between Con Edison and PSEG. The contract is between Con Edison and PSE&G, a wholly owned subsidiary of PSEG.

13 111 FERC ¶ 61,228 (2005).

14 See *2006 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Con Edison and PSE&G Wheeling Contracts 2006 Update."

Monthly Congestion

Table 7-4 shows that during calendar year 2006, monthly congestion charges ranged from a maximum of $376 million in August 2006 to a minimum of $41 million in October 2006.

Table 7-4 Monthly PJM congestion revenue statistics [Dollars (millions)]: Calendar years 2005 to 2006

	Maximum	Mean	Median	Minimum	Range
2005	$334	$174	$161	$57	$277
2006	$376	$134	$92	$41	$335

Approximately 28 percent of all calendar year 2006 congestion occurred in the high-demand months of July and January.

Hedged Congestion

Table 7-5 lists FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies. PJM is currently in a 12-month planning period that began on June 1, 2006, and will end on May 31, 2007.

Table 7-5 Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period

		FTR Revenues	FTR Target Allocations	FTR Credits	FTR Payout	Credits Deficiency	Credits Excess
Plannig Year 2005 to 2006	Jun-05	$181	$187	$181	97%	$6	$0
	Jul-05	$320	$326	$320	98%	$6	$0
	Aug-05	$335	$336	$335	100%	$2	$0
	Sep-05	$227	$259	$227	87%	$33	$0
	Oct-05	$228	$280	$228	81%	$53	$0
	Nov-05	$110	$143	$110	77%	$33	$0
	Dec-05	$284	$315	$284	90%	$31	$0
	Jan-06	$160	$150	$150	100%	$0	$10
	Feb-06	$159	$171	$159	93%	$12	$0
	Mar-06	$94	$127	$94	74%	$33	$0
	Apr-06	$51	$65	$51	78%	$14	$0
	May-06	$72	$76	$72	94%	$4	$0
	Total	$2,219	$2,436	$2,219	91%	$217	$0
	Values After Excess Revenues Distributed						
		$2,219	$2,436	$2,219	91%	$217	$0
Planning Year 2006 to 2007 (through December 31, 2006)	Jun-06	$168	$168	$168	100%	$0	$0
	Jul-06	$298	$294	$294	100%	$0	$5
	Aug-06	$374	$368	$368	100%	$0	$6
	Sep-06	$79	$75	$75	100%	$0	$4
	Oct-06	$47	$45	$45	100%	$0	$2
	Nov-06	$50	$44	$44	100%	$0	$6
	Dec-06	$101	$92	$92	100%	$0	$9
	Total	$1,117	$1,086	$1,086	100%	$0	$31

FTRs were paid at 91 percent of the target allocation level for the 12-month planning period that ended May 31, 2006. FTRs for the planning period ending May 31, 2007, have been paid at 100 percent of the target allocation level through December 31, 2006.

The total of ARR and FTR revenues hedged 99 percent of the congestion costs in the Day-Ahead and Balancing Energy Market within PJM for the 2005 to 2006 planning period and 98.4 percent of the congestion costs in PJM in the first seven months of the 2006 to 2007 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

LMP Differentials

LMP differentials were calculated for each PJM control zone, to provide an approximate indication of the geographic dispersion of congestion costs. LMP differentials for control zones are presented in Table 7-6 for calendar years 2005 and 2006 and were calculated as the difference between zonal LMP and the Western Hub LMP.

Table 7-6 shows overall congestion patterns in 2006. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the Bedington–Black Oak Interface, the Kammer and Wylie Ridge transformers and the 5004/5005 Interface. These constraints generally had the effect of increasing prices in eastern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

Table 7-6 Annual average zonal LMP differentials [Reference to Western Hub (Dollars per MWh)]: Calendar years 2005 to 2006

Control Zone	2005		2006	
	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$8.42	$7.07	$4.53	$4.42
AEP	($12.53)	($13.74)	($8.65)	($8.87)
AP	($2.38)	($2.89)	($2.72)	($2.41)
BGE	$6.36	$6.83	$5.46	$6.29
ComEd	($13.58)	($14.59)	($9.00)	($9.60)
DAY	($13.69)	($15.15)	($9.72)	($9.90)
DLCO	($15.33)	($17.42)	($11.08)	($11.78)
Dominion	$4.03	$5.11	$4.53	$5.32
DPL	$6.54	$4.54	$2.94	$1.98
JCPL	$5.26	$4.56	$1.18	$0.68
Met-Ed	$4.38	$3.15	$2.59	$1.55
PECO	$6.26	$4.34	$2.41	$1.29
PENELEC	($3.78)	($4.54)	($3.96)	($4.48)
PEPCO	$7.72	$8.01	$6.73	$7.73
PPL	$3.61	$1.96	$1.44	$0.40
PSEG	$8.04	$8.73	$3.64	$3.46
RECO	$5.78	$6.52	$3.58	$2.77

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constraint hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constraint hour. Constraints are often simultaneous, so the number of congestion-event hours exceeds the number of constraint hours and the number of congestion-event hours can exceed the number of hours in a year. In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. Prior state of the market reports measured real-time congestion frequency using the convention that a congestion-event hour exists if the particular facility is constrained for four or more of the 12 five-minute intervals comprising that hour. In 2006, there were 56,299 day-ahead, congestion-event hours, a slight increase from the 55,705 in 2005. In 2006, there were 19,510 real-time, congestion-event hours, a 19 percent decrease from 24,109 in 2005.

Congestion by Facility Type and Voltage

Both day-ahead and balancing congestion-event hours increased on the Midwest ISO flowgates in 2006. Day-ahead congestion-event hours increased on lines while real-time congestion-event hours decreased on lines. Both day-ahead and balancing congestion-event hours decreased on transformers and interfaces.

Day-ahead congestion costs decreased on all facility types in 2006 except unclassified.[15] Balancing congestion costs decreased on the Midwest ISO flowgates in 2006 and increased on all other facility types.

Table 7-7 provides congestion-event-hour subtotals and congestion cost subtotals comparing calendar year results by facility type: line, transformer, interface, flowgate and unclassified facilities.[16]

Total congestion costs associated with Midwest ISO flowgates decreased by $21.2 million, or 139 percent, from $15.2 million in 2005 to -$6.0 million in 2006. The Pierce and Rising flowgates together accounted for $0.8 million in congestion costs and were the largest contributors to positive congestion costs among Midwest ISO flowgates in 2006. The largest contribution to negative congestion costs among Midwest ISO flowgates came from the State Line–Wolf Lake flowgate with -$4.4 million in 2006 congestion costs.

Total congestion costs associated with interfaces decreased 25 percent from $1,023 million in 2005 to $764 million in 2006. Interfaces typically include multiple transmission facilities and reflect power flows into or through a wider geographic area. Interface congestion constituted 48 percent of total PJM congestion costs in 2006. Among interfaces, the Bedington–Black Oak and 5004/5005 Interfaces accounted for the

15 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.

16 The term "flowgate" refers to Midwest ISO flowgates in this context.

largest contribution to positive congestion costs in 2006. Bedington–Black Oak, with $492 million in congestion, had the highest congestion cost of any facility in PJM, accounting for 31 percent of the total PJM congestion costs in 2006. The Bedington–Black Oak and 5004/5005 Interfaces together accounted for $598 million or 37 percent of total PJM congestion costs in 2006. The largest contribution to negative congestion costs among interface constraints was the PL North Interface with -$0.06 million in 2006.[17]

Total congestion costs associated with lines decreased 2 percent from $504 million in 2005 to $496 million in 2006. Line congestion accounted for 31 percent of the total PJM congestion costs for 2006. The Cloverdale–Lexington, Kanawha–Matt Funk and Mount Storm–Pruntytown lines together accounted for $246 million or 50 percent of all line congestion costs and were the largest contributors to positive congestion among lines in 2006. The largest contribution to negative congestion among lines came from the Cedar Grove–Clifton line with -$6.36 million in 2006.

Total congestion costs associated with transformers decreased 38 percent from $538 million in 2005 to $335 million in 2006. Congestion on transformers accounted for 21 percent of the total PJM congestion costs in 2006. The Meadow Brook and Kammer transformers together accounted for $103 million or 31 percent of all transformer congestion costs and were the largest contributors to positive congestion costs among transformers in 2006. The largest contribution to negative congestion among transformers came from the Avon transformer in the AEP Control Zone with -$3.57 million in 2006.

Table 7-7 Congestion summary (By facility type): Calendar years 2005 to 2006

	2005				2006			
	Event Hours		Congestion Costs (Millions)		Event Hours		Congestion Costs (Millions)	
Type	Day Ahead	Real Time	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Balancing
Flowgate	824	359	$8.8	$6.4	1,350	859	$5.2	($11.2)
Interface	11,738	3,910	$1,073.3	($50.6)	8,273	2,792	$752.4	$11.6
Line	30,819	12,253	$636.3	($132.3)	34,558	11,447	$585.5	($89.6)
Transformer	12,324	7,587	$626.8	($88.4)	12,118	4,412	$349.2	($14.6)
Unclassified	NA	NA	$11.6	$0.0	NA	NA	$14.9	$0.0
Total	55,705	24,109	$2,356.8	($264.9)	56,299	19,510	$1,707.1	($103.8)

Table 7-8 shows congestion costs by facility voltage class. Congestion costs decreased across 500 kV, 230 kV, 138 kV and 115 kV class facilities in 2006. Congestion costs increased across 765 kV, 345 kV, 69 kV and 12 kV class facilities and unclassified facilities in 2006.

Congestion costs associated with 765 kV facilities increased 371 percent from $3.5 million in 2005 to the $16.7 million experienced in 2006. Congestion on 765 kV facilities comprised 1 percent of total 2006 PJM congestion costs. The Axton–Jacksons Ferry line accounted for $12.5 million or 75 percent of all 765 kV congestion costs and was the largest contributor to positive congestion among 765 kV facilities in 2006. There were no significant contributions to negative congestion from 765 kV facilities in 2006.

17 The PL North Interface congestion cost was not large enough to be in the top 25.

Congestion costs associated with 500 kV facilities decreased 24 percent from $1.349 billion in 2005 to $1.023 billion in 2006. Congestion on 500 kV facilities comprised 64 percent of total 2006 PJM congestion costs. The Bedington–Black Oak and 5004/5005 Interfaces together accounted for $598 million or 58 percent of all 500 kV congestion costs and were the largest contributors to positive congestion among 500 kV facilities in 2006. There were no significant contributions to negative congestion from 500 kV facilities in 2006.

Congestion costs associated with 230 kV facilities decreased 50 percent from $334 million in 2005 to $167 million in 2006. Congestion on 230 kV facilities comprised 10 percent of total 2006 PJM congestion costs. The Doubs and Whitpain transformers together accounted for $52 million or 31 percent of all 230 kV congestion costs and were the largest contributors to positive congestion among 230 kV facilities in 2006. The largest contribution to negative congestion among 230 kV facilities came from the Cedar Grove–Clifton line with -$6.36 million in 2006.

Congestion costs associated with 138 kV facilities decreased 15 percent from $214 million in 2005 to $182 million in 2006. Congestion on 138 kV facilities comprised 11 percent of total 2006 PJM congestion costs. The Meadow Brook and Bedington transformers together accounted for $98 million or 54 percent of all 138 kV congestion costs and were the largest contributors to positive congestion among 138 kV facilities in 2006. The largest contribution to negative congestion among 138 kV facilities came from the State Line–Wolf Lake line with -$4.4 million in 2006.

Table 7-8 Congestion summary (By facility voltage): Calendar years 2005 to 2006

	2005				2006			
	Event Hours		Congestion Costs (Millions)		Event Hours		Congestion Costs (Millions)	
Voltage (kV)	Day Ahead	Real Time	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Balancing
765	64	19	$3.4	$0.1	574	41	$16.9	($0.2)
500	15,881	7,668	$1,460.5	($111.6)	13,170	5,028	$1,007.5	$15.2
345	6,002	3,061	$177.2	($58.2)	5,949	2,481	$177.9	($44.7)
230	12,095	3,865	$390.1	($56.2)	10,249	3,367	$193.3	($26.6)
138	10,230	5,084	$236.6	($22.5)	15,713	5,102	$211.8	($30.1)
115	5,303	1,854	$50.3	($8.1)	4,486	1,344	$48.0	($11.9)
69	6,130	2,558	$27.1	($8.4)	6,129	2,147	$36.8	($5.4)
12	0	0	$0.0	$0.0	29	0	$0.0	$0.0
Unclassified	NA	NA	$11.6	$0.0	NA	NA	$14.9	$0.0
Total	55,705	24,109	$2,356.8	($264.9)	56,299	19,510	$1,707.1	($103.8)

Constraint Duration

Table 7-9 lists calendar year 2005 and 2006 constraints that affected more than 10 percent of PJM load or that were most frequently in effect and shows changes in congestion-event hours from 2005 to 2006.[18]

Constraints 1, 3, 5, 12, 20, 24 and 25 are the primary operating interfaces. For this group, the number of day-ahead-market, congestion-event hours decreased from 13,945 to 10,847 hours between 2005 and 2006. The number of real-time-market, congestion-event hours for the primary interfaces decreased from 6,166 to 4,175 hours between 2005 and 2006. The AP Control Zone facilities, items number 1, 3, 5 and 20, were constrained 10,724 hours in the Day-Ahead Market in 2005, compared to 8,843 hours in 2006. In the Real-Time Market, these AP Control Zone facilities were constrained for 5,581 hours in 2005 and 3,821 hours in 2006. The PJM Mid-Atlantic Region facilities, items number 12, 24 and 25, were constrained 3,221 hours in the Day-Ahead Market in 2005 compared to 2,004 hours in 2006. In the Real-Time Market, these PJM Mid-Atlantic facilities were constrained 585 hours in 2005 and 354 hours in 2006.

Table 7-9 Congestion-event summary: Calendar years 2005 to 2006

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2005	2006	Change	2005	2006	Change	2005	2006	Change	2005	2006	Change
1	Bedington - Black Oak	Interface	4,569	3,875	(694)	1,924	1,812	(112)	52%	44%	(8%)	22%	21%	(1%)
2	Cedar Grove - Roseland	Line	1,371	3,692	2,321	544	541	(3)	16%	42%	27%	6%	6%	(0%)
3	Wylie Ridge	Transformer	2,300	2,286	(14)	1,869	1,084	(785)	26%	26%	(0%)	21%	12%	(9%)
4	Laurel - Woodstown	Line	1,729	2,157	428	1,009	1,203	194	20%	25%	5%	11%	14%	2%
5	Kammer	Transformer	3,414	2,043	(1,371)	1,749	688	(1,061)	39%	23%	(16%)	20%	8%	(12%)
6	Kanawha - Matt Funk	Line	395	2,025	1,630	532	617	85	4%	23%	19%	6%	7%	1%
7	Cloverdale - Lexington	Line	1,107	1,517	410	679	961	282	13%	17%	5%	8%	11%	3%
8	5004/5005 Interface	Interface	1,906	1,738	(168)	782	341	(441)	22%	20%	(2%)	9%	4%	(5%)
9	Edison - Meadow Rd	Line	636	875	239	256	634	378	7%	10%	3%	3%	7%	4%
10	State Line - Wolf Lake	Flowgate	0	943	943	1	423	422	0%	11%	11%	0%	5%	5%
11	Mount Storm - Pruntytown	Line	379	891	512	986	465	(521)	4%	10%	6%	11%	5%	(6%)
12	West	Interface	589	981	392	370	328	(42)	7%	11%	4%	4%	4%	(0%)
13	Branchburg - Readington	Line	457	704	247	239	480	241	5%	8%	3%	3%	5%	3%
14	Bedington	Transformer	375	662	287	206	451	245	4%	8%	3%	2%	5%	3%
15	Bergen - Leonia	Line	1,026	948	(78)	51	52	1	12%	11%	(1%)	1%	1%	0%
16	Mitchell - Shepler Hill	Line	377	677	300	311	307	(4)	4%	8%	3%	4%	4%	(0%)
17	Elrama	Transformer	285	927	642	61	34	(27)	3%	11%	7%	1%	0%	(0%)
18	Calumet - River E.C.	Line	0	913	913	0	0	0	0%	10%	10%	0%	0%	0%
19	Elrama - Mitchell	Line	230	654	424	244	258	14	3%	7%	5%	3%	3%	0%
20	AP South	Interface	441	639	198	39	237	198	5%	7%	2%	0%	3%	2%
21	Carlls Corner - Sherman Ave	Line	133	712	579	9	160	151	2%	8%	7%	0%	2%	2%
22	Meadow Brook	Transformer	633	726	93	220	124	(96)	7%	8%	1%	3%	1%	(1%)
23	Bergen - Hoboken	Line	568	681	113	121	108	(13)	6%	8%	1%	1%	1%	(0%)
24	Central	Interface	1,261	699	(562)	67	15	(52)	14%	8%	(6%)	1%	0%	(1%)
25	East	Interface	1,371	324	(1,047)	148	11	(137)	16%	4%	(12%)	2%	0%	(2%)

18 Presented in order of descending sum of 2006 day-ahead and real-time congestion-event hours.

Constraint Costs

Table 7-10 presents the top constraints affecting positive congestion costs by facility for calendar years 2005 and 2006.[19] The Bedington–Black Oak Interface was the largest contributor to congestion costs in both 2005 and 2006 and with $492 million in total congestion costs, accounted for 31 percent of the total PJM congestion costs in 2006. The top four constraints in terms of congestion costs together comprised 49 percent of the total PJM congestion costs in 2006.

Table 7-10 Total annual PJM congestion costs (By facility): Calendar years 2005 to 2006

				Congestion Costs (Millions)						Percent of Total PJM Congestion Costs	
				2005			2006				
No.	Constraint	Type	Location	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total	2005	2006
1	Bedington - Black Oak	Interface	500	$607.3	($25.3)	$581.9	$486.1	$5.5	$491.6	28%	31%
2	5004/5005 Interface	Interface	500	$216.4	($17.7)	$198.7	$105.4	$0.6	$106.0	9%	7%
3	Mount Storm - Pruntytown	Line	AP	$50.4	($24.6)	$25.8	$100.3	($1.9)	$98.4	1%	6%
4	Kanawha - Matt Funk	Line	AEP	$41.1	($22.4)	$18.7	$101.9	($17.5)	$84.4	1%	5%
5	AP South	Interface	500	$57.1	($0.6)	$56.5	$76.2	$4.6	$80.8	3%	5%
6	Cloverdale - Lexington	Line	AEP	$36.2	($11.3)	$24.9	$64.8	($1.9)	$63.0	1%	4%
7	West	Interface	500	$45.7	($1.2)	$44.4	$55.5	$0.9	$56.4	2%	4%
8	Meadow Brook	Transformer	AP	$52.4	($2.0)	$50.4	$54.9	$0.4	$55.2	2%	3%
9	Kammer	Transformer	500	$147.7	($8.6)	$139.1	$41.7	$5.7	$47.4	7%	3%
10	Bedington	Transformer	AP	$16.7	($1.1)	$15.6	$45.7	($2.7)	$42.9	1%	3%
11	Doubs - Mount Storm	Line	500	$138.7	($13.1)	$125.6	$38.0	$0.5	$38.5	6%	2%
12	Doubs	Transformer	AP	$146.0	($0.3)	$145.7	$32.5	$0.3	$32.8	7%	2%
13	Axton	Transformer	AEP	$0.5	$0.0	$0.5	$23.8	($0.7)	$23.1	0%	1%
14	Whitpain	Transformer	PECO	$29.2	($1.7)	$27.4	$21.5	($2.4)	$19.1	1%	1%
15	Aqueduct - Doubs	Line	AP	$0.1	$0.0	$0.1	$18.4	$0.1	$18.5	0%	1%
16	Laurel - Woodstown	Line	AECO	$10.1	($1.1)	$9.0	$20.8	($3.7)	$17.2	0%	1%
17	Cedar Grove - Roseland	Line	PSEG	$15.7	($16.9)	($1.2)	$21.6	($5.4)	$16.2	0%	1%
18	Central	Interface	500	$44.8	($0.9)	$43.8	$15.8	($0.1)	$15.7	2%	1%
19	Unclassified	Unclassified	NA	$11.6	$0.0	$11.6	$14.9	$0.0	$14.9	1%	1%
20	East	Interface	500	$96.3	($1.8)	$94.5	$12.9	$0.2	$13.1	5%	1%
21	Wylie Ridge	Transformer	AP	$53.3	($37.7)	$15.6	$27.4	($14.3)	$13.1	1%	1%
22	Axton - Jacksons Ferry	Line	AEP	$2.1	($0.1)	$2.1	$12.7	($0.2)	$12.5	0%	1%
23	Dooms	Transformer	Dominion	$1.2	$0.2	$1.4	$12.4	($0.6)	$11.8	0%	1%
24	Cloverdale	Transformer	AEP	$7.3	$0.0	$7.3	$11.8	($0.3)	$11.5	0%	1%
25	Hunterstown	Transformer	Met-Ed	$4.8	$0.1	$4.9	$9.8	($0.2)	$9.5	0%	1%

19 Presented in descending order of 2006 total congestion costs.

Congestion-Event Summary for Midwest ISO Flowgates

Before the Phase 2 integration of ComEd began, PJM and the Midwest ISO had developed a JOA which defined a coordinated methodology for congestion management.[20] This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by both operators. A flowgate consists of one or more transmission elements intended to model MW flow and its impact on transmission limitations and transmission service usage.[21] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 7-11 shows the Midwest ISO flowgates which PJM took dispatch action to control during 2006 and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for Midwest ISO flowgates impacting PJM dispatch are presented by constraint, in descending order of the absolute value of total 2006 congestion costs. Among Midwest ISO flowgates in 2005, the Eau Claire–Arpin line constraint made the most significant contribution to negative congestion while the Crete–St. Johns Tap line made the most significant contribution to positive congestion. Among Midwest ISO flowgates in 2006, the State Line–Wolf Lake flowgate made the most significant contribution to negative congestion, while the Pierce and Rising flowgates made the most significant positive contributions.

Table 7-11 Top congestion cost impacts for Midwest ISO flowgates impacting PJM dispatch (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
State Line - Wolf Lake	Flowgate	Midwest ISO	$0.0	$0.0	$3.2	($7.6)	0	1	943	423
Lanesville	Flowgate	Midwest ISO	$0.0	$0.0	$0.6	($2.4)	0	0	43	99
Pierce	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.5	0	0	0	21
New London - Webster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	($0.4)	0	0	0	27
Rising	Flowgate	Midwest ISO	$0.0	$0.0	$0.3	$0.0	0	0	111	59
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.3	($0.3)	$0.3	($0.6)	23	67	51	81
Breed - West Casey	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	($0.1)	0	0	0	9
Crete - St Johns Tap	Flowgate	Midwest ISO	$8.6	$6.3	$0.1	$0.0	790	108	7	5
Bain - Kenosha	Flowgate	Midwest ISO	$0.0	$0.0	$0.1	($0.0)	0	0	92	26
Pana North	Flowgate	Midwest ISO	$0.0	$0.0	$0.6	($0.5)	0	0	103	79
State Line - Roxana	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	($0.0)	11	2	0	6
Powerton - Tazewell	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	0	0	0	2
Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	($0.0)	0	0	0	1
Gillespie Tap - Laclede Tap	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	($0.0)	0	0	0	5
Eau Claire - Arpin	Flowgate	Midwest ISO	$0.0	($0.4)	$0.0	$0.0	0	66	0	6

20 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 31, 2003) <http://www.pjm.com/documents/ downloads/agreements/joa-complete.pdf> (1,331 KB). The agreement is referred to here as the JOA.

21 See NERC Operating Manual, "Flowgate Administration Reference Document," Version 1 (March 21, 2002).

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 7-12 shows the 500 kV constraints with the largest impact on total congestion costs in PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints with the largest impact on total congestion costs in PJM are presented by constraint, in descending order of the absolute value of total 2006 congestion costs. In 2005, the Harrison–Harrison Tap and Belmont–Harrison line constraints contributed to negative congestion while the Kammer transformer, Bedington–Black Oak and 5004/5005 Interfaces contributed to positive congestion. In 2006, no 500 kV zone facilities contributed significantly to negative congestion. The Bedington–Black Oak Interface constraint was the largest 500 kV zone contributor to positive congestion in 2006. The AP South and 5004/5005 Interface constraints were also significant contributors to positive congestion in 2006.

Table 7-12 Regional constraints summary (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$607.3	($25.3)	$486.1	$5.5	4,569	1,924	3,875	1,812
5004/5005 Interface	Interface	500	$216.4	($17.7)	$105.4	$0.6	1,906	782	1,738	341
AP South	Interface	500	$57.1	($0.6)	$76.2	$4.6	441	39	639	237
West	Interface	500	$45.7	($1.2)	$55.5	$0.9	589	370	981	328
Kammer	Transformer	500	$147.7	($8.6)	$41.7	$5.7	3,414	1,749	2,043	688
Doubs - Mount Storm	Line	500	$138.7	($13.1)	$38.0	$0.5	548	545	240	50
Central	Interface	500	$44.8	($0.9)	$15.8	($0.1)	1,261	67	699	15
East	Interface	500	$96.3	($1.8)	$12.9	$0.2	1,371	148	324	11
Fort Martin - Pruntytown	Line	500	$14.7	($0.2)	$5.9	($0.0)	136	21	111	22
Harrison Tap - Kammer	Line	500	$0.1	($0.1)	$0.6	$0.2	1	14	51	52
Elroy - Hosensack	Line	500	$0.0	$0.3	$0.0	$0.0	0	40	0	4
Harrison - Harrison Tap	Line	500	$0.0	($0.1)	$0.0	$0.0	0	26	0	3
Alburtis - Branchburg	Line	500	$0.0	($0.0)	$0.0	$0.0	0	3	0	0
Belmont - Harrison	Line	500	$0.0	($0.3)	$0.0	$0.0	0	4	0	0
Branchburg - Elroy	Line	500	$0.3	($0.3)	$0.0	$0.0	10	8	0	0

Congestion on the Bedington-Black Oak and AP South Interfaces

The AP extra-high-voltage (EHV) system is the primary conduit for energy transfers from the AP and midwestern generating resources to southwestern PJM and eastern Virginia load and, to a lesser extent, to the central and eastern portion of the PJM Mid-Atlantic Region. Two AP interface constraints, Bedington–Black Oak and AP South, often restrict west-to-east energy transfers across the AP EHV system. Bedington–Black Oak was the largest contributor to congestion costs of any facility in PJM in calendar year 2006. In 2006, congestion costs associated with the Bedington–Black Oak and AP South Interface constraints were $492 million and $81 million, respectively. In 2006, Bedington–Black Oak and AP South were constrained 3,875 hours and 639 hours day ahead, respectively. Bedington–Black Oak and AP South were constrained 1,812 hours and 237 hours in real time in 2006, respectively. In 2005, congestion costs associated with Bedington-Black Oak and AP South were $582 million and $57 million, respectively. In 2005, Bedington–Black Oak and AP South were constrained 4,569 hours and 441 hours day ahead, respectively. Bedington–Black Oak and AP South were constrained 1,924 hours and 39 hours in real time in 2005, respectively. These results are summarized in Table 7-12.

Zonal Congestion

Summary

Day-ahead and balancing congestion costs within specific zones for calendar years 2005 to 2006 are presented in Table 7-13. The AP Control Zone, with $459.9 million, incurred the most congestion charges of any control zone in 2005. The leading contributors to congestion in the AP Control Zone in 2005 were the Bedington–Black Oak Interface and the Doubs transformer. These two facilities contributed $214.6 and $73.3 million in positive congestion costs, respectively, and together constituted 63 percent of all congestion charges in the AP Control Zone. The AEP Control Zone incurred the second highest amount of congestion charges in 2005, driven by congestion on the Kammer transformer and the Bedington–Black Oak Interface. These two facilities constituted $44.5 and $72 million in congestion charges, respectively, or 57 percent of the AEP Control Zone total.

In 2006, the AP and AEP Control Zones were once again the top two in terms of congestion charges. In the AP Control Zone, the Bedington–Black Oak Interface was again a leading contributor along with the Meadow Brook transformer. Together, these two facilities contributed a total of $208 million in congestion, or 61 percent of the AP Control Zone total. Congestion in the AEP Control Zone was driven by the Kanawha–Matt Funk line and the Bedington–Black Oak Interface. These two facilities contributed $104 million in congestion charges or 43 percent of the AEP Control Zone total.

Table 7-13 Congestion cost summary (By zone): Calendar years 2005 to 2006

	Congestion Costs (Millions)					
	2005			2006		
Control Zone	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
AECO	$70.4	$13.5	$83.8	$62.0	$5.3	$67.2
AEP	$351.2	($147.0)	$204.2	$302.1	($60.4)	$241.7
AP	$508.7	($48.9)	$459.9	$379.4	($39.3)	$340.1
BGE	$44.4	$52.8	$97.1	$64.3	$40.7	$105.0
ComEd	$60.5	$140.5	$201.0	$87.6	$61.3	$149.0
DAY	$31.5	($16.6)	$14.9	$21.8	($8.1)	$13.6
DLCO	$94.3	($50.9)	$43.4	$50.2	($21.8)	$28.4
Dominion	$236.1	($55.6)	$180.5	$259.4	($34.7)	$224.7
DPL	$109.3	$8.8	$118.1	$72.7	$14.5	$87.3
JCPL	$153.3	$9.2	$162.4	$94.8	$1.1	$95.9
Met-Ed	$38.4	($10.7)	$27.7	$27.3	($13.2)	$14.2
PECO	$33.5	($55.5)	($22.0)	($26.7)	($27.6)	($54.3)
PENELEC	$158.4	($3.7)	$154.7	$113.7	($10.3)	$103.4
PEPCO	$191.1	$1.6	$192.7	$155.3	$25.7	$181.0
PJM	$96.3	($61.3)	$34.9	($36.0)	($17.6)	($53.7)
PPL	($52.0)	($15.8)	($67.8)	($31.7)	($6.0)	($37.7)
PSEG	$212.7	($23.3)	$189.4	$99.4	($13.9)	$85.6
RECO	$18.8	($1.9)	$16.9	$11.5	$0.5	$12.0

Details of Regional and Zonal Congestion

Constraints were examined by zone and categorized by their effect on regions. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones. PJM is comprised of three regions composed of the PJM Mid-Atlantic Region with 11 control zones,[22] the PJM Western Region with five control zones (the AP, ComEd, AEP, DLCO and DAY Control Zones) and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table 7-14 through Table 7-30 present the top constraints affecting zonal congestion costs by control zone and demonstrate the influence of individual constraints on zonal congestion costs in calendar years 2005 and 2006. For each of these constraints, the zonal cost impacts are decomposed into their day-ahead and balancing market components. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top constraints affecting zonal congestion costs are presented by constraint, in descending order of the absolute value of total 2006 congestion costs. Both day-ahead and real-time,

22 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, PEPCO, PPL, PSEG and RECO Control Zones.

congestion-event hours are presented for each of the highlighted constraints. Constraints can have wide-ranging effects, influencing prices across multiple zones.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-14 shows the constraints with the largest impacts on total congestion cost in the AECO Control Zone. In 2005, the Cedar Grove–Roseland and Branchburg–Readington line constraints contributed to negative congestion while the Kammer transformer, Bedington–Black Oak and 5004/5005 Interfaces contributed to positive congestion. All of these constraints are located outside of the AECO Control Zone. In 2006, the Cedar Grove–Roseland and Branchburg–Readington line constraints again contributed significantly to negative congestion. The Laurel–Woodstown constraint increased significantly in both congestion costs and congestion-event hours and was the largest contributor to positive congestion in 2006 in the AECO Control Zone. As in 2005, in 2006 the Bedington–Black Oak and 5004/5005 Interface constraints resulted in large contributions to positive congestion costs.

Table 7-14 AECO Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Laurel - Woodstown	Line	AECO	$10.2	($1.1)	$20.9	($3.3)	1,729	1,009	2,157	1,203
Bedington - Black Oak	Interface	500	$12.0	$4.5	$11.3	$3.4	4,569	1,924	3,875	1,812
5004/5005 Interface	Interface	500	$8.6	$3.0	$6.1	$1.1	1,906	782	1,738	341
Cedar Grove - Roseland	Line	PSEG	($1.2)	($2.1)	($4.1)	($0.9)	1,371	544	3,692	541
Mount Storm - Pruntytown	Line	AP	$1.0	$1.6	$2.8	$0.5	379	986	891	465
West	Interface	500	$1.5	$1.4	$2.3	$0.9	589	370	981	328
Kammer	Transformer	500	$6.1	$3.6	$2.3	$0.7	3,414	1,749	2,043	688
Wylie Ridge	Transformer	AP	$2.9	$2.9	$1.9	$1.0	2,300	1,869	2,286	1,084
Branchburg - Readington	Line	PSEG	($0.4)	($0.9)	($1.4)	($1.4)	457	239	704	480
Cloverdale - Lexington	Line	AEP	$0.9	$0.6	$1.4	$1.1	1,107	679	1,517	961
Central	Interface	500	$3.4	$0.2	$2.3	$0.0	1,261	67	699	15
AP South	Interface	500	$0.9	$0.1	$1.5	$0.7	441	39	639	237
Kanawha - Matt Funk	Line	AEP	$0.3	$0.6	$1.3	$0.5	395	532	2,025	617
Deepwater	Transformer	AECO	$0.0	$0.0	$1.7	$0.1	0	0	66	67
Carlls Corner - Sherman Ave	Line	AECO	$0.3	$0.0	$1.8	($0.1)	133	9	712	160

BGE Control Zone

Table 7-15 shows the constraints with the largest impacts on total congestion cost in the BGE Control Zone. In 2005, the Cedar Grove–Roseland and Branchburg–Readington constraints contributed to negative congestion while the Bedington–Black Oak Interface and Doubs transformer constraints contributed significantly to positive congestion. In 2006, the Cedar Grove–Roseland and Branchburg–Readington constraints were again the largest contributors to negative congestion. The Bedington–Black Oak and AP South Interfaces along with the Mount Storm–Pruntytown lines were the largest contributors to positive congestion with the AP South Interface experiencing an increase in congestion-event hours as compared to 2005.

Table 7-15 BGE Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$15.2	$21.9	$24.3	$21.5	4,569	1,924	3,875	1,812
Mount Storm - Pruntytown	Line	AP	($0.2)	$7.6	$4.4	$2.4	379	986	891	465
AP South	Interface	500	($0.4)	$0.3	$3.3	$3.1	441	39	639	237
Aqueduct - Doubs	Line	AP	$0.0	$0.0	$5.9	$0.5	14	0	362	127
5004/5005 Interface	Interface	500	$7.7	$2.0	$5.2	$0.2	1,906	782	1,738	341
Doubs - Mount Storm	Line	500	$5.8	$8.6	$3.8	$1.3	548	545	240	50
West	Interface	500	$1.6	$1.8	$3.5	$1.1	589	370	981	328
Kammer	Transformer	500	$0.7	$7.5	$1.4	$3.0	3,414	1,749	2,043	688
Wylie Ridge	Transformer	AP	$2.3	$4.5	$1.3	$2.3	2,300	1,869	2,286	1,084
Cloverdale - Lexington	Line	AEP	($0.6)	$1.7	($0.7)	$4.2	1,107	679	1,517	961
Doubs	Transformer	AP	$12.3	$2.2	$3.1	$0.2	1,007	686	90	74
Cedar Grove - Roseland	Line	PSEG	$0.3	($2.9)	($2.3)	($0.8)	1,371	544	3,692	541
Conastone	Transformer	BGE	$0.0	$0.1	$2.5	$0.3	3	24	99	27
Branchburg - Readington	Line	PSEG	($0.3)	($1.9)	($0.4)	($2.1)	457	239	704	480
Kanawha - Matt Funk	Line	AEP	($0.2)	$2.7	($0.6)	$3.1	395	532	2,025	617

DPL Control Zone

Table 7-16 shows the constraints with the largest impacts on total congestion cost in the DPL Control Zone. In 2005, the Cedar Grove–Roseland and Branchburg–Readington line constraints contributed significantly to negative congestion while the Kammer transformer and the Bedington–Black Oak and 5004/5005 Interfaces contributed significantly to positive congestion. In 2006, the Cedar Grove–Roseland and Branchburg–Readington line constraints were again the top contributors to negative congestion. The Bedington–Black Oak and 5004/5005 Interfaces were the largest contributors to positive congestion in 2006.

Table 7-16 DPL Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$26.9	$1.6	$22.4	$6.5	4,569	1,924	3,875	1,812
5004/5005 Interface	Interface	500	$16.0	($0.3)	$10.0	$0.8	1,906	782	1,738	341
Cedar Grove - Roseland	Line	PSEG	($3.5)	($1.2)	($8.3)	($1.7)	1,371	544	3,692	541
Kammer	Transformer	500	$17.1	$3.7	$5.1	$1.9	3,414	1,749	2,043	688
Wylie Ridge	Transformer	AP	$8.9	$1.9	$3.8	$2.3	2,300	1,869	2,286	1,084
West	Interface	500	$4.2	$1.6	$4.4	$1.7	589	370	981	328
Mount Storm - Pruntytown	Line	AP	$2.1	$0.7	$5.4	$0.6	379	986	891	465
Cloverdale - Lexington	Line	AEP	$2.6	$0.6	$3.8	$1.9	1,107	679	1,517	961
Branchburg - Readington	Line	PSEG	($1.0)	($1.7)	($2.7)	($2.5)	457	239	704	480
Central	Interface	500	$8.3	($0.0)	$4.5	$0.0	1,261	67	699	15
Kanawha - Matt Funk	Line	AEP	$1.3	$0.3	$2.8	$1.1	395	532	2,025	617
AP South	Interface	500	$2.0	$0.0	$2.7	$1.1	441	39	639	237
Doubs - Mount Storm	Line	500	$5.7	($0.6)	$1.8	$0.5	548	545	240	50
Mardela - Vienna	Line	DPL	$0.0	($0.0)	$2.4	($0.3)	0	2	236	103
East	Interface	500	$11.2	($0.1)	$1.5	$0.1	1,371	148	324	11

JCPL Control Zone

Table 7-17 shows the constraints with the largest impacts on total congestion cost in the JCPL Control Zone. In 2006, as was the case in 2005, the Cedar Grove–Roseland and Branchburg–Readington lines, both PSEG Control Zone facilities, contributed significantly to negative congestion. In 2005, the Bedington–Black Oak and 5004/5005 Interfaces were the top contributors to positive congestion. In 2006, the Bedington–Black Oak Interface was the largest contributor to positive congestion costs followed by the 5004/5005 Interface.

Table 7-17 JCPL Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$34.1	$3.1	$31.0	$1.5	4,569	1,924	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	($10.8)	($4.4)	($29.9)	($0.9)	1,371	544	3,692	541
5004/5005 Interface	Interface	500	$29.2	$4.1	$19.2	$1.1	1,906	782	1,738	341
West	Interface	500	$7.3	$1.5	$10.4	$0.6	589	370	981	328
Kammer	Transformer	500	$24.0	$3.1	$9.3	$0.5	3,414	1,749	2,043	688
Wylie Ridge	Transformer	AP	$13.2	$2.9	$7.2	$0.8	2,300	1,869	2,286	1,084
Mount Storm - Pruntytown	Line	AP	$2.9	$0.9	$6.7	($0.0)	379	986	891	465
Central	Interface	500	$11.5	$0.2	$6.2	$0.0	1,261	67	699	15
Cloverdale - Lexington	Line	AEP	$2.9	$0.9	$5.3	$0.7	1,107	679	1,517	961
Kanawha - Matt Funk	Line	AEP	$2.1	$0.2	$5.4	$0.4	395	532	2,025	617
AP South	Interface	500	$2.7	$0.0	$4.1	$0.6	441	39	639	237
Unclassified	Unclassified	NA	$1.8	$0.0	$4.2	$0.0	NA	NA	NA	NA
Branchburg - Readington	Line	PSEG	$0.9	($2.1)	$0.2	($4.3)	457	239	704	480
Doubs - Mount Storm	Line	500	$7.8	$2.9	$2.6	($0.2)	548	545	240	50
East	Interface	500	$13.6	$0.3	$2.0	$0.0	1,371	148	324	11

Met-Ed Control Zone

Table 7-18 shows the constraints with the largest impacts on total congestion cost in the Met-Ed Control Zone. In 2005, the Doubs–Mount Storm and Mount Storm–Pruntytown constraints contributed to negative congestion while the Kammer transformer and 5004/5005 Interface constraints contributed significantly to positive congestion. In 2006, the AP South Interface, Cedar Grove–Roseland and Aqueduct–Doubs lines were the largest contributors to negative congestion. The Hunterstown and Jackson transformers, both Met-Ed Control Zone facilities, and the PJM West Interface were the largest contributors to positive congestion.

Table 7-18 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Hunterstown	Transformer	Met-Ed	$3.1	$0.0	$6.8	($0.2)	125	53	303	66
Jackson	Transformer	Met-Ed	$0.7	$0.0	$4.1	($0.0)	29	56	117	54
West	Interface	500	$2.0	($0.7)	$2.3	($0.2)	589	370	981	328
5004/5005 Interface	Interface	500	$8.7	($2.6)	$2.8	($1.1)	1,906	782	1,738	341
Gardners - Hunterstown	Line	Met-Ed	$0.0	($0.1)	$1.7	($0.7)	6	54	496	257
AP South	Interface	500	$0.9	($0.1)	$0.4	($1.4)	441	39	639	237
Kammer	Transformer	500	$6.5	($1.5)	$1.8	($0.8)	3,414	1,749	2,043	688
Cedar Grove - Roseland	Line	PSEG	($1.1)	$1.9	($1.6)	$0.8	1,371	544	3,692	541
Aqueduct - Doubs	Line	AP	($0.0)	$0.0	($0.6)	($0.2)	14	0	362	127
Middletown Jct	Transformer	Met-Ed	$0.0	$0.0	$0.9	($0.0)	0	15	25	16
Cloverdale - Lexington	Line	AEP	$0.4	($0.2)	$0.6	($1.4)	1,107	679	1,517	961
Mount Storm - Pruntytown	Line	AP	$0.5	($2.2)	$0.3	($1.1)	379	986	891	465
Middletown Jct - S Lebanon	Line	Met-Ed	$0.0	$0.0	$0.7	$0.0	0	0	15	0
Doubs - Mount Storm	Line	500	$1.4	($4.1)	($0.2)	($0.5)	548	545	240	50
Brunner Island - Yorkana	Line	Met-Ed	$0.0	$0.0	$0.4	$0.2	0	6	19	34

PECO Control Zone

Table 7-19 shows the constraints with the largest impacts on total congestion cost in the PECO Control Zone. In 2005, the Bedington–Black Oak and 5004/5005 Interface constraints along with the Kammer transformer contributed significantly to negative congestion while the Whitpain transformer and PJM East Interface constraints contributed to positive congestion. In 2006, the Bedington–Black Oak and 5004/5005 Interface constraints contributed significantly to negative congestion. The Whitpain transformer and Cedar Grove–Roseland line constraints were the most significant contributors to positive congestion in 2006.

Table 7-19 PECO Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($12.5)	($13.8)	($22.1)	($11.2)	4,569	1,924	3,875	1,812
Whitpain	Transformer	PECO	$20.9	($2.1)	$16.5	($2.7)	202	81	193	125
5004/5005 Interface	Interface	500	($4.0)	($8.1)	($7.4)	($2.2)	1,906	782	1,738	341
Cedar Grove - Roseland	Line	PSEG	$0.4	$4.5	$3.8	$2.6	1,371	544	3,692	541
AP South	Interface	500	($1.2)	($0.2)	($4.0)	($2.4)	441	39	639	237
West	Interface	500	($3.6)	($2.4)	($4.3)	($1.9)	589	370	981	328
Kammer	Transformer	500	($8.9)	($8.7)	($4.4)	($1.7)	3,414	1,749	2,043	688
Wylie Ridge	Transformer	AP	($1.7)	($6.6)	($3.6)	($2.1)	2,300	1,869	2,286	1,084
Mount Storm - Pruntytown	Line	AP	($0.2)	($5.0)	($3.0)	($1.7)	379	986	891	465
Kanawha - Matt Funk	Line	AEP	($0.4)	($1.0)	($2.7)	($1.5)	395	532	2,025	617
Branchburg - Readington	Line	PSEG	$0.7	$2.2	$1.9	$2.2	457	239	704	480
Central	Interface	500	($4.7)	($0.6)	($3.7)	($0.1)	1,261	67	699	15
East	Interface	500	$28.7	($0.6)	$3.7	$0.0	1,371	148	324	11
Cloverdale - Lexington	Line	AEP	($0.7)	($1.6)	$0.2	($3.0)	1,107	679	1,517	961
Doubs - Mount Storm	Line	500	($4.0)	($8.0)	($1.8)	($0.7)	548	545	240	50

PENELEC Control Zone

Table 7-20 shows the constraints with the largest impacts on total congestion cost in the PENELEC Control Zone. In 2005, the Kammer and Wylie Ridge transformer constraints contributed significantly to negative congestion while the Bedington–Black Oak and 5004/5005 Interfaces contributed to positive congestion. In 2006, the Kammer and Wylie Ridge transformer constraints were again the top contributors to negative congestion. The Cedar Grove–Roseland constraint increased significantly in both congestion costs and congestion-event hours and was the third largest contributor to positive congestion in 2006 in the PENELEC Control Zone. As in 2005, 2006 saw the largest contribution to positive congestion cost from the 5004/5005 Interface followed by the Bedington–Black Oak Interface constraint.

Table 7-20 PENELEC Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
5004/5005 Interface	Interface	500	$79.3	($3.5)	$45.9	($0.8)	1,906	782	1,738	341
Bedington - Black Oak	Interface	500	$30.2	$1.0	$24.2	($0.3)	4,569	1,924	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	$6.9	$0.7	$20.8	($0.1)	1,371	544	3,692	541
Wylie Ridge	Transformer	AP	($37.8)	$0.7	($17.9)	($1.4)	2,300	1,869	2,286	1,084
West	Interface	500	$13.8	($0.4)	$18.1	($0.4)	589	370	981	328
Kammer	Transformer	500	($45.0)	($1.0)	($15.7)	($0.2)	3,414	1,749	2,043	688
Central	Interface	500	$19.1	($0.1)	$8.9	($0.0)	1,261	67	699	15
Branchburg - Readington	Line	PSEG	$2.2	($0.0)	$6.8	$0.5	457	239	704	480
Seward	Transformer	PENELEC	$4.7	$0.1	$6.0	($0.1)	308	9	258	11
Kanawha - Matt Funk	Line	AEP	($1.3)	($0.3)	($4.4)	($0.8)	395	532	2,025	617
Mount Storm - Pruntytown	Line	AP	$1.8	$0.0	$4.7	($0.1)	379	986	891	465
Goudey - Laurel Lake	Line	PENELEC	$0.0	$0.0	$0.0	($4.4)	0	8	13	53
Cloverdale - Lexington	Line	AEP	($2.6)	$0.1	($3.9)	$0.2	1,107	679	1,517	961
Bedington	Transformer	AP	$0.9	$0.0	$2.6	$0.2	375	206	662	451
Altoona - Johnstown	Line	PENELEC	$3.3	$0.2	$2.5	($0.1)	178	15	107	8

PEPCO Control Zone

Table 7-21 shows the constraints with the largest impacts on total congestion cost in the PEPCO Control Zone. In 2005, the Cedar Grove–Roseland and Branchburg–Readington line constraints contributed significantly to negative congestion while the Bedington–Black Oak Interface and Kammer transformer constraints contributed to positive congestion. In 2006, the Cedar Grove–Roseland line was the largest contributor to negative congestion followed by the Branchburg–Readington line. The Bedington–Black Oak Interface and Mount Storm–Pruntytown constraints were the largest contributors to positive congestion in 2006 in the PEPCO Control Zone.

Table 7-21 PEPCO Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$86.3	$0.2	$72.2	$13.5	4,569	1,924	3,875	1,812
Mount Storm - Pruntytown	Line	AP	$7.4	($0.6)	$15.4	$1.0	379	986	891	465
AP South	Interface	500	$6.7	$0.1	$10.8	$2.7	441	39	639	237
Cloverdale - Lexington	Line	AEP	$8.6	($1.8)	$7.4	$4.0	1,107	679	1,517	961
Cedar Grove - Roseland	Line	PSEG	($4.4)	$1.5	($10.0)	($0.6)	1,371	544	3,692	541
Aqueduct - Doubs	Line	AP	$0.1	$0.0	$10.6	($0.4)	14	0	362	127
Kammer	Transformer	500	$33.3	$0.3	$8.0	$1.8	3,414	1,749	2,043	688
Kanawha - Matt Funk	Line	AEP	$3.3	($0.4)	$7.9	$1.4	395	532	2,025	617
Doubs - Mount Storm	Line	500	$12.1	$1.7	$4.6	$1.4	548	545	240	50
Doubs	Transformer	AP	$20.2	$1.2	$5.9	($0.1)	1,007	686	90	74
Wylie Ridge	Transformer	AP	$12.2	($0.3)	$4.2	$0.8	2,300	1,869	2,286	1,084
West	Interface	500	$4.0	$0.2	$3.4	$0.2	589	370	981	328
Bedington	Transformer	AP	$0.3	$0.2	$3.3	$0.2	375	206	662	451
Dickerson - Doubs	Line	PEPCO	$0.0	$0.0	$3.3	$0.1	0	0	116	11
Branchburg - Readington	Line	PSEG	($0.9)	($0.6)	($2.8)	($0.6)	457	239	704	480

PPL Control Zone

Table 7-22 shows the constraints with the largest impacts on total congestion cost in the PPL Control Zone. In 2005, the Kammer transformer and 5004/5004 Interface constraints contributed significantly to negative congestion while the PJM East Interface and Cedar Grove–Roseland constraints contributed to positive congestion. In 2006, the Bedington–Black Oak and 5004/5005 Interface constraints were the greatest contributors to negative congestion. The Cedar Grove–Roseland constraint increased in both congestion costs and congestion-event hours and was the largest contributor to positive congestion in 2006 in the PPL Control Zone.

Table 7-22 PPL Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
5004/5005 Interface	Interface	500	($27.5)	($3.7)	($13.2)	($1.0)	1,906	782	1,738	341
Bedington - Black Oak	Interface	500	($11.8)	($3.5)	($7.2)	($1.2)	4,569	1,924	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	$4.3	$0.1	$7.6	($0.0)	1,371	544	3,692	541
West	Interface	500	($3.8)	($0.6)	($4.5)	$0.2	589	370	981	328
Central	Interface	500	($9.4)	($0.3)	($4.2)	($0.0)	1,261	67	699	15
Wylie Ridge	Transformer	AP	($8.5)	($1.8)	($2.8)	($0.6)	2,300	1,869	2,286	1,084
Cloverdale - Lexington	Line	AEP	($1.4)	$0.2	($3.5)	$0.2	1,107	679	1,517	961
Kanawha - Matt Funk	Line	AEP	($1.1)	($0.1)	($2.4)	($0.8)	395	532	2,025	617
Kammer	Transformer	500	($14.1)	($1.7)	($2.6)	($0.2)	3,414	1,749	2,043	688
Mount Storm - Pruntytown	Line	AP	($1.3)	($1.7)	($2.5)	($0.4)	379	986	891	465
AP South	Interface	500	($1.0)	($0.0)	($1.2)	($0.6)	441	39	639	237
East	Interface	500	$10.2	($0.7)	$1.6	($0.0)	1,371	148	324	11
Branchburg - Readington	Line	PSEG	$0.7	($0.5)	$2.2	($0.9)	457	239	704	480
Doubs - Mount Storm	Line	500	($3.7)	($1.9)	($1.0)	($0.1)	548	545	240	50
Conastone	Transformer	BGE	$0.0	$0.1	$0.6	$0.3	3	24	99	27

PSEG Control Zone

Table 7-23 shows the constraints with the largest impacts on total congestion cost in the PSEG Control Zone. In 2005, no facilities significantly contributed to negative congestion in the PSEG Control Zone. In 2005, the Cedar Grove–Clifton line, a PSEG Control Zone facility, and the 5004/5005 Interface constraints were the largest contributors to positive congestion. In 2006, the Cedar Grove–Clifton line made the most significant contribution to negative congestion and incurred significantly fewer congestion-event hours as compared to 2005. In 2006, the Cedar Grove–Roseland and 5004/5005 Interface constraints were the top contributors to positive congestion.

Table 7-23 PSEG Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Cedar Grove - Roseland	Line	PSEG	$13.3	($4.8)	$28.5	($2.7)	1,371	544	3,692	541
5004/5005 Interface	Interface	500	$21.7	$1.7	$8.1	$1.6	1,906	782	1,738	341
Edison - Meadow Rd	Line	PSEG	$5.2	($0.0)	$9.0	($0.5)	636	256	875	634
Branchburg - Readington	Line	PSEG	$4.6	($0.7)	$10.0	($2.2)	457	239	704	480
Bergen - Hoboken	Line	PSEG	$8.6	($0.2)	$4.8	($0.1)	568	121	681	108
Cedar Grove - Clifton	Line	PSEG	$33.9	($0.9)	$1.3	($5.2)	2,880	266	168	536
Brunswick - Edison	Line	PSEG	$1.6	($0.0)	$3.3	($0.1)	174	89	464	206
Bergen - Leonia	Line	PSEG	$3.5	$0.3	$2.4	($0.0)	1,026	51	948	52
Whitpain	Transformer	PECO	$0.3	($0.1)	$1.8	$0.4	202	81	193	125
AP South	Interface	500	$1.4	($0.1)	$0.9	$1.2	441	39	639	237
Wylie Ridge	Transformer	AP	$7.5	($0.6)	$2.7	($0.8)	2,300	1,869	2,286	1,084
South Mahwah - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	($1.6)	0	19	0	37
Bedington - Black Oak	Interface	500	$9.9	$0.2	$0.6	$0.8	4,569	1,924	3,875	1,812
Unclassified	Unclassified	NA	$4.0	$0.0	$1.4	$0.0	NA	NA	NA	NA
Bayway - Doremus	Line	PSEG	$0.0	$0.0	$1.4	$0.0	2	0	418	2

RECO Control Zone

Table 7-24 shows the constraints with the largest impacts on total congestion cost in the RECO Control Zone. In 2005, no facilities significantly contributed to negative congestion in the RECO Control Zone. In 2005, the Bedington–Black Oak and 5004/5005 Interface constraints were the largest contributors to positive congestion. In 2006, no facilities significantly contributed to negative congestion in the RECO Control Zone. In 2006, the Bedington–Black Oak Interface and the Cedar Grove–Roseland line were the top contributors to positive congestion.

Table 7-24 RECO Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$3.4	($0.1)	$2.3	$0.1	4,569	1,924	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	$0.8	($0.7)	$1.7	($0.0)	1,371	544	3,692	541
5004/5005 Interface	Interface	500	$3.1	$0.0	$1.4	$0.2	1,906	782	1,738	341
West	Interface	500	$0.6	($0.1)	$0.7	$0.0	589	370	981	328
Kammer	Transformer	500	$2.3	($0.1)	$0.6	$0.0	3,414	1,749	2,043	688
Mount Storm - Pruntytown	Line	AP	$0.3	($0.2)	$0.6	($0.0)	379	986	891	465
AP South	Interface	500	$0.3	($0.0)	$0.4	$0.2	441	39	639	237
Central	Interface	500	$1.2	$0.0	$0.5	$0.0	1,261	67	699	15
Wylie Ridge	Transformer	AP	$1.2	($0.2)	$0.5	($0.0)	2,300	1,869	2,286	1,084
Branchburg - Readington	Line	PSEG	$0.2	($0.1)	$0.5	($0.1)	457	239	704	480
Kanawha - Matt Funk	Line	AEP	$0.1	($0.0)	$0.4	($0.0)	395	532	2,025	617
Cloverdale - Lexington	Line	AEP	$0.3	($0.1)	$0.3	($0.0)	1,107	679	1,517	961
Doubs - Mount Storm	Line	500	$0.8	($0.1)	$0.2	$0.0	548	545	240	50
Aqueduct - Doubs	Line	AP	$0.0	$0.0	$0.1	$0.0	14	0	362	127
Axton	Transformer	AEP	$0.0	$0.0	$0.1	($0.0)	16	0	218	35

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-25 shows the constraints with the largest impacts on total congestion cost in the AEP Control Zone. The largest contributions to negative congestion in 2005 came from the Cedar Grove–Roseland and Cloverdale–Lexington constraints. In 2005, the Kammer transformer and the Bedington–Black Oak Interface constraints were the largest contributors to positive congestion. The largest contribution to negative congestion in 2006 came from the Cloverdale–Lexington constraint. In 2006, as was the case in 2005, the Bedington–Black Oak Interface constraint was the largest contributor to positive congestion costs. The Kanawha–Matt Funk constraint increased significantly in both congestion cost and congestion-event hours and was the second largest contributor to positive congestion costs in 2006.

Table 7-25 AEP Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$87.6	($15.5)	$69.9	($12.9)	4,569	1,924	3,875	1,812
Kanawha - Matt Funk	Line	AEP	$19.1	($12.7)	$58.4	($11.5)	395	532	2,025	617
Kammer	Transformer	500	$72.6	($28.1)	$28.4	($3.6)	3,414	1,749	2,043	688
Axton	Transformer	AEP	$0.3	$0.0	$20.0	($0.5)	16	0	218	35
Mount Storm - Pruntytown	Line	AP	$9.3	($6.8)	$18.4	($1.8)	379	986	891	465
5004/5005 Interface	Interface	500	$18.4	($4.9)	$12.5	$0.1	1,906	782	1,738	341
Axton - Jacksons Ferry	Line	AEP	$1.2	($0.1)	$8.8	($0.1)	30	10	380	10
Cedar Grove - Roseland	Line	PSEG	$2.0	($11.1)	$8.8	($0.6)	1,371	544	3,692	541
Wylie Ridge	Transformer	AP	$18.7	($23.4)	$14.1	($6.6)	2,300	1,869	2,286	1,084
Cloverdale - Lexington	Line	AEP	($4.2)	($4.6)	($3.0)	($2.6)	1,107	679	1,517	961
Central	Interface	500	$5.3	($0.5)	$4.9	$0.0	1,261	67	699	15
AP South	Interface	500	$3.4	($0.4)	$5.3	($1.2)	441	39	639	237
Bedington	Transformer	AP	$0.8	($0.3)	$4.3	($0.6)	375	206	662	451
Breed - Wheatland	Line	AEP	$7.3	$0.0	$3.8	($0.3)	218	7	411	29
West	Interface	500	$2.9	($3.1)	$5.9	($2.5)	589	370	981	328

AP Control Zone

Table 7-26 shows the constraints with the largest impacts on total congestion cost in the AP Control Zone. In 2005, the Kammer and Wylie Ridge transformers contributed significantly to negative congestion while the Bedington–Black Oak Interface and Doubs transformer contributed to positive congestion. In 2006, the Kammer transformer was again the top contributor to negative congestion followed by the Aqueduct–Doubs constraint. The Bedington–Black Oak Interface and Meadow Brook transformer constraints were the top contributors to positive congestion in 2006.

Table 7-26 AP Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$218.6	($3.9)	$177.8	($9.4)	4,569	1,924	3,875	1,812
Meadow Brook	Transformer	AP	$35.5	($0.4)	$38.9	$0.5	633	220	726	124
Mount Storm - Pruntytown	Line	AP	$18.0	($2.9)	$39.2	$0.1	379	986	891	465
Bedington	Transformer	AP	$12.9	($0.6)	$30.8	($3.1)	375	206	662	451
AP South	Interface	500	$14.7	($0.1)	$21.5	($1.6)	441	39	639	237
Doubs	Transformer	AP	$75.3	($2.0)	$14.0	$0.2	1,007	686	90	74
Kammer	Transformer	500	($19.3)	($0.0)	($12.1)	($0.7)	3,414	1,749	2,043	688
Cloverdale - Lexington	Line	AEP	$11.8	($1.2)	$14.1	($3.9)	1,107	679	1,517	961
Aqueduct - Doubs	Line	AP	($0.0)	$0.0	($9.8)	($0.0)	14	0	362	127
Kanawha - Matt Funk	Line	AEP	$6.5	($0.8)	$9.7	($1.4)	395	532	2,025	617
Doubs - Mount Storm	Line	500	$34.4	($7.6)	$8.0	($1.0)	548	545	240	50
Wylie Ridge	Transformer	AP	($1.6)	($9.3)	($0.6)	($6.3)	2,300	1,869	2,286	1,084
Cedar Grove - Roseland	Line	PSEG	$4.9	($0.4)	$5.6	$0.2	1,371	544	3,692	541
Branchburg - Readington	Line	PSEG	$0.2	($1.7)	$1.1	($4.7)	457	239	704	480
Fort Martin - Pruntytown	Line	500	$7.7	($0.0)	$3.4	($0.3)	136	21	111	22

ComEd Control Zone

Table 7-27 shows the constraints with the largest impacts on total congestion cost in the ComEd Control Zone. In 2005, no facilities significantly contributed to negative congestion in the ComEd Control Zone. In 2005, the Kammer and Wylie Ridge transformer constraints were the largest contributors to positive congestion. The only significant contribution to negative congestion in 2006 came from the Northwest–Devon line, a ComEd Control Zone facility. In 2006, the Kammer transformer and the Cloverdale–Lexington line constraints were the top contributors to positive congestion.

Table 7-27 ComEd Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Kammer	Transformer	500	$15.0	$33.5	$5.8	$9.6	3,414	1,749	2,043	688
Cloverdale - Lexington	Line	AEP	$1.7	$4.0	$6.5	$7.0	1,107	679	1,517	961
Wylie Ridge	Transformer	AP	$4.8	$17.4	$4.2	$8.6	2,300	1,869	2,286	1,084
Bedington - Black Oak	Interface	500	$0.5	$8.2	$3.9	$8.5	4,569	1,924	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	$2.5	$9.1	$6.9	$2.4	1,371	544	3,692	541
Branchburg - Readington	Line	PSEG	$0.4	$4.2	$0.7	$6.8	457	239	704	480
Kanawha - Matt Funk	Line	AEP	$0.9	$2.9	$1.6	$5.5	395	532	2,025	617
Cherry Valley - Belvidere	Line	ComEd	$1.1	$0.1	$6.4	($0.2)	30	14	39	12
5004/5005 Interface	Interface	500	$1.7	$7.2	$4.6	$0.8	1,906	782	1,738	341
Jefferson - Taylor	Line	ComEd	$0.0	$0.0	$4.6	$0.6	2	0	137	11
Dresden	Transformer	ComEd	$0.0	($0.0)	$4.7	$0.3	0	93	64	18
West	Interface	500	$1.5	$4.6	$0.9	$4.0	589	370	981	328
Oak Park - Ridgeland	Line	ComEd	$0.0	$0.0	$4.1	$0.0	5	0	338	0
AP South	Interface	500	$0.7	$0.4	$1.6	$2.1	441	39	639	237
Northwest - Devon	Line	ComEd	$0.0	($0.1)	$0.2	($3.4)	0	8	17	52

DAY Control Zone

Table 7-28 shows the constraints with the largest impacts on total congestion cost in the DAY Control Zone. Negative contributions to congestion in 2005 came from the Doubs–Mount Storm line and the Avon transformer constraints. In 2005, the Kammer transformer and the 5004/5005 Interface constraints were the largest contributors to positive congestion. Neither of these facilities is located in the DAY Control Zone. The Avon transformer increased in congestion frequency in 2006 as compared to 2005 and was the largest contributor to negative congestion in 2006. In 2006, the Kammer transformer constraint was the top contributor to positive congestion costs followed by the Cedar Grove–Roseland and Cloverdale–Lexington line constraints.

Table 7-28 DAY Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Kammer	Transformer	500	$9.0	($4.3)	$3.2	($0.6)	3,414	1,749	2,043	688
Cedar Grove - Roseland	Line	PSEG	$1.2	($1.2)	$2.5	($0.3)	1,371	544	3,692	541
Cloverdale - Lexington	Line	AEP	$0.8	($0.5)	$2.1	($0.0)	1,107	679	1,517	961
5004/5005 Interface	Interface	500	$3.4	($0.8)	$2.5	($0.5)	1,906	782	1,738	341
Avon	Transformer	AEP	$0.0	($0.4)	$0.0	($1.4)	0	110	0	229
Kanawha - Matt Funk	Line	AEP	$0.7	($0.7)	$1.8	($0.7)	395	532	2,025	617
West	Interface	500	$1.7	($0.3)	$1.4	($0.5)	589	370	981	328
Marquis - Killen	Line	AEP	$0.0	$0.0	$0.9	$0.0	0	0	288	0
Central	Interface	500	$1.8	$0.0	$0.8	($0.0)	1,261	67	699	15
Meadow Brook	Transformer	AP	$0.0	($0.0)	$0.4	($0.0)	633	220	726	124
Doubs - Mount Storm	Line	500	$0.6	($0.8)	$0.4	$0.0	548	545	240	50
Cloverdale	Transformer	AEP	$0.2	$0.0	$0.3	$0.0	192	0	221	34
East	Interface	500	$1.1	($0.1)	$0.3	($0.0)	1,371	148	324	11
AP South	Interface	500	$0.7	($0.1)	$0.5	($0.2)	441	39	639	237
Axton	Transformer	AEP	$0.0	$0.0	$0.3	($0.1)	16	0	218	35

DLCO Control Zone

Table 7-29 shows the constraints with the largest impacts on total congestion cost in the DLCO Control Zone. Negative contributions to congestion in 2005 came from two AP Control Zone facilities, the Elrama–Mitchell and Mount Storm–Pruntytown lines. In 2005, the Bedington–Black Oak Interface and Wylie Ridge transformer constraints were the largest contributors to positive congestion. Neither of these facilities is located in the DLCO Control Zone. In 2006, the Elrama–Mitchell line was again a significant contributor to negative congestion along with the Sammis–Wylie Ridge line. The Bedington–Black Oak Interface, Cedar Grove–Roseland line and Wylie Ridge transformer constraints were the most significant contributors to positive congestion in 2006.

Table 7-29 DLCO Control Zone top congestion cost impacts (By facility): Calendar years 2005 to 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$15.5	($6.7)	$10.3	($5.1)	4,569	1,924	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	$2.6	($3.6)	$5.0	($0.9)	1,371	544	3,692	541
Wylie Ridge	Transformer	AP	$18.3	($10.2)	$8.4	($4.9)	2,300	1,869	2,286	1,084
5004/5005 Interface	Interface	500	$10.8	($4.1)	$3.5	($0.5)	1,906	782	1,738	341
West	Interface	500	$3.3	($1.4)	$3.4	($0.9)	589	370	981	328
Mount Storm - Pruntytown	Line	AP	$1.6	($3.2)	$2.5	($0.7)	379	986	891	465
Kammer	Transformer	500	$5.6	($0.7)	$1.8	($0.3)	3,414	1,749	2,043	688
Sammis - Wylie Ridge	Line	AP	($0.1)	($0.4)	$0.0	($1.3)	5	67	0	125
Cheswick - Evergreen	Line	DLCO	$0.0	$0.0	$1.2	($0.0)	0	1	167	45
Crescent	Transformer	DLCO	$0.0	$0.1	$0.0	$0.9	0	22	0	23
Central	Interface	500	$4.0	($0.2)	$0.9	($0.0)	1,261	67	699	15
Elrama	Transformer	AP	$0.5	($0.0)	$0.9	($0.0)	285	61	927	34
Kanawha - Matt Funk	Line	AEP	$0.6	($0.3)	$1.2	($0.4)	395	532	2,025	617
Elrama - Mitchell	Line	AP	$0.6	($2.5)	$1.2	($1.9)	230	244	654	258
Branchburg - Readington	Line	PSEG	$0.6	($1.1)	$1.7	($1.0)	457	239	704	480

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-30 shows the constraints with the largest impacts on total congestion cost in the Dominion Control Zone. In 2005, the Mount Storm–Pruntytown constraint contributed significantly to negative congestion while the Bedington–Black Oak Interface, Doubs–Mount Storm line and AP South Interface constraints contributed to positive congestion. In 2006, the Cedar Grove–Roseland constraint contributed significantly to negative congestion. The AP South Interface constraint increased in both congestion costs and congestion-event hours and was the second largest contributor to positive congestion in 2006 in the Dominion Control Zone. The largest contribution to positive congestion costs in 2006 in the Dominion Control Zone came from the Bedington–Black Oak Interface constraint.

Table 7-30 Dominion Control Zone top congestion cost impacts (By facility): Phase 5, 2005 to December 31, 2006

			Congestion Costs (Millions)				Event Hours			
			2005		2006		2005		2006	
Constraint	Type	Location	Day Ahead	Balancing	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$77.3	($15.0)	$70.4	($6.0)	4,569	1,924	3,875	1,812
AP South	Interface	500	$22.1	($0.4)	$28.0	$1.6	441	39	639	237
Cloverdale - Lexington	Line	AEP	$9.8	($6.7)	$35.3	($7.8)	1,107	679	1,517	961
Doubs - Mount Storm	Line	500	$54.1	($1.5)	$15.2	($0.4)	548	545	240	50
Cedar Grove - Roseland	Line	PSEG	($6.1)	$2.7	($11.5)	($1.5)	1,371	544	3,692	541
Meadow Brook	Transformer	AP	$13.7	($1.3)	$13.2	($0.2)	633	220	726	124
Kanawha - Matt Funk	Line	AEP	$6.7	($10.3)	$19.5	($9.8)	395	532	2,025	617
Aqueduct - Doubs	Line	AP	$0.0	$0.0	$9.2	$0.5	14	0	362	127
Dooms	Transformer	Dominion	$0.9	$0.3	$9.9	($0.6)	22	31	150	147
Doubs	Transformer	AP	$20.5	$1.0	$6.8	$0.1	1,007	686	90	74
5004/5005 Interface	Interface	500	$5.5	$1.1	$4.5	$0.9	1,906	782	1,738	341
Kammer	Transformer	500	$5.6	($3.6)	$8.1	($2.9)	3,414	1,749	2,043	688
Mount Storm - Pruntytown	Line	AP	$5.5	($13.6)	$6.5	($1.4)	379	986	891	465
Cloverdale	Transformer	AEP	$3.3	$0.0	$5.6	($0.5)	192	0	221	34
Dayton - Harrisonburg	Line	Dominion	$0.9	$0.0	$4.6	$0.0	27	0	74	0

Economic Planning Process

On September 8, 2006, PJM filed proposed changes to its RTEP Protocol.[23] PJM proposed modifications to the metrics used to determine whether transmission should be upgraded or expanded. On November 21, 2006, the United States Federal Energy Regulatory Commission (FERC) conditionally accepted PJM's proposal subject to PJM submitting a compliance filing within 120 days of its order.[24]

PJM's current planning process for economic transmission expansions is based on the concept of unhedgeable congestion.[25] In its September 8th filing, PJM proposed the replacement of the unhedgeable congestion metric for determining whether transmission should be upgraded or expanded with a set of congestion metrics including unhedgeable congestion. These metrics include: total production costs; total load payments; total generator revenue; zonal load payments; zonal FTR credits; total transmission system losses; and total capacity payments.[26] PJM will perform market simulations to compare the costs and benefits of the proposed transmission projects.

The metrics will be applied to evaluating all types of transmission projects, including whether to modify or accelerate reliability enhancements already in the RTEP that could also relieve one or more economic constraints and whether to propose new, economic transmission projects that could relieve one or more economic constraints. PJM will also evaluate whether demand response resources or new generation could eliminate the need for an economic upgrade. After PJM makes an evaluation, it will present its analysis to the stakeholders (Transmission Expansion Advisory Committee), which will, in turn, present its recommendations to the PJM Board.

The proposed economic planning revisions incorporate improvements over the existing process but require ongoing development. The most significant improvements are the inclusion of more appropriate analytical metrics, the consideration of forecasts and the evaluation of demand-side response and generation resources as competitive alternatives to transmission investment. The approach to weighting and evaluating the metrics in the context of actual transmission projects will require substantial effort. New transmission projects, and the lack of existing transmission, can have significant impacts on the PJM markets and the goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market-driven processes as much as is practicable.

23 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits modifications to its Regional Transmission Expansion Planning Protocol, Docket No. ER06-1474-000 (September 8, 2006).

24 117 FERC ¶ 61,218.

25 PJM divides transmission expansions into reliability and economic categories. Reliability expansions are those needed to ensure that load can be met reliably. Economic expansions (also called "market efficiency" expansions) are those that will reduce the costs of meeting load but are not needed to meet load reliably.

26 PJM defines "economic constraints" as including, but not limited to, constraints that cause: (i) significant historical gross congestion; (ii) significant historical unhedgeable congestion; (iii) proration of ARR requests; or (iv) significant congestion as forecast in the market efficiency analysis.

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give firm transmission customers an offset against congestion costs. An FTR provides holders revenues, or charges, equal to the difference in prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides holders revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that firm transmission customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs have been available to firm point-to-point and network service transmission customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998.[1] Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[2] Firm transmission customers can take allocated ARRs or the underlying FTRs through a process called self-scheduling.

Firm transmission customers have access to FTRs/ARRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission customers receive requested FTRs/ARRs to the extent that they are consistent both with the physical capability of the transmission system and with FTR/ARR requests of other eligible customers.

The *2006 State of the Market Report* focuses on two FTR/ARR planning periods: the 2005 to 2006 planning period which covers June 1, 2005, through May 31, 2006, and the 2006 to 2007 planning period which covers June 1, 2006, through May 31, 2007.[3]

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.[4]

1 PJM network and firm long-term point-to-point transmission service customers are referred to as eligible customers.

2 87 FERC ¶ 61,054 (1999).

3 Annual FTR accounting changed from calendar year to planning period beginning with the 2003 to 2004 planning period. Transition to this new accounting period required that 2003 calendar year accounting be extended by five months and encompass January 1, 2003, through May 31, 2004.

4 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."

Overview

Financial Transmission Rights (FTRs)

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. In addition to the Annual FTR Auction, PJM conducts regular monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability.[5] FTR products include FTR obligations and FTR options. Each of these is available for 24-hour, on-peak and off-peak periods. FTRs have terms varying from one month to one year. PJM submitted to the United States Federal Energy Regulatory Commission (FERC) revisions to the PJM Open Access Transmission Tariff (OATT) to include long-term ARRs and FTRs that would be in effect for 10 planning periods.[6] Long-term FTRs would be obtained by directly converting long-term ARRs into self-scheduled FTRs. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2006 to 2007 planning period include the Laurel–Woodstown line and the Bedington-Black Oak Interface. Prorating of FTRs is in direct proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

- **Demand.** There is no limit on FTR demand in any FTR auction. When a new control zone is integrated into PJM, the participants in that control zone must choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive years following their integration date. In the Annual FTR Auction for the 2006 to 2007 planning period, total demand was 1,608,422 MW, up from 871,841 MW during the 2005 to 2006 planning period. The Annual FTR Auction cleared 168,167 MW (10.5 percent of demand), leaving 1,440,255 MW (89.5 percent of demand) of uncleared bids. In the monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2006) of the 2006 to 2007 planning period, the total demand was 6,331,707 MW. The monthly Balance of Planning Period FTR Auctions cleared 380,147 MW (6 percent of demand), leaving 5,951,560 MW (94 percent of demand) of uncleared bids.

- **Market Concentration.** Ownership of FTR products is moderately concentrated and maximum market shares exceed 20 percent in some cases based on the results of the Annual FTR Auction. The FTR options market is more concentrated than the market for FTR obligations. Given PJM's Annual and monthly Balance of Planning Period FTR Auctions, the market shares may fluctuate when FTR-owning entities trade, buy or sell the instruments. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction.

5 The monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 planning period are referred to as Monthly FTR Auctions in any figure, table or text that also contains data for Monthly FTR Auctions prior to June 2006.

6 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Amended and Restated Operating Agreement, Docket No. ER06-1218-000 (July 3, 2006).

Market Performance

- **Volume.** Of 1,652,218 MW in annual FTR requests, including FTR allocations, for the 2006 to 2007 planning period, 208,068 MW (12.6 percent) were cleared. Of 914,483 MW in annual FTR requests for the 2005 to 2006 planning period, 180,608 MW (19.7 percent) were cleared. This volume included the demand and supply for directly allocated FTRs for the AEP, DAY, DLCO and Dominion Control Zones.

- **Price.** For the 2006 to 2007 planning period, 87.2 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 91.5 percent for less than $2 per MWh. For the 2006 to 2007 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $1.95 per MWh for 24-hour FTRs and $0.78 per MWh for both on-peak and off-peak FTRs. Comparable, weighted-average prices for the 2005 to 2006 planning period were $1.63 per MWh for 24-hour, $0.45 per MWh for on-peak and $0.19 per MWh for off-peak FTRs. The weighted-average prices paid for 2006 to 2007 planning period annual buy-bid FTR obligations and options were $1.12 per MWh and $0.29 per MWh, respectively, compared to $0.79 per MWh and $0.21 per MWh, respectively, in the 2005 to 2006 planning period.[7] The weighted-average price paid in the monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2006) of the 2006 to 2007 planning period was $0.29 per MWh, compared with $0.23 per MWh in the Monthly FTR Auctions for the 2005 to 2006 planning period.

- **Revenue.** Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,117 million of FTR revenues during the first seven months (June through December 2006) of the 2006 to 2007 planning period and $2,219 million during the 12-month 2005 to 2006 planning period.[8]

- **Revenue Adequacy.** FTRs were 91 percent revenue adequate for the 2005 to 2006 planning period. FTRs were paid at 100 percent of the target allocation level for the first seven months (June through December 2006) of the 2006 to 2007 planning period.[9] For the first seven months of the 2006 to 2007 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Western Hub, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations were the Western Hub and the Eastern Hub, respectively.

Auction Revenue Rights (ARRs)

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible.

7 Weighted-average prices for FTRs in the Annual FTR Auction and monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 planning period are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak. For example, FTRs in the Annual FTR Auction for the 2006 to 2007 planning period would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,080 hours) and off peak (4,680 hours).

8 See *2006 State of the Market Report,* Volume II, Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period."

9 See *2006 State of the Market Report,* Volume II, Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period" for an additional discussion of FTR revenue adequacy.

PJM submitted to the FERC revisions to the PJM OATT to include long-term ARRs for a duration of 10 planning periods.[10]

- **Demand.** Total demand in the annual ARR allocation was 99,412 MW for the 2006 to 2007 planning period with 56,705 MW bid in Stage 1 and 42,707 MW bid in Stage 2. This is up from 84,088 MW for the 2005 to 2006 planning period with 50,955 MW bid in Stage 1 and 33,133 MW bid in Stage 2.[11] ARR demand is limited by the total amount of network and long-term, firm point-to-point transmission service.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same zone is allocated a proportional share of positively valued ARRs within the zone based on the shifted load. There were 15,358 MW of ARRs associated with $307,500 per MW-day of revenue that were reassigned in the first seven months (June through December 2006) of the 2006 to 2007 planning period.

Market Performance

- **Volume.** Of 99,412 MW in ARR requests for the 2006 to 2007 planning period, 67,568 MW (68 percent) were allocated. There were 54,430 MW allocated in Stage 1 and 13,138 MW allocated in Stage 2. Eligible market participants self-scheduled 38,301 MW (56.7 percent) of these allocated ARRs as annual FTRs. Demand for ARRs increased because of load growth and the eligibility of the ComEd Control Zone to take ARR allocations, instead of direct allocation FTRs. Of 84,088 MW in ARR requests for the 2005 to 2006 planning period, 59,410 MW (70.7 percent) were allocated. There were 49,577 MW allocated in Stage 1 and 9,833 MW allocated in Stage 2. Eligible market participants self-scheduled 32,631 MW (54.9 percent) of these allocated ARRs as annual FTRs.

- **Revenue.** As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

- **Revenue Adequacy.** During the 2005 to 2006 planning period, ARR holders received $870 million in ARR credits, with an average hourly ARR credit of $1.67 per MWh. During the 2005 to 2006 planning period, the ARR target allocations were $870 million while PJM collected $898 million from the combined Annual and Monthly FTR Auctions, making ARRs revenue adequate. During the 2006 to 2007 planning period, ARR holders will receive $1,405 million in ARR credits, with an average hourly ARR credit of $2.37 per MWh. For the 2006 to 2007 planning period, the ARR target allocations were $1,405 million while PJM collected $1,432 million from the combined Annual and monthly Balance of Planning Period FTR Auctions through the end of calendar year 2006, making ARRs revenue adequate.

- **ARR Proration Issues.** When ARRs were allocated for the 2006 to 2007 planning period, some of the

10 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Amended and Restated Operating Agreement, Docket No. ER06-1218-000 (July 3, 2006).

11 The demand for the 2005 to 2006 planning period was listed as 82,343 MW in the *2005 State of the Market Report*. This number excluded individual ARR bid requests that did not clear any MW.

requested ARRs were prorated as a result of binding transmission constraints. For the 2006 to 2007 planning period, one of the major constraints affecting the allocation of ARRs was the Bedington-Black Oak Interface which usually has power flow from the west to the east. Over 700 MW of Stage 1 ARRs were denied to participants whose requested ARRs affected that transmission constraint. On August 1, 2006, two municipalities, the Borough of Chambersburg, Pennsylvania, and the Town of Front Royal, Virginia, filed a complaint with the FERC for review of the proration of their requested ARRs.[12] PJM filed an answer to the complaint on August 23, 2006.[13] The FERC denied the complaint on November 22, 2006.[14]

- **ARR and FTR Revenue and Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The first is to compare the revenue received by ARR holders against the congestion costs experienced by these ARR holders. The second is to compare the revenue received by FTR holders against the total congestion costs within PJM. The final and comprehensive method is to compare the revenue received by all ARR and FTR holders to total actual congestion costs in the Day-Ahead and Balancing Energy Market within PJM. During the 2005 to 2006 planning period, total ARR and FTR revenues hedged 99 percent of the congestion costs within PJM. For the first seven months (June through December 2006) of the 2006 to 2007 planning period, all ARRs and FTRs hedged 98.4 percent of the congestion costs within PJM.

Conclusion

The annual ARR allocation and the Annual FTR Auction together provide long-term, firm transmission customers with a mechanism to hedge congestion and provide all market participants increased access to long-term FTRs. The Annual FTR Auction and the monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR Auction Market results for the 2006 to 2007 planning year were competitive and succeeded in providing all qualified market participants with equal access to FTRs. The rules for ARR reassignment when load shifts should address the fact that in the case of ARRs self-scheduled as FTRs, the underlying FTRs do not follow the load while the ARR does. ARRs were 100 percent revenue adequate for both the 2005 to 2006 and the 2006 to 2007 planning periods. FTRs were paid at 91 percent of the target allocation level for the 12-month period of the 2005 to 2006 planning period, and at 100 percent of the target allocation level for the first seven months (June through December 2006) of the 2006 to 2007 planning period. The total of ARR and FTR revenues hedged 99 percent of the congestion costs in the Day-Ahead and Balancing Energy Market within PJM for the 2005 to 2006 planning period and 98.4 percent of the congestion costs in PJM in the first seven months of the 2006 to 2007 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across

12 *Front Royal, Town of*, Complaint of the Borough of Chambersburg, PA, and the Town of Front Royal, VA, against PJM Interconnection, L.L.C., Docket No. EL06-94-000 (August 1, 2006).

13 *Front Royal, Town of*, Answer of PJM Interconnection, L.L.C. to complaint, Docket No. EL06-94-000 (August 23, 2006).

14 117 FERC ¶ 61,219 (2006).

specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.

Financial Transmission Rights

While FTRs have been available to eligible participants since the 1998 introduction of LMPs, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. For the 2006 to 2007 planning period, the auction covered all control zones. Eligible participants in the AEP, DAY, DLCO and Dominion Control Zones received transitional, direct allocation FTRs at their option.[15]

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational price differences in the Day-Ahead Energy Market. The FTR target allocation is equal to the product of the FTR MW and the price differences between sink and source that occur in the Day-Ahead Energy Market. That price difference is also known as congestion. The value of an FTR can be positive or negative depending on these sink-minus-source price differences, with negative differences resulting in a liability for the holder.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. FTR holders with a negatively valued FTR are required to pay charges based on their target allocations. When FTR holders receive their target allocation, the associated FTRs are fully funded. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

There are two types of FTR product: FTR obligations and FTR options. An FTR obligation provides a credit, positive or negative, equal to the product of the FTR MW and the price difference between FTR sink and source that occurs in the Day-Ahead Energy Market. An FTR option provides only positive credits.

There are three standard FTR obligation and option products: 24-hour, on-peak and off-peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on-peak products are effective during on-peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Monday through Friday, excluding North American Electric Reliability Council (NERC) holidays. The off-peak products are effective during all other periods.

Market Structure

Prior to implementation of the Annual FTR Auction, only network service and long-term, firm point-to-point transmission service customers were able to directly obtain annual FTRs. Now all qualified market participants can participate in the Annual FTR Auction as well as the monthly Balance of Planning Period FTR Auctions. In addition, auction market participants are free to request FTRs between any pricing nodes on the system, not just from designated capacity resources to network load or solely along a long-term, firm point-to-point transmission service path.

15 AEP and DAY joined PJM on October 1, 2004. DLCO joined PJM on January 1, 2005. Dominion joined PJM on May 1, 2005.

Supply

The principal mechanism for obtaining FTRs is the Annual FTR Auction, including the ability to directly convert allocated ARRs into self-scheduled FTRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, transmission outages that are expected to last for two months or more are included, while outages of five days or more are included for the monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled. FTRs can also be obtained as direct allocation FTRs (available to customers in recently integrated control zones), in monthly Balance of Planning Period FTR Auctions and via bilateral trades of existing FTRs.

During the 2006 to 2007 planning period, binding constraints prevented the award of all requested FTRs in the Annual FTR Auction. Table 8-1 lists the top 10 binding constraints in order of severity, which is determined by the marginal value of the binding constraint. The marginal value is computed and generated in the optimization engine.[16] It is the amount of value to be gained by relieving a constraint by 1 MW.

Table 8-1 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2006 to 2007[17]

Constraint	Type	Control Zone
Laurel - Woodstown	Line	AECO
Bedington - Black Oak	Interface	AP
Mitchell - Shepler Hill	Line	AP
Wylie Ridge	Transformer	AP
Mount Storm - Doubs	Line	AP
Kammer	Transformer	AEP
5004/5005 Interface	Interface	NA
Bedington - Nipetown	Line	AP
Mahans Lane - Tidd	Line	AEP
Cedar Grove - Clifton	Line	PSEG

Annual FTR Auction

Each April, PJM conducts an Annual FTR Auction during which all eligible market participants can bid on FTRs for the next planning period consistent with total transmission system capability. The auction takes place over four rounds as follows:

- **Round 1.** Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on-peak or off-peak FTR obligations or FTR options. Locational prices are determined by

16 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), p. 52.

17 The constraint control zone identification for the 5004/5005 Interface is listed as NA (not applicable) because it cannot be assigned to a specific control zone.

maximizing the net revenue based on offer-based value of FTRs.[18] Auction participation is not restricted to any class of customers, and any market participant can make offers for available FTRs. ARR holders wishing to directly convert their previously allocated ARRs into self-scheduled FTRs must initiate that process in this round. One-quarter of each self-scheduled FTR clears as a 24-hour FTR in each of the four rounds. Self-scheduled FTRs must have the same source and sink as the corresponding ARR. Self-scheduled FTRs clear as price-taking FTR bids that are not eligible to set auction price.

- **Rounds 2 to 4.** Market participants make offers for FTRs. Locational prices are determined by maximizing the offer-based value of FTRs cleared. FTRs purchased in earlier rounds can be offered for sale in later rounds.

By self-scheduling ARRs as price-taking bids in the Annual FTR Auction, customers with ARRs receive FTRs for their ARR paths. ARR holders are guaranteed that they will receive their requested FTRs. ARRs can be self-scheduled only as 24-hour FTRs. ARR holders that self-schedule ARRs as FTRs still hold the associated ARR. Self-scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives the corresponding revenue based on holding the ARR and is left with ownership of the FTR as a hedge.

Monthly Balance of Planning Period FTR Auctions

Introduced at the beginning of the 2006 to 2007 planning period, the monthly Balance of Planning Period FTR Auctions make available the residual FTR capability on the PJM transmission system after the Annual FTR Auction and allow market participants to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the balance of the planning period. FTRs in the auctions can be either obligations or options and can be 24-hour, on-peak or off-peak products.[19]

Under the new auction rules, market participants may bid to buy or offer to sell FTRs that have the following terms. The first term is for one month for any of the next three months remaining in the planning period. For example, if the auction is conducted in May, any FTR valid for the months of June, July and August is included in the auction. The second term is for three months for any of the quarters remaining in the planning period (if technically feasible within the specified market timeframe). For example, for planning period quarter 1 (Q1), the auction period would be June, July and August. For planning period quarter 2 (Q2), the auction period would be September, October and November. Similarly, December, January and February would be for planning period quarter 3 (Q3) and March, April and May would be for planning period quarter 4 (Q4). For example, an auction held in May would have all four quarters available, while an auction held in June would include quarter 2, quarter 3 and quarter 4, but not quarter 1. Quarter 1 would be excluded because the first month of quarter 1 (June) would have passed and the quarters are auctioned in three-month periods only.

18 Annual and monthly Balance of Planning Period FTR Auctions determine nodal prices as a function of market participants' FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces maximum net revenue, thus maximizing the value of transmission assets. A feasible set of FTR bids is a set that does not impose a flow on any transmission facility in excess of its rating.

19 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 34-35.

Long-Term FTRs

On July 3, 2006, PJM submitted to the FERC revisions to the OATT to include long-term ARRs and FTRs with a duration of 10 planning periods.[20] Long-term FTRs would be obtained by directly converting long-term ARRs into self-scheduled FTRs. Long-term ARR holders could opt out of any planning period during the 10-planning-period timeline and self-schedule their long-term ARRs as FTRs. Long-term ARRs and FTRs would give LSEs the ability to hedge their congestion costs on a long-term basis by providing price certainty throughout the 10-planning-period-timeframe. The submission included an effective date of March 1, 2007, which would allow enough time to include long-term ARRs and FTRs for the 2007 to 2008 planning period. On November 22, 2006, the FERC issued an order accepting the revisions to the PJM OATT with the stipulation that they are subject to some modifications.[21]

Demand

Under the current rules, participants may submit unlimited bids for FTRs.

In addition to the Annual and monthly Balance of Planning Period FTR Auctions, FTRs can be traded between market participants through bilateral transactions. Eligible participants can trade FTRs through the PJM-administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral activity has increased from year to year since 2003.

When a new control zone is integrated into PJM, the participants in that control zone must choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive years following their integration date. After the two year transition period, such participants receive ARRs from the annual allocation process and are ineligible for directly allocated FTRs. Like other participants, they can receive FTRs by self-scheduling their allocated ARRs. For the 2006 to 2007 planning period (June 1, 2006, through May 31, 2007), ARR allocations were provided to eligible market participants in the Mid-Atlantic Region, and AP and ComEd Control Zones. The choice of ARRs or direct allocation FTRs was available in the recently integrated AEP, DAY, DLCO and Dominion Control Zones. Table 8-2 summarizes the availability of ARRs and direct allocation FTRs within the different regions and control zones.

20 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Amended and Restated Operating Agreement, Docket No. ER06-1218-000 (July 3, 2006).

21 117 FERC ¶ 61,220 (2006).

Table 8-2 Eligibility for ARRs vs. directly allocated FTRs

Region/Control Zone	PJM Integration Date	ARRs	Direct Allocation FTRs
Mid-Atlantic	1-Apr-99	Yes	No
AP	1-Apr-02	Yes	No
ComEd	1-May-04	Yes	No
AEP/DAY	1-Oct-04	Yes	Through 2006/2007 Planning Period
DLCO	1-Jan-05	Yes	Through 2006/2007 Planning Period
Dominion	1-May-05	Yes	Through 2006/2007 Planning Period

Table 8-3 shows that for the 2006 to 2007 planning period, 168,167 MW of annual FTR bids were cleared in the Annual FTR Auction for all control zones in the PJM footprint while 39,901 MW of annual FTR allocation requests were cleared in the annual FTR allocation for the AEP, DAY, DLCO and Dominion Control Zones.

In the direct allocation of FTRs for the AEP, DAY, DLCO and Dominion Control Zones, the total demand for annual FTR allocations was 43,796 MW for the 2006 to 2007 planning period. This is up from the 42,641 MW for the ComEd, AEP, DAY, DLCO and Dominion Control Zones in the 2005 to 2006 planning period. This includes the increase of 1,946 MW for the AEP Control Zone, the increase of 369 MW for the DAY Control Zone, the decrease of 337 MW for the DLCO Control Zone, the increase of 347 MW for the Dominion Control Zone and the decrease of 1,170 MW for the ComEd Control Zone as ComEd became ineligible for direct allocation FTRs.

Table 8-3 Annual FTR market volume: Planning period 2006 to 2007

	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume (Percent)	Uncleared Volume (MW)	Uncleared Volume (Percent)
Buy and Self-Scheduled Bids (Auction)						
All PJM Control Zones	192,358	1,608,422	168,167	10.5%	1,440,255	89.5%
Bid Requests (Direct Allocation)						
AEP	1,185	23,299	22,929	98.4%	370	1.6%
DAY	67	3,507	3,317	94.6%	190	5.4%
DLCO	22	295	186	63.1%	109	36.9%
Dominion	90	16,695	13,469	80.7%	3,226	19.3%
Total (Direct Allocation)	1,364	43,796	39,901	91.1%	3,895	8.9%
Grand Total (Auction and Direct Allocation)	193,722	1,652,218	208,068	12.6%	1,444,150	87.4%
Sell Offers (Auction)						
All PJM Control Zones	16,049	76,669	10,056	13.1%	66,613	86.9%

As Table 8-3 shows, annual FTR demand for both the auction and allocation in PJM was 1,652,218 MW during the 2006 to 2007 planning period, compared with 914,483 MW for the 2005 to 2006 planning period.

Table 8-4 shows that there were 6,331,707 MW of total demand for all bidding periods in the monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2006) of the 2006 to 2007 planning period. The monthly auctions cleared 380,147 MW (6 percent of demand) leaving 5,951,560 MW (94 percent of demand) of uncleared bids. The introduction of the monthly Balance of Planning Period FTR Auctions increased the demand for FTRs compared to the previous Monthly FTR Auctions. The Monthly FTR Auctions for the full 12-month 2005 to 2006 planning period had a total demand of 3,578,720 MW with 410,898 cleared MW (11.5 percent of demand) and 3,167,822 uncleared MW (88.5 percent of demand).

Table 8-4 Monthly balance of planning period FTR auction market volume: Planning period 2006 to 2007 through December 31, 2006

Monthly Auction	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume (Percent)	Uncleared Volume (MW)	Uncleared Volume (Percent)
Jun-06	Buy Bids	172,970	925,238	53,441	5.8%	871,797	94.2%
	Sell Offers	27,394	182,145	13,172	7.2%	168,973	92.8%
Jul-06	Buy Bids	206,527	934,424	53,102	5.7%	881,322	94.3%
	Sell Offers	33,880	214,929	21,439	10.0%	193,490	90.0%
Aug-06	Buy Bids	179,968	932,469	47,753	5.1%	884,716	94.9%
	Sell Offers	32,190	194,093	21,362	11.0%	172,731	89.0%
Sep-06	Buy Bids	183,711	841,698	52,350	6.2%	789,348	93.8%
	Sell Offers	30,671	211,625	15,000	7.1%	196,625	92.9%
Oct-06	Buy Bids	177,384	888,011	65,967	7.4%	822,044	92.6%
	Sell Offers	29,743	177,966	14,773	8.3%	163,193	91.7%
Nov-06	Buy Bids	161,447	890,318	50,626	5.7%	839,692	94.3%
	Sell Offers	21,315	125,142	10,516	8.4%	114,626	91.6%
Dec-06	Buy Bids	136,656	919,549	56,908	6.2%	862,641	93.8%
	Sell Offers	27,429	161,866	14,058	8.7%	147,808	91.3%
Total	Buy Bids	1,218,663	6,331,707	380,147	6.0%	5,951,560	94.0%
	Sell Offers	202,622	1,267,766	110,320	8.7%	1,157,446	91.3%
	Net	1,421,285	7,599,473	490,467	6.5%	7,109,006	93.5%

Market Concentration

The ownership concentration of FTR products resulting from the 2006 to 2007 Annual FTR Auction was low for FTR obligations and high for FTR options. This ownership information is only descriptive and is not a measure of actual or potential FTR market structure issues as the ownership positions resulted from a competitive auction. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the monthly Balance of Planning Period FTR Auctions or secondary bilateral market.

For FTR obligations, the Herfindahl-Hirschman Index (HHI) results were 815 for 24-hour, 998 for on-peak and 1008 for off-peak FTR products while maximum market shares were 15 percent for 24-hour, 21 percent for on-peak and 21 percent for off-peak FTR products.

For FTR options, HHIs were 6878 for 24-hour, 2016 for on-peak and 2568 for off-peak products while maximum market shares were 82 percent for 24-hour, 33 percent for on-peak and 37 percent for off-peak FTR products.

Market Performance

Volume

For the entire PJM footprint for the 2006 to 2007 planning period, 208,068 MW of annual FTRs, 168,167 MW from the Annual FTR Auction and 39,901 MW from direct allocation FTRs for new control zones, were purchased or allocated out of 1,652,218 MW bid and requested. (See Table 8-3.) For the 2006 to 2007 planning period, eligible market participants converted 38,301 MW of ARRs out of a possible 67,568 MW into annual FTRs. In comparison, during the 2005 to 2006 planning period, 180,608 MW were purchased or allocated out of 914,483 MW bid and requested. For the 2005 to 2006 planning period, eligible market participants converted 32,631 MW of ARRs into annual FTRs. Table 8-5 compares self-scheduled FTRs for the 2004 to 2005, the 2005 to 2006 and the 2006 to 2007 planning periods.

Table 8-5 Comparison of self-scheduled FTRs: Planning periods 2004 to 2005, 2005 to 2006 and 2006 to 2007

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2004/2005	13,061	33,589	38.9%
2005/2006	32,631	59,410	54.9%
2006/2007	38,301	67,568	56.7%

Price

Table 8-6 shows the cleared, weighted-average prices and volumes for annual FTR obligations and options during the 2005 to 2006 and the 2006 to 2007 planning periods. For the 2006 to 2007 planning period, weighted-average buy-bid FTR obligation prices were $1.12 per MWh with 80,680 MW cleared while weighted-average buy-bid FTR option prices were $0.29 per MWh with 49,186 MW cleared. Comparable weighted-average prices for the 2005 to 2006 planning period were $0.79 per MWh for buy-bid FTR obligations with 69,452 MW cleared and $0.21 per MWh for buy-bid FTR options with 39,096 MW cleared. For the 2006 to 2007 planning period, weighted-average sell offer FTR obligation prices were -$0.86 per MWh with 6,378 MW cleared while weighted-average sell offer FTR option prices were -$0.15 per MWh with 3,678 MW cleared. Comparable weighted-average prices for the 2005 to 2006 planning period were $0.07 per MWh for sell offer FTR obligations with 3,146 MW cleared and -$0.13 per MWh for sell offer FTR options with 1,397 MW cleared.

Table 8-6 Annual cleared average prices and volume for FTR obligations and options: Planning periods 2005 to 2006 and 2006 to 2007

Planning Period	Trade Type	Hedge Type	24-Hour ($/MWh)	24-Hour (MW)	On Peak ($/MWh)	On Peak (MW)	Off Peak ($/MWh)	Off Peak (MW)
2005/2006	Buy Bids	Obligations	$1.63	14,667	$0.45	31,426	$0.19	23,359
		Options	$0.05	3,329	$0.30	17,598	$0.19	18,169
	Self-Scheduled Bids	Obligations	$1.94	32,631	NA	NA	NA	NA
	Buy and Self-Scheduled Bids	Obligations	$1.85	47,298	$0.45	31,426	$0.19	23,359
	Sell Offers	Obligations	($0.49)	643	$0.75	1,339	($0.03)	1,164
		Options	$0.00	800	($0.52)	145	($0.46)	452
2006/2007	Buy Bids	Obligations	$1.95	13,516	$0.78	37,026	$0.78	30,138
		Options	$0.12	3,959	$0.39	24,625	$0.24	20,602
	Self-Scheduled Bids	Obligations	$2.77	38,301	NA	NA	NA	NA
	Buy and Self-Scheduled Bids	Obligations	$2.55	51,817	$0.78	37,026	$0.78	30,138
	Sell Offers	Obligations	($0.89)	2,346	$0.17	1,517	($1.34)	2,515
		Options	NA	NA	($0.16)	2,475	($0.14)	1,203

Table 8-7 shows the number, MW, weighted price and revenue for buy bids, self-scheduled bids, sell offers and net revenue for the Annual FTR Auction and monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 planning period. (Table 8-3 shows both annual FTR auction data and annual FTR allocation requests.) A total of 1,608,422 MW were bid and a total of 76,669 MW were offered in the Annual FTR Auction. By comparison, for the 2005 to 2006 planning period, a total of 871,841 MW were bid and requested and a total of 63,979 MW were offered.

On average during the 2006 to 2007 planning period in the Annual FTR Auction, self-scheduled FTRs were priced $1.95 per MWh higher than buy-bid FTRs. They were also priced $0.83 per MWh higher than the cleared, weighted-average price of self-scheduled FTRs from a year ago, while Mid-Atlantic Region, AP and ComEd Control Zone buy bids were up $0.48 per MWh from the weighted-average bid price of the 2005 to 2006 planning period.

The cleared, weighted-average price paid in the monthly Balance of Planning Period FTR Auctions during the first seven months (June through December 2006) of the 2006 to 2007 planning period was $0.29 per MWh (See Table 8-9.), compared with $0.23 per MWh in the Monthly FTR Auctions for the 2005 to 2006 planning period.

Table 8-7 Annual and monthly balance of planning period FTR auction volume, price and revenue: Planning period 2006 to 2007

	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Average Bid Price ($/MWh)	Average Cleared Price ($/MWh)	Revenue
Annual Auction						
Buy Bids	186,850	1,570,121	129,866	($0.31)	$0.82	$525,228,632
Self-Scheduled Bids	5,508	38,301	38,301	NA	$2.77	$927,747,627
Buy and Self-Scheduled Bids	192,358	1,608,422	168,167	($0.30)	$1.49	$1,452,976,259
Sell Offers	16,049	76,669	10,056	($0.84)	($0.65)	($35,468,499)
Net						$1,417,507,760
Monthly Auctions*						
Buy Bids	1,218,663	6,331,707	380,147	($0.68)	$0.29	$56,668,230
Sell Offers	202,622	1,267,766	110,320	($1.26)	($0.60)	($43,064,163)
Net						$13,604,067
*Shows 7 months ending 31-Dec-06						

The 2006 to 2007 planning period's price duration curve for cleared buy bids in Figure 8-1 shows that 87.2 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 91.5 percent for less than $2 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs.

Figure 8-1 Annual FTR auction-clearing price duration curve: Planning period 2006 to 2007

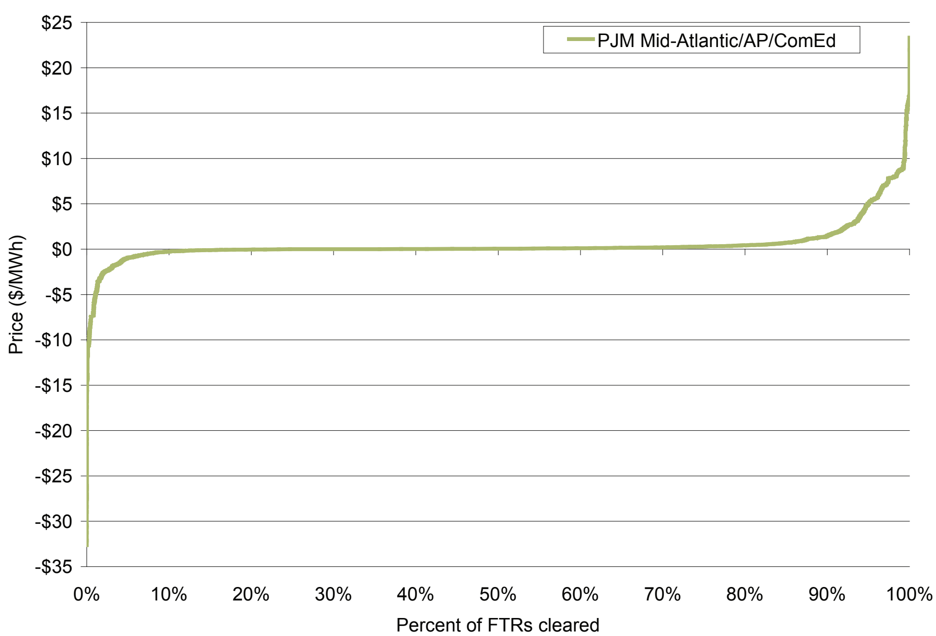


Figure 8-2 presents monthly FTR auction cleared buy-bid volume and average buy-bid clearing price. It shows that the average buy-bid clearing price dropped from 2002 to 2003 and 2004, but then rose in 2005 and dropped again in 2006. Volume steadily increased from 2002 through 2006.

Figure 8-2 Monthly FTR auction cleared buy-bid volume and average buy-bid price: Calendar years 2002 to 2006

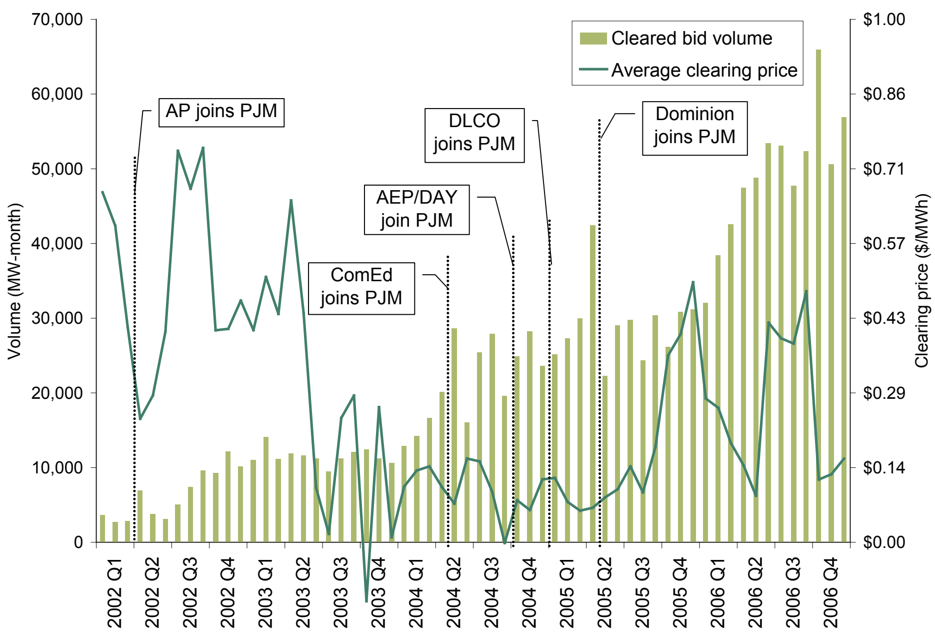


Table 8-8 and Table 8-9 show the monthly Balance of Planning Period FTR Auction results by bidding period for cleared buy-bid volume and average buy-bid price for June through December 2006. For example, for the June 2006 monthly Balance of Planning Period FTR Auction, the current month column is June, the second month column is July and the third month column is August. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents the sum of all of the activity within the June 2006 monthly Balance of Planning Period FTR Auction.

Table 8-8 Monthly balance of planning period FTR auction cleared buy-bid volume (MW per period): Planning period 2006 to 2007 through December 31, 2006

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jun-06	30,936	4,258	3,882	2,067	4,077	4,138	4,083	53,441
Jul-06	36,147	6,287	1,553		2,730	3,864	2,521	53,102
Aug-06	29,416	2,678	2,680		3,780	5,077	4,122	47,753
Sep-06	36,387	4,975	3,669		1,561	2,684	3,074	52,350
Oct-06	50,305	5,916	2,550			3,225	3,971	65,967
Nov-06	37,844	3,162	2,444			2,128	5,048	50,626
Dec-06	37,031	6,350	5,654			1,929	5,944	56,908
Total	258,066	33,626	22,432	2,067	12,148	23,045	28,763	380,147

Table 8-9 Monthly balance of planning period FTR auction cleared average buy-bid price per period ($/MWh): Planning period 2006 to 2007 through December 31, 2006

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jun-06	$0.22	$0.54	$0.28	$0.05	$0.34	$1.01	$0.60	$0.42
Jul-06	$0.35	$0.66	$0.06		$0.15	$0.67	$0.21	$0.39
Aug-06	$0.50	($0.07)	($0.23)		($0.11)	$0.69	$0.38	$0.38
Sep-06	$0.21	$0.12	($0.21)		$1.75	$1.19	$0.58	$0.48
Oct-06	$0.08	$0.16	($0.04)			$0.33	$0.14	$0.12
Nov-06	$0.10	$0.12	$0.20			$0.25	$0.13	$0.13
Dec-06	($0.01)	($0.09)	($0.34)			$1.88	$0.18	$0.16
Total	$0.19	$0.23	($0.07)	$0.05	$0.35	$0.81	$0.30	$0.29

Revenue

Table 8-7 shows annual FTR auction summary data. For the 2006 to 2007 planning period, the Annual FTR Auction for the ComEd and AP Control Zones and the Mid-Atlantic Region netted $1,417.5 million in revenue, with buyers paying $1,453 million and sellers receiving $35.5 million. For the 2005 to 2006 planning period, the Mid-Atlantic Region and the AP and ComEd Control Zones' Annual FTR Auction netted $881.6 million in revenue, with buyers paying $881.7 million and sellers receiving $0.1 million.

Annual FTR Auction Revenue

Figure 8-3 summarizes total revenue associated with all FTRs, regardless of source, to the 10 FTR sinks (destinations) that produced the most annual FTR auction revenue for the 2006 to 2007 planning period. FTRs to these sinks accounted for $1,278 million or about 88 percent of all revenue paid in the Annual FTR Auction and constituted 29.4 percent of all FTRs bought in the Annual FTR Auction for the 2006 to 2007 planning period.[22]

Figure 8-3 Highest revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2006 to 2007

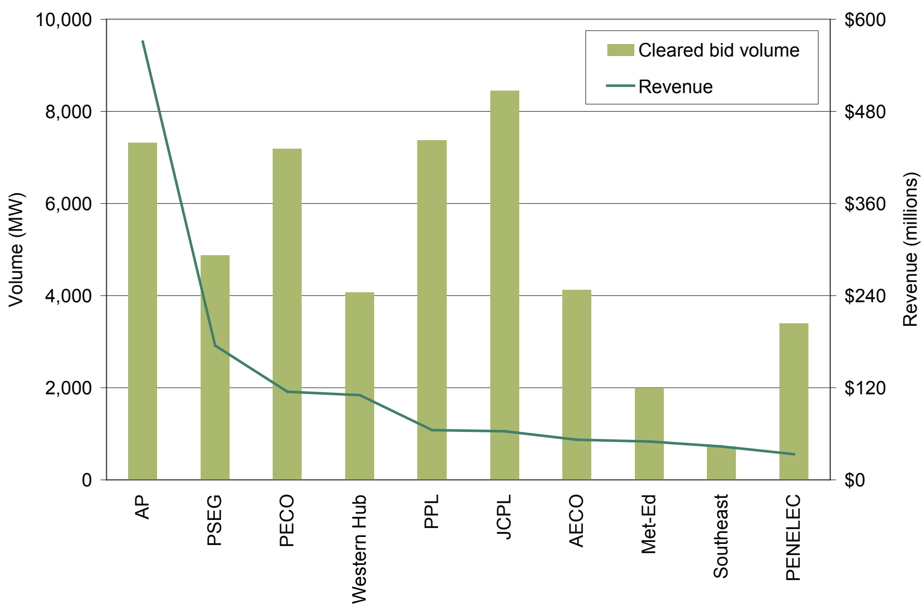


Figure 8-4 summarizes total revenue associated with all FTRs, regardless of sink, from the 10 FTR sources (origins) that produced the most annual FTR auction revenue for the 2006 to 2007 planning period. FTRs from these sources accounted for $1,056 million or about 72.7 percent of all revenue paid and included 14.4 percent of all FTRs bought in the Annual FTR Auction. These sources are generally located at large generating facilities throughout the Mid-Atlantic Region.

22 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These payments reduce the amount of net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

Figure 8-4 Highest revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2006 to 2007

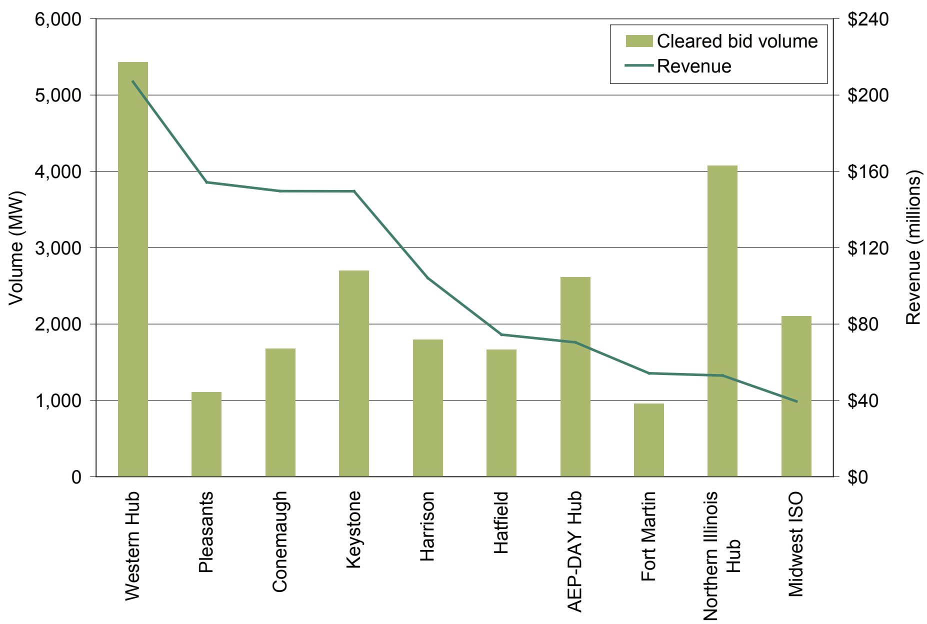


Table 8-10 shows the corresponding control zones for the FTR sinks (See Figure 8-3.) and sources (See Figure 8-4.) that produce the highest revenue in the Annual FTR Auction for the 2006 to 2007 planning period.

Table 8-10 Corresponding control zones for the highest revenue producing FTR sinks and sources in the Annual FTR Auction: Planning period 2006 to 2007[23]

FTR Sinks	FTR Sink Control Zone	FTR Sources	FTR Source Control Zone
AP	AP	Western Hub	NA
PSEG	PSEG	Pleasants	AP
PECO	PECO	Conemaugh	AP
Western Hub	NA	Keystone	AP
PPL	PPL	Harrison	AP
JCPL	JCPL	Hatfield	AP
AECO	AECO	AEP-DAY Hub	NA
Met-Ed	Met-Ed	Fort Martin	AP
Southeast	Dominion	Northern Illinois Hub	NA
PENELEC	PENELEC	Midwest ISO	External

23 FTR sink and source control zone identifications for hubs and pricing points are listed as NA because they cannot be assigned to a specific control zone.

Monthly Balance of Planning Period FTR Auction Revenue

Figure 8-5 summarizes total revenue associated with all FTRs, regardless of source, to the 10 FTR sinks that produced the most monthly balance of planning period FTR auction revenue during the first seven months of the 2006 to 2007 planning period. FTRs to these sinks accounted for $84 million and 13.5 percent of all FTRs bought in the monthly Balance of Planning Period FTR Auctions.

Figure 8-5 Highest revenue producing FTR sinks purchased in the monthly Balance of Planning Period FTR Auctions: Planning period 2006 to 2007 through December 31, 2006

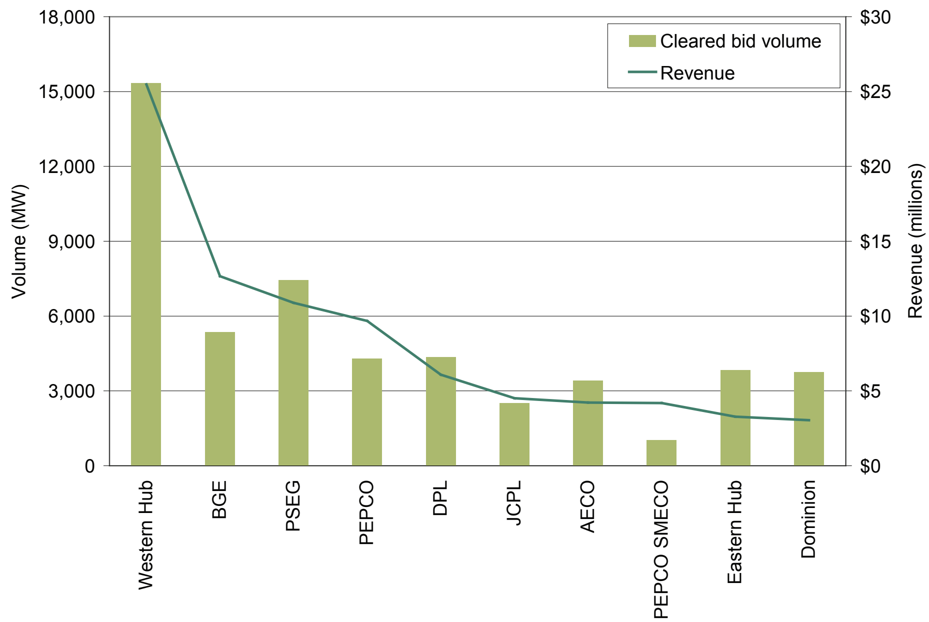


Figure 8-6 summarizes total revenue associated with all FTRs, regardless of sink, from the 10 FTR sources that produced the most monthly balance of planning period FTR auction revenue during the first seven months of the 2006 to 2007 planning period. FTRs from these sources accounted for $110 million and 11.1 percent of all FTRs bought in monthly Balance of Planning Period FTR Auctions.

Figure 8-6 Highest revenue producing FTR sources purchased in the monthly Balance of Planning Period FTR Auctions: Planning period 2006 to 2007 through December 31, 2006

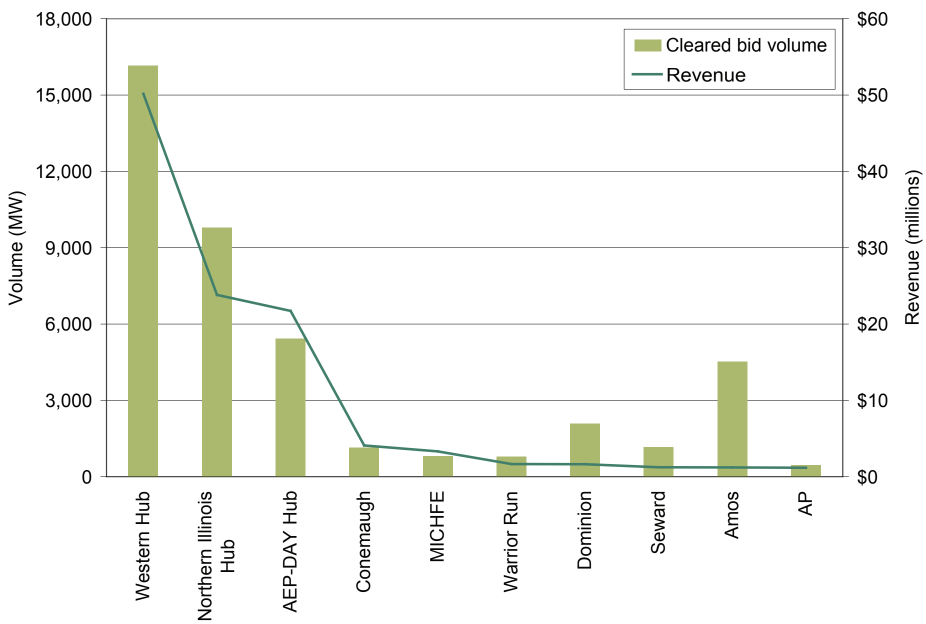


Table 8-11 shows the corresponding control zones for the FTR sinks (See Figure 8-5.) and sources (See Figure 8-6.) that produce the highest revenue in the monthly Balance of Planning Period FTR Auctions for the first seven months of the 2006 to 2007 planning period.

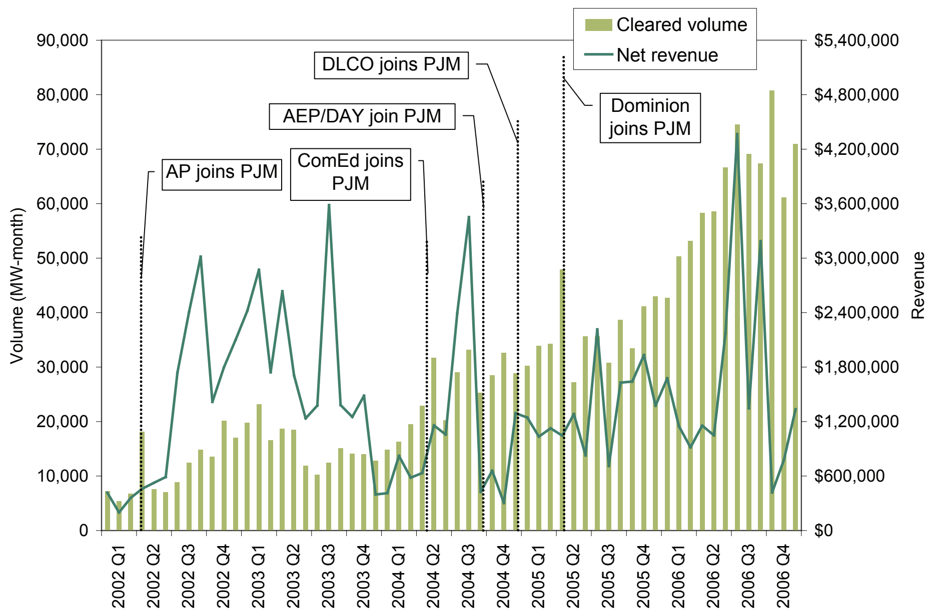
Table 8-11 Corresponding control zones for the highest revenue producing FTR sinks and sources in the monthly Balance of Planning Period FTR Auctions: Planning period 2006 to 2007 through December 31, 2006 [24]

FTR Sinks	FTR Sink Control Zone	FTR Sources	FTR Source Control Zone
Western Hub	NA	Western Hub	NA
BGE	BGE	Northern Illinois Hub	NA
PSEG	PSEG	AEP-DAY Hub	NA
PEPCO	PEPCO	Conemaugh	AP
DPL	DPL	MICHFE	NA
JCPL	JCPL	Warrior Run	AP
AECO	AECO	Dominion	Dominion
PEPCO SMECO	PEPCO	Seward	PENELEC
Eastern Hub	NA	Amos	AEP
Dominion	Dominion	AP	AP

24 FTR sink and source control zone identifications for hubs and pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 8-7 depicts the total cleared bid and offer volume together with the total auction revenue generated in the Monthly FTR Auctions during calendar years 2002 through 2006. Average monthly revenue for the period January 1, 2006, through December 31, 2006, was about $1.63 million per month. The average volume for the same period was 62,789 MW-month. This traded volume has significantly increased from that of calendar year 2005, which was 35,966 MW-month.

Figure 8-7 Monthly FTR auction cleared volume and net revenue: Calendar years 2002 to 2006



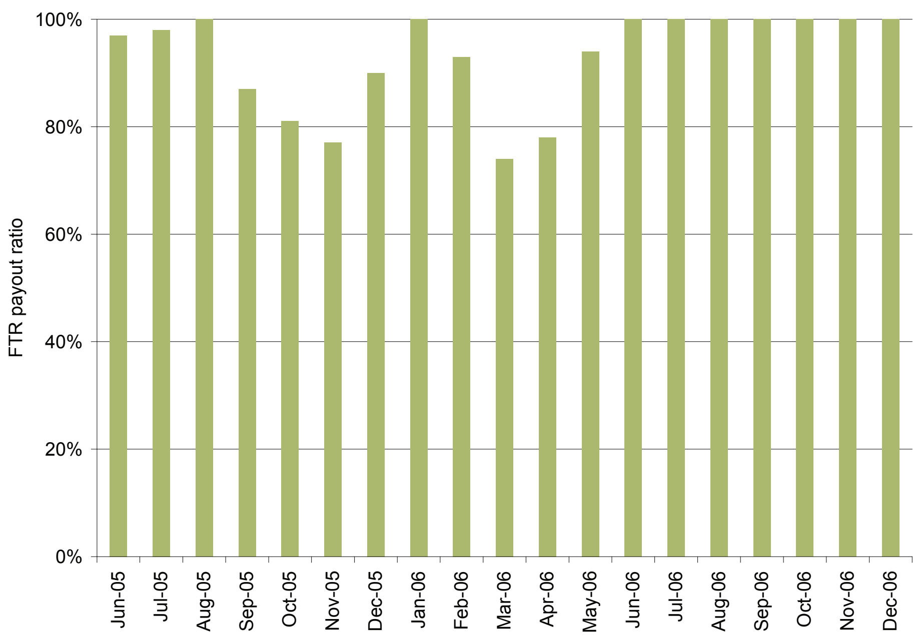
Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The MW of load exceeds the MW of generation in constrained areas because a part of the load is served by imports using transmission capability into the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in a constrained area receives the congested price and all load in the constrained area pays the congested price. As a result, load congestion payments are usually greater than the congestion-related increase in payments to generation. An illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined is provided in Table G-1, “Congestion revenue, FTR target allocations and FTR congestion credits: Illustration,” in Appendix G, “Financial Transmission and Auction Revenue Rights.” In general, FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and equal the revenue required to hedge FTR holders fully against congestion on the specific paths for which the FTRs are held. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Figure 8-8 shows the monthly FTR payout ratio from June 2005 through December 2006.[25] FTRs were paid at 91 percent of the target allocations for the 2005 to 2006 planning period. FTRs through December 31, 2006, of the 2006 to 2007 planning period have been paid at 100 percent of the target allocation level.[26]

Figure 8-8 Monthly FTR payout ratio: June 2005 to December 2006



FTR target allocations were examined separately. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2006 to 2007 planning period through December 31, 2006. Figure 8-9 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 75.4 percent of total positive

25 See *2006 State of the Market Report*, Volume II, Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period."

26 For full congestion accounting and FTR revenue adequacy data, see *2006 State of the Market Report*, Volume II, Section 7, "Congestion."

target allocations. FTRs with the top three sinks, the AP, AEP and Dominion Control Zones, included 54.4 percent of all positive target allocations. The top 10 sinks that created liability accounted for 42.2 percent of total negative target allocations. FTRs with the Western Hub as the sink encompassed 10.5 percent of all negative target allocations.

Figure 8-9 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2006 to 2007 through December 31, 2006

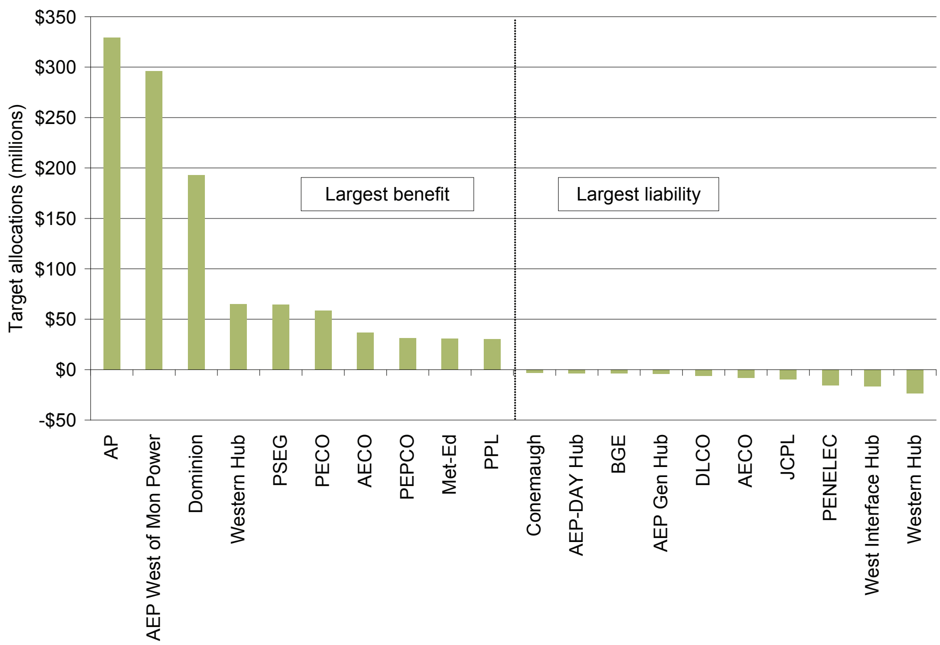
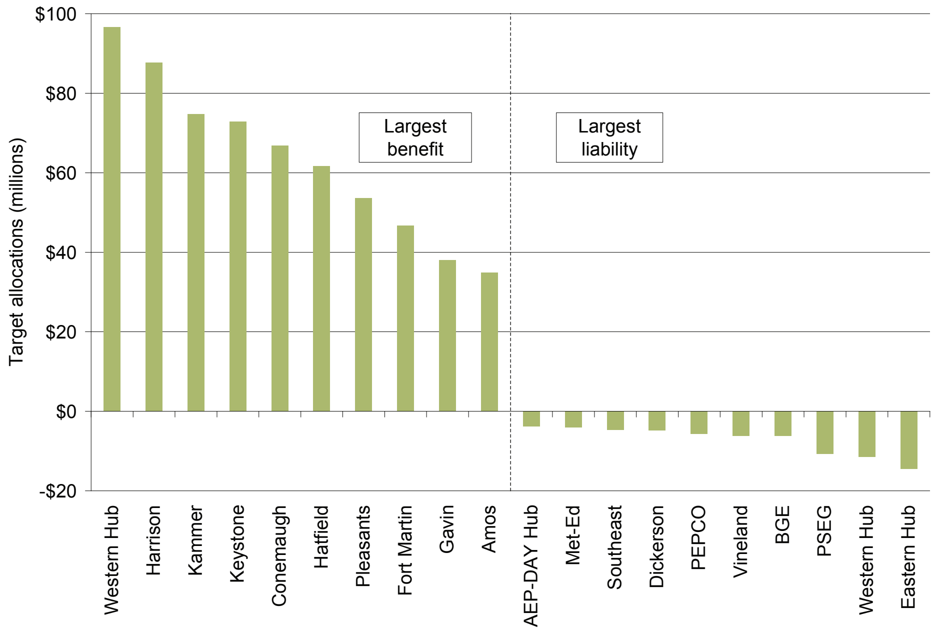


Figure 8-10 shows the FTR sources with the largest positive and negative target allocations. The top 10 sources with a positive target allocation accounted for 42.1 percent of total positive target allocations. All of these 10 sources were located in the AP and AEP Control Zones. FTRs with the Western Hub as their source included 6.4 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 32.2 percent of total negative target allocations. FTRs with the Eastern Hub as the source encompassed 6.5 percent of all negative target allocations.

Figure 8-10 Ten largest positive and negative FTR target allocations summed by source: Planning period 2006 to 2007 through December 31, 2006



Auction Revenue Rights

FTRs and ARRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational price differences actually experienced in the Day-Ahead Energy Market while ARRs are financial instruments that entitle their holders to receive revenue or pay charges based on prices determined in the Annual FTR Auction.[27] These price differences are based on the bid prices of participants in the Annual FTR Auction. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational price differences in the Day-Ahead Energy Market.

The ARR target allocation is equal to the product of the ARR MW and the price differences between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on these price differences, with negative differences resulting in a liability for the holder. Based on the annual and monthly balance of planning period FTR auction revenue, ARR holders are granted credits that can be positive or negative and that can range from zero to the target allocations.

ARRs have been available to eligible participants since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region

27 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

and the AP Control Zone. During the 2006 to 2007 planning period, the ComEd Control Zone was allocated ARRs. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the new AEP, DAY, DLCO and Dominion Control Zones. After their integration dates, market participants in the new control zones have two planning periods during which they are eligible for transitional allocation of FTRs or ARRs. After that transition, market participants are subject to the ARR allocation rules. When load shifts from one LSE to another in newly integrated control zones, directly allocated FTRs with positive economic value follow the load.[28]

In response to a 2004 order by the FERC, PJM proposed changes to its ARR allocation process that would allow certain long-term, firm point-to-point transmission service customers to participate in Stage 1 of the annual ARR allocation.[29] In a March 7, 2005, order effective the following day, the FERC approved the proposed changes in the allocation rules, allowing network and point-to-point customers to participate on the same basis in the first and second stages of ARR allocation.[30] The rules were approved before the start of the Stage 1 ARR allocation process and became effective for the 2005 to 2006 planning period and subsequent years.

For the 2006 to 2007 planning period, no mitigation credits were required for newly integrated control zones, as was required in the 2004 to 2005 planning period because long-term, firm point-to-point transmission customers can participate in the Stage 1 ARR allocation on an equal footing with network service transmission customers. Similarly, there were no mitigation credits required during the 2005 to 2006 planning period.

Market Structure

Supply

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible.

ARR Allocation

Network service and long-term, firm point-to-point transmission customers can request ARRs up to the amount of their transmission service.[31] Network service customers may request ARRs up to their peak-load value, while qualifying firm transmission customers may request ARRs based on MW of firm service provided between receipt and delivery points for which the transmission customer had point-to-point transmission service during the reference year.[32, 33]

28 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 32-33.

29 106 FERC ¶ 61,049 (2004).

30 110 FERC ¶ 61,254 (2005).

31 Network service transmission customers have reliability obligations to supply load at one or more points on the system and must obtain capacity plus reserves from qualified capacity resources. Firm point-to-point transmission customers have reserved transmission capability between two points that is usually used to deliver resources into or out of the RTO. Both types of customers are referred to as eligible customers in this section.

32 Any firm transmission customers with an agreement for long-term, point-to-point transmission service that is used to deliver energy from a designated network resource to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the zone in which the resource is located.

33 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 22-26.

Each March, PJM allocates annual ARRs to eligible customers in a two-stage process, where the first stage is one round and the second stage is a four-round allocation procedure:

- **Stage 1.** In the first stage of the allocation, network service customers can obtain ARRs, up to their peak-load share, based on generation resources that historically have served load in each control zone or load aggregation zone.[34] Firm point-to-point customers can obtain ARRs based on the MW of firm, long-term point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term, point-to-point service agreements must also remain in effect for the period covered by the allocation.

- **Stage 2.** The second stage of the allocation is a four-step procedure, with 25 percent of remaining system capability allocated in each step of the process. Network service transmission customers can obtain ARRs from any generator bus, hub, zone or interface to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in the first stage. Firm point-to-point customers can obtain ARRs consistent with their transmission service as in Stage 1.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a powerflow model of security-constrained dispatch that takes into account generation and transmission facilities' outages and is based on reasonable assumptions about the configuration and availability of transmission capability during the planning period.[35] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all of the resulting ARR obligations, preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated pro rata shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints.

Equation 8-1 Calculation of prorated ARRs

Individual pro rata MW = (Constraint capability) · (Individual requested MW / Total requested MW) · (1 / per MW effect on line)[36]

Market participants constructing transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability.[37] Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, in place of continuing this 30-year ARR, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall system simultaneous feasibility can be maintained.

34 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), p. 18.

35 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 49-50.

36 See *2006 State of the Market Report*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

37 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 27-28.

ARRs associated with firm transmission service that spans the entire next planning period, outside of the annual ARR allocation window, can be requested through the PJM Open Access Same-Time Information System (OASIS).[38]

Prior to the start of the Stage 2 ARR allocation process, a participant can relinquish any portion of the ARR awards resulting from the Stage 1 allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[39] Participants may seek additional ARRs in the Stage 2 allocation. For the 2006 to 2007 planning period, no ARRs were relinquished after the Stage 1 ARR allocation. In comparison, eligible customers relinquished 270 MW of the allocated ARRs after the Stage 1 ARR allocation for the 2005 to 2006 planning period.

Table 8-12 lists the top 10 principal binding constraints in order of severity that limited supply in the annual ARR allocation for the 2006 to 2007 planning period. The order of severity is determined by the violation degree of the binding constraint, which is computed in the simultaneous feasibility test.[40] The violation degree is a measure of the amount of MW that a constraint is over the limit for a type of facility, where a higher number indicates a more severe constraint.

Table 8-12 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2006 to 2007[41]

Constraint	Type	Control Zone
AP South	Interface	AP
Conesville - Corridor	Line	AEP
Mount Storm - Doubs	Line	AP
East Frankfort - Goodings	Line	ComEd
Cedar Grove - Clifton	Line	PSEG
Silver Lake - Cherry Valley	Line	ComEd
East	Interface	NA
Bedington - Black Oak	Interface	AP
North East - Darbytown	Line	Dominion
Beatty - Adkins	Line	AEP

Long-Term ARRs

On July 20, 2006, the FERC issued an order amending its regulations under the Federal Power Act to require transmission organizations that are public utilities with organized electricity markets to make available long-term firm transmission rights that satisfy certain conditions within the final rule.[42] Before the final rule, on July 3, 2006, PJM submitted to the FERC revisions to the OATT to include long-term ARRs and FTRs

38 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 19-20.

39 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 22-24.

40 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 49-50.

41 The constraint control zone identification for the East Interface is listed as NA because it cannot be assigned to a specific control zone.

42 116 FERC ¶ 61,077 (2006).

for a duration of 10 planning periods.[43] Long-term FTRs would be obtained through the self-scheduling of long-term ARRs. PJM requested an effective date of March 1, 2007, which would allow enough time for the implementation of long-term ARRs and FTRs for the 2007 to 2008 planning period. The revisions to PJM's OATT are an extension and modification to the current annual ARR allocation process. They would create a three-stage annual ARR allocation process, where the first and second stages are each one round, and the third stage is a three-round allocation procedure:

- **Stage 1A.** In the first stage of the allocation, network service customers can obtain long-term ARRs, up to their share of the zonal base load, based on generation resources that historically have served load in each control zone and up to 50 percent of their historical non-zone network load. Non-zone network load is load that is located outside of the PJM Region. Firm point-to-point customers can obtain long-term ARRs, based on up to 50 percent of the MW of firm, long-term, point-to-point service provided between the receipt and delivery points for the historical reference year. Stage 1A ARR holders can also opt out of any planning period during the 10-planning-period timeline and self-schedule their long-term ARRs as FTRs.

- **Stage 1B.** The ARRs not allocated in Stage 1A are available in the Stage 1B allocation. Network service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for non-zone network load. Firm point-to-point customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.

- **Stage 2.** The third stage of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network service transmission customers can obtain ARRs from any generator bus, hub, zone or interface to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm point-to-point customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

The reduction in the number of rounds from four to three for the Stage 2 allocation is to keep the total number of rounds in the annual ARR allocation process at five so as to maintain the efficiency of the annual ARR allocation process. All ARRs, including Stage 1A long-term ARRs, must be simultaneously feasible. The PJM proration method will be applied to ARRs that are not feasible. On November 22, 2006, the FERC issued an order accepting the revisions to the PJM OATT with the stipulation that they are subject to modifications.[44]

43 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Amended and Restated Operating Agreement, Docket No. ER06-1218-000 (July 3, 2006).

44 117 FERC ¶ 61,220 (2006).

Demand

ARR demand was 99,412 MW for the 2006 to 2007 planning period, up from 84,088 MW for the 2005 to 2006 planning period. Demand for ARRs increased because of load growth and the requirement for the ComEd Control Zone to select ARR allocations, instead of direct allocation FTRs.

PJM's OATT specifies the types of transmission services that are available to eligible customers. Eligible customers submit requests to PJM for network and firm point-to-point transmission service through the PJM OASIS. PJM evaluates each transmission service request for its impact on the system and approves or denies the request accordingly. All approved transmission services can be accommodated by the PJM transmission system. Theoretically, since total eligible ARR demand for the system cannot exceed the combined MW of network and firm point-to-point transmission service, ARR supply should equal ARR demand if ARR nominations are consistent with the historic use of the transmission system. Nonetheless, the demand for some ARRs could be left unmet if the same resources are nominated as ARR source points by multiple parties for delivery across shared paths and the result exceeds the stated capability of the transmission system to deliver from those sources to load. The combination might not be simultaneously feasible. When the requested set of ARRs is not simultaneously feasible, customers are allocated pro rata shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints.

ARR Reassignment for Retail Load Switching

Current PJM rules provide that when load switches among LSEs during the planning period, a proportional share of associated ARRs within a given control or load aggregation zone is automatically reassigned to follow that load.[45] ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same zone is allocated a proportional share of positively valued ARRs within the zone based on the shifted load. Any MW of load may be reassigned multiple times over a planning period. This rule supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self-scheduled as FTRs, these underlying self-scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the hedge.

Table 8-13 and Table 8-14 summarize ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2004 and December 2006. About 15,358 MW of ARRs associated with $307,500 per MW-day of revenue were automatically reassigned in the first seven months (June through December 2006) of the 2006 to 2007 planning period. About 18,080 MW of ARRs with $296,700 per MW-day of revenue were reassigned for the 2005 to 2006 planning period and about 22,752 MW associated with $173,600 per MW-day of revenue were reassigned for the 2004 to 2005 planning period.

45 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 26-27.

Table 8-13 ARRs automatically reassigned for network load changes by control zone (MW-day): June 1, 2004, to December 31, 2006

Control Zone	2004/2005 (12 months)	2005/2006 (12 months)	2006/2007 (7 months)*
AECO	181	530	84
AEP	94	220	38
AP	188	678	276
BGE	4,383	3,026	5,566
ComEd	3,288	4,211	4,236
DAY	48	4	3
DLCO	364	847	625
Dominion	0	74	1
DPL	2,461	2,250	928
JCPL	784	1,301	322
Met-Ed	108	120	207
PECO	830	443	70
PENELEC	73	87	118
PEPCO	8,507	2,806	2,185
PPL	219	87	17
PSEG	1,206	1,291	675
RECO	18	105	7
Total	22,752	18,080	15,358
* Through 31-Dec-06			

Table 8-14 ARR revenue automatically reassigned for network load changes by control zone [Dollars (thousands) per MW-day]: June 1, 2004, to December 31, 2006

Control Zone	2004/2005 (12 months)	2005/2006 (12 months)	2006/2007 (7 months)*
AECO	$4.3	$17.4	$3.5
AEP	$0.0	$5.0	$1.0
AP	$0.0	$75.2	$57.0
BGE	$41.7	$45.1	$136.3
ComEd	$0.1	$12.3	$4.5
DAY	$0.0	$0.0	$0.0
DLCO	$0.0	$8.2	$2.0
Dominion	$0.0	$0.0	$0.0
DPL	$34.5	$29.8	$12.8
JCPL	$10.9	$23.6	$7.4
Met-Ed	$1.3	$3.2	$10.1
PECO	$15.3	$16.3	$2.7
PENELEC	$2.0	$1.9	$5.7
PEPCO	$29.2	$20.5	$41.3
PPL	$2.0	$1.8	$0.7
PSEG	$32.3	$35.8	$22.5
RECO	$0.0	$0.6	$0.0
Total	$173.6	$296.7	$307.5
* Through 31-Dec-06			

Market Performance

Volume

Table 8-15 lists the annual ARR allocation volume for the 2004 to 2005, the 2005 to 2006 and the 2006 to 2007 planning periods. For the 2006 to 2007 planning period, there were 56,705 MW (57 percent of demand) bid in Stage 1 and 42,707 MW (43 percent of demand) bid in Stage 2. Of 99,412 MW in total ARR requests, 54,430 MW were allocated in Stage 1 while 13,138 MW were allocated in Stage 2 for a total of 67,568 MW (68 percent) allocated. Eligible market participants subsequently converted 38,301 MW of these allocated ARRs into annual FTRs (56.7 percent of total allocated ARRs), leaving 29,267 MW of ARRs outstanding. For the 2005 to 2006 planning period, there had been 50,955 MW (60.6 percent of demand) bid in Stage 1 and 33,133 MW (39.4 percent of demand) bid in Stage 2. Of 84,088 MW in total ARR requests for the 2005 to 2006 planning period, 49,577 MW were allocated in Stage 1 while 9,833 MW were allocated in Stage 2 for a total of 59,410 MW (70.7 percent) allocated. There were 32,631 MW or 54.9 percent of the allocated ARRs converted into FTRs.

Table 8-15 Annual ARR allocation volume: Planning periods 2004 to 2005, 2005 to 2006 and 2006 to 2007

Planning Period	Stage	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume (Percent)	Uncleared Volume (MW)	Uncleared Volume (Percent)
2004/2005	1	3,582	22,576	21,820	96.7%	756	3.3%
	2	3,296	32,552	11,769	36.2%	20,783	63.8%
	Total	6,878	55,128	33,589	60.9%	21,539	39.1%
2005/2006	1	6,348	50,955	49,577	97.3%	1,378	2.7%
	2	3,462	33,133	9,833	29.7%	23,300	70.3%
	Total	9,810	84,088	59,410	70.7%	24,678	29.3%
2006/2007	1	7,294	56,705	54,430	96.0%	2,275	4.0%
	2	3,579	42,707	13,138	30.8%	29,569	69.2%
	Total	10,873	99,412	67,568	68.0%	31,844	32.0%

Revenue

As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

The degree to which ARR credits provide a hedge against congestion on specific ARR paths is determined by the prices that result from the Annual FTR Auction. The resultant ARR credit could be greater than, less than, or equal to the actual congestion on the selected path. This is the same concept as FTR revenue adequacy.

Customers that are allocated ARRs can choose to retain the underlying FTRs linked to their ARRs through a process termed self-scheduling. Just like any other FTR, the underlying FTRs have a target hedge value based on actual day-ahead congestion on the selected path.

An ARR target allocation defines revenue that an ARR holder should receive and is equal to the product of the ARR MW and the price difference between ARR sink and source established during the Annual FTR Auction. FTR auction revenue is the net revenue from the auction. The prices that result from the Annual FTR Auction are the result of bids based on participants' expectations about the level of congestion in the Day-Ahead Energy Market. All ARR holders receive ARR credits equal to their target allocations if total net annual and monthly balance of planning period FTR auction revenues are greater than, or equal to, the sum of all ARR target allocations. If the combined net annual and monthly balance of planning period FTR auction revenues are less than that, the available revenue is proportionally allocated among all ARR holders.

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which ARRs were available and allocated. The adequacy of

ARRs as a hedge against congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs hedged market participants against actual, total congestion into their zone, regardless of the availability or allocation of ARRs.

ARR holders will receive $1,405 million in credits from the Annual FTR Auction during the 2006 to 2007 planning period, with an average hourly ARR credit of $2.37 per MWh. During the comparable 2005 to 2006 planning period, ARR holders received $870 million in ARR credits, with an average hourly ARR credit of $1.67 per MWh.

Table 8-16 lists ARR target allocations and net revenue sources from the Annual and Monthly FTR Auctions for the 2004 to 2005, the 2005 to 2006 and the 2006 to 2007 (through December 31, 2006) planning periods. Annual FTR auction net revenue has been sufficient to cover ARR target allocations for all three planning periods. The 2006 to 2007 planning period's Annual and monthly Balance of Planning Period FTR Auctions generated a surplus of $27 million in auction net revenue through December 31, 2006, above the amount needed to pay 100 percent of ARR target allocations. The whole 2005 to 2006 planning period's Annual and Monthly FTR Auctions generated a surplus of $28 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 8-16 ARR revenue adequacy [Dollars (millions)]: Planning periods 2004 to 2005, 2005 to 2006 and 2006 to 2007

	2004/2005	2005/2006	2006/2007
Total FTR Auction Net Revenue	$385	$898	$1,432
Annual FTR Auction Net Revenue	$370	$882	$1,418
Monthly FTR Auction Net Revenue*	$15	$16	$14
ARR Target Allocations	$345	$870	$1,405
ARR Credits	$345	$870	$1,405
Surplus Auction Revenue	$40	$28	$27
ARR Payout Ratio	100%	100%	100%

* Shows 12 months for 2004/2005 and 2005/2006, and 7 months ending 31-Dec-06 for 2006/2007

ARR Proration Issues

During the annual ARR allocation process, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. If all the ARR requests made during the annual ARR allocation process are not feasible, then ARRs are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.[46, 47]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power

46 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 25-26.

47 See *2006 State of the Market Report*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining the ARR prorating method.

flow on the binding constraint. The PJM method prorates those ARR requests that have the greatest impact on the binding constraint rather than prorating a greater number of requests with smaller or minimal impact on the binding constraint. PJM's method results in the prorating of ARRs that cause the greatest flows on the binding constraint rather than those that produce less flow on the binding constraint. Were all ARR requests prorated equally, irrespective of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs even when they have little impact on the binding constraints and the reduction of ARRs, and their associated benefits, with primary impacts on unrelated constraints.

When ARRs were allocated for the 2006 to 2007 planning period, some of the requested ARRs were prorated in order to ensure simultaneous feasibility. For the 2006 to 2007 planning period, one of the major constraints limiting the allocation of ARRs was the Bedington-Black Oak Interface. In all, over 2,500 MW of Stage 1 ARR requests, with approximately 700 MW of these attributable to the Bedington–Black Oak Interface, were denied based on the application of PJM's proration method.

A number of factors caused the proration of requested ARRs associated with the binding Bedington–Black Oak Interface transmission limitation. They include an increase in ARR requests for congested paths on the Bedington–Black Oak Interface, general load growth and increased unscheduled transmission flow across the PJM system from external sources.

On August 1, 2006, two municipalities, the Borough of Chambersburg, Pennsylvania, and the Town of Front Royal, Virginia, filed a complaint with the FERC regarding the proration of their requested ARRs.[48] PJM filed an answer to the complaint on August 23, 2006.[49] In a November 22, 2006, order, the FERC denied the complaint and found that PJM had correctly applied the rules within its OATT and that it would not be appropriate to rerun the annual ARR allocation process for the 2006 to 2007 planning period because parties had already made commitments based on those ARR allocations.[50] On, December 21, 2006, the Borough of Chambersburg, Pennsylvania, and the Town of Front Royal, Virginia, submitted to the FERC a request for a rehearing of their complaints.[51]

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 8-11 shows annual FTR auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone based on the difference between zonal prices and Western Hub prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $6.89 per MWh in the Annual FTR Auction and that about $3.04 per MWh of day-ahead congestion and $1.87 per MWh of real-time congestion existed between the Western Hub and the control zone. The data show that congestion costs, approximated

48 *Front Royal, Town of,* Complaint of the Borough of Chambersburg, PA, and the Town of Front Royal, VA, against PJM Interconnection, L.L.C., Docket No. EL06-94-000 (August 1, 2006).

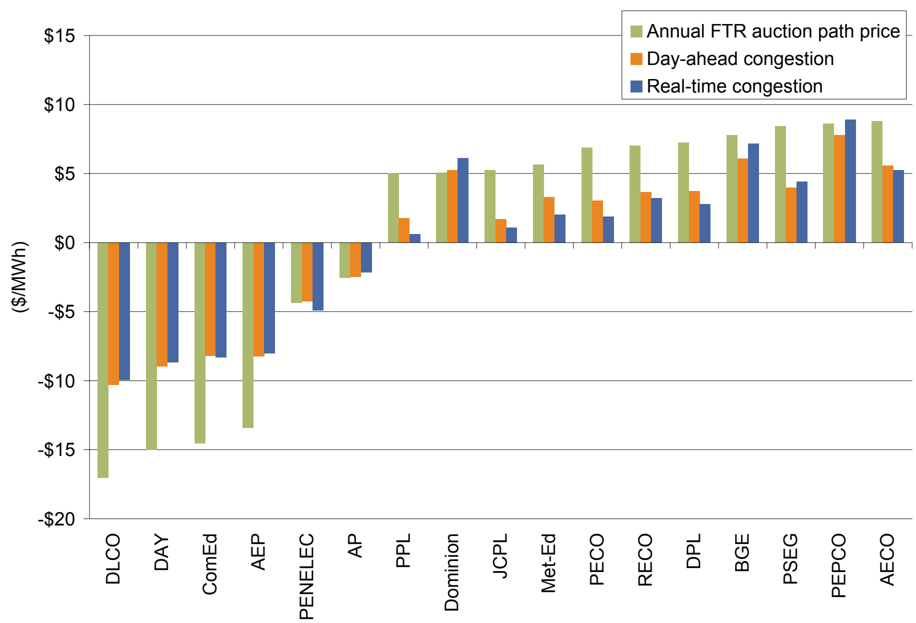
49 *Front Royal, Town of,* Answer of PJM Interconnection, L.L.C. to complaint, Docket No. EL06-94-000 (August 23, 2006).

50 117 FERC ¶ 61,219 (2006).

51 *Front Royal, Town of,* Request for Rehearing of the Borough of Chambersburg, PA, and the Town of Front Royal, VA, Docket No. EL06-94-000 (December 21, 2006).

in this way, were positive and were lower than the positive price of FTRs for most control zones that are located east of the Western Hub while congestion costs were negative and were less negative than the negative price of FTRs for control zones that are located west of that hub.

Figure 8-11 Annual FTR auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2006 to 2007 through December 31, 2006



Effectiveness of ARRs as a Hedge against Congestion

One measure of the effectiveness of ARRs as a hedge against congestion is a comparison of the revenue received by the holders of ARRs and the congestion across the corresponding paths. The revenue which serves as a hedge for ARR holders comes from the FTR auctions while the hedge for FTR holders is provided by the congestion payments derived directly from the Day-Ahead and Balancing Energy Market. Thus, ARRs are an indirect hedge against actual congestion in both the Day-Ahead and Balancing Energy Market.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead and Balancing Energy Market is presented by control zone in Table 8-17. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[52] Total Revenue equals the ARR credits and the FTR credits from ARRs which are self-scheduled as FTRs. The ARR credits do not include the credits for the portion of any ARR that was self-scheduled as an FTR since ARR holders purchase self-scheduled FTRs in the Annual FTR Auction and that revenue is then paid

52 Aggregates are separated into their individual bus components and each bus is assigned to a control zone. Aggregates that are external sinks are included in the PJM Control Zone.

back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (does not include any self-scheduled FTR MW) and the sink-minus-source price difference for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and, depending on market conditions, may be less than the target allocation. The FTR payout ratio equals the percentage of the target allocation that FTR holders actually receive as credits. The FTR payout ratio was 91 percent of the target allocation for the 2005 to 2006 planning period.

The "Congestion" column shows the amount of congestion in each control zone from the Day-Ahead and Balancing Energy Market and includes only the congestion costs incurred by the organizations that hold ARRs or self-scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Data shown are for the 2005 to 2006 planning period summed by ARR control zone sink. For example, the table shows that for the 2005 to 2006 planning period, ARRs allocated to the PSEG Control Zone received a total of $99.2 million in revenue which was the sum of $91.3 million in ARR credits and $7.9 million in credits for self-scheduled FTRs. This total revenue was $107.5 million less than the congestion costs of $206.7 million from the Day-Ahead and Balancing Energy Market incurred by organizations in the PSEG Control Zone that held ARRs or self-scheduled FTRs.

Table 8-17 ARR and self-scheduled FTR congestion hedging by control zone: Planning period 2005 to 2006

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference
AECO	$25,080,775	$7,555,906	$32,636,681	$139,421,972	($106,785,291)
AEP	$6,693,203	$0	$6,693,203	$448,522,559	($441,829,356)
AP	$33,933,744	$605,976,607	$639,910,351	$391,081,639	$248,828,712
BGE	$28,664,369	$15,833,167	$44,497,536	$99,551,176	($55,053,640)
ComEd	$14,507,397	($2,216,615)	$12,290,782	($40,725,173)	$53,015,955
DAY	$513,680	($906,367)	($392,687)	$31,002,175	($31,394,862)
DLCO	$4,928,691	$0	$4,928,691	($17,577,325)	$22,506,016
Dominion	$14,167,230	$1,991,239	$16,158,469	($3,726,484)	$19,884,953
DPL	$18,340,277	$2,740,951	$21,081,228	$169,195,102	($148,113,874)
JCPL	$22,708,342	$13,228,703	$35,937,045	$187,860,938	($151,923,893)
Met-Ed	$833,842	$38,521,619	$39,355,461	$96,411,629	($57,056,168)
PECO	$25,077,047	$83,967,680	$109,044,727	($30,485,404)	$139,530,131
PENELEC	$7,362,595	$20,554,603	$27,917,198	$133,872,573	($105,955,375)
PEPCO	$15,702,093	$9,208,222	$24,910,315	$421,462,182	($396,551,867)
PJM	$0	$599,826	$599,826	$53,153,698	($52,553,872)
PPL	$3,760,574	$50,948,653	$54,709,227	($61,590,973)	$116,300,200
PSEG	$91,334,187	$7,868,690	$99,202,877	$206,732,139	($107,529,262)
RECO	$1,103,171	$53,438	$1,156,609	$14,168,651	($13,012,042)
Total	$314,711,217	$855,926,322	$1,170,637,539	$2,238,331,074	($1,067,693,535)

During the 2005 to 2006 planning period, congestion costs associated with the 59,410 MW of allocated ARRs were $2,238.3 million. As Table 8-5 indicates, 32,631 MW of ARRs were converted into FTRs through the self-scheduling option, with 26,779 MW remaining as ARRs. The 26,779 MW of remaining ARRs provided $314.7 million of ARR credits, representing a hedge of 14.1 percent of the $2,238.3 million in congestion costs incurred, while the self-scheduled FTRs provided $855.9 million of revenue, hedging an additional 38.2 percent of congestion costs. Total congestion hedged by both was $1,170.6 million, or 52.3 percent. (See Table 8-17.) The effectiveness of ARRs as a hedge depends both on the ARR value which is a function of the FTR auction prices, on congestion patterns in the Day-Ahead and Real-Time Energy Market and on the FTR payout ratio.

Effectiveness of FTRs as a Hedge against Congestion

FTRs provide a direct hedge against congestion costs. Table 8-18 compares the total FTR credits and the total FTR auction revenues that sink in each control zone and the congestion costs in each control zone for the 2005 to 2006 planning period. FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable.[53] The "FTR Credits" column represents the total FTR target allocations for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly FTR Auctions and any FTRs that were self-scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 91 percent of the target allocation for the 2005 to 2006 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly FTR Auctions and any self-scheduled FTRs. The FTR hedge is the difference between the FTR credits and the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead and Balancing Energy Market in each control zone. The last column shows the difference between the FTR hedge and the congestion for each control zone.

All FTRs provided a hedge of $1,312.6 million against $2,203.9 million in congestion costs incurred.[54] This demonstrates that all FTRs provided a 59.6 percent hedge against congestion costs in PJM. For example, the table shows that for the 2005 to 2006 planning period, all FTRs sunk in the AP Control Zone received a total of $556 million in FTR credits while these FTRs cost $286.9 million in the FTR auctions. This gives a total FTR hedge of $269.1 million against $483.6 million in congestion costs from the Day-Ahead and Balancing Energy Market. This shows a deficit of $214.5 million in their total FTR hedge position versus the cost of congestion in the Day-Ahead and Balancing Energy Market. It would not be expected that the value of the FTR hedge calculated in this manner would cover all congestion costs as both ARRs and FTRs are available to hedge total congestion. That comparison is provided in Table 8-19.

53 Aggregates are separated into their individual bus components and each bus is assigned to a control zone. Aggregates that are external sinks are included in the PJM Control Zone.

54 The congestion costs in Table 8-18 do not equal the congestion costs in Table 8-17 because the congestion costs for organizations that did not hold ARRs had negative congestion costs that lowered the total congestion costs compared to those of just the ARR holders.

Table 8-18 FTR congestion hedging by control zone: Planning period 2005 to 2006

Control Zone	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference
AECO	$45,920,643	$42,074,184	$3,846,459	$85,668,131	($81,821,672)
AEP	$441,211,478	($15,723,909)	$456,935,387	$280,012,369	$176,923,018
AP	$555,983,348	$286,893,310	$269,090,038	$483,593,991	($214,503,953)
BGE	$99,105,743	$38,738,484	$60,367,259	$120,054,110	($59,686,851)
ComEd	($1,114,514)	$6,699,398	($7,813,912)	$211,614,849	($219,428,761)
DAY	($4,941,077)	($1,360,475)	($3,580,602)	$17,881,685	($21,462,287)
DLCO	($8,712,557)	($2,058,290)	($6,654,267)	$43,665,845	($50,320,112)
Dominion	$303,302,735	$2,301,529	$301,001,206	$235,274,973	$65,726,233
DPL	$31,778,673	$68,793,242	($37,014,569)	$122,049,540	($159,064,109)
JCPL	$45,242,267	$51,158,477	($5,916,210)	$157,969,491	($163,885,701)
Met-Ed	$67,782,208	$40,371,152	$27,411,056	$27,068,919	$342,137
PECO	$115,947,529	$118,291,396	($2,343,867)	($68,894,565)	$66,550,698
PENELEC	$32,497,904	$3,022,325	$29,475,579	$132,652,047	($103,176,468)
PEPCO	$233,047,816	$69,380,488	$163,667,328	$232,932,481	($69,265,153)
PJM	$23,394,836	$1,702,640	$21,692,196	($1,896,592)	$23,588,788
PPL	$58,023,715	$50,806,886	$7,216,829	($76,131,684)	$83,348,513
PSEG	$169,053,611	$133,431,947	$35,621,664	$182,384,671	($146,763,007)
RECO	$2,949,755	$3,392,076	($442,321)	$17,996,930	($18,439,251)
Total	$2,210,474,113	$897,914,860	$1,312,559,253	$2,203,897,191	($891,337,938)

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-19 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead and Balancing Energy Market for the 2005 to 2006 planning period. This compares the total hedge provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable.[55] ARR credits are calculated as the product of the ARR MW and the sink-minus-source price difference for the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly FTR Auctions and any FTRs that were self-scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 91 percent of the target allocation for the 2005 to 2006 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly FTR Auctions and any ARRs that were self-scheduled as FTRs. ARR holders that self-schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR hedge is the sum of the ARR credits and the FTR credits minus the FTR auction

55 Aggregates are separated into their individual bus components and each bus is assigned to a control zone. Aggregates that are external sinks are included in the PJM Control Zone.

revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead and Balancing Energy Market in each control zone. The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

The results indicate that the value of ARRs and FTRs together were less than total congestion costs by about $21 million, or slightly less than one percent. During the 2005 to 2006 planning period, the 59,410 MW of cleared ARRs produced $870.3 million of ARR credits while the total of all FTR credits was $2,210.5 million. Together, the ARR credits and FTR credits provided $3,080.8 million in total ARR and FTR revenue. When calculating the total ARR and FTR hedge, the cost to obtain the FTRs must be subtracted from the total ARR and FTR revenue. This cost is the total sum of the FTR auction revenues which was $897.9 million for the 2005 to 2006 planning period. The total ARR and FTR hedge equals $2,182.9 million, a hedge of 99 percent of $2,203.9 million of congestion in the Day-Ahead and Balancing Energy Market.[56] For example, the table shows that all ARRs and FTRs that sink in the PPL Control Zone received $55.4 million in ARR credits and $58 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $50.8 million, the total ARR and FTR hedge was $62.6 million. Their total hedge was $138.7 million higher than the -$76.1 million of congestion in the Day-Ahead and Balancing Energy Market.

Table 8-19 ARR and FTR congestion hedging by control zone: Planning period 2005 to 2006

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference
AECO	$31,276,088	$45,920,643	$42,074,184	$35,122,547	$85,668,131	($50,545,584)
AEP	$16,585,860	$441,211,478	($15,723,909)	$473,521,247	$280,012,369	$193,508,878
AP	$361,469,998	$555,983,348	$286,893,310	$630,560,036	$483,593,991	$146,966,045
BGE	$34,661,561	$99,105,743	$38,738,484	$95,028,820	$120,054,110	($25,025,290)
ComEd	$18,303,358	($1,114,514)	$6,699,398	$10,489,446	$211,614,849	($201,125,403)
DAY	$530,510	($4,941,077)	($1,360,475)	($3,050,092)	$17,881,685	($20,931,777)
DLCO	$4,975,801	($8,712,557)	($2,058,290)	($1,678,466)	$43,665,845	($45,344,311)
Dominion	$15,272,576	$303,302,735	$2,301,529	$316,273,782	$235,274,973	$80,998,809
DPL	$21,623,521	$31,778,673	$68,793,242	($15,391,048)	$122,049,540	($137,440,588)
JCPL	$37,324,433	$45,242,267	$51,158,477	$31,408,223	$157,969,491	($126,561,268)
Met-Ed	$26,625,842	$67,782,208	$40,371,152	$54,036,898	$27,068,919	$26,967,979
PECO	$106,838,594	$115,947,529	$118,291,396	$104,494,727	($68,894,565)	$173,389,292
PENELEC	$20,595,178	$32,497,904	$3,022,325	$50,070,757	$132,652,047	($82,581,290)
PEPCO	$18,332,199	$233,047,816	$69,380,488	$181,999,527	$232,932,481	($50,932,954)
PJM	$2,106,635	$23,394,836	$1,702,640	$23,798,831	($1,896,592)	$25,695,423
PPL	$55,370,821	$58,023,715	$50,806,886	$62,587,650	($76,131,684)	$138,719,334
PSEG	$97,257,083	$169,053,611	$133,431,947	$132,878,747	$182,384,671	($49,505,924)
RECO	$1,163,157	$2,949,755	$3,392,076	$720,836	$17,996,930	($17,276,094)
Total	$870,313,215	$2,210,474,113	$897,914,860	$2,182,872,468	$2,203,897,191	($21,024,723)

56 The congestion costs in Table 8-19 do not equal the congestion costs in Table 8-17 because the congestion costs for organizations that did not hold ARRs had negative congestion costs that lowered the total congestion costs compared to those of just the ARR holders.

Table 8-20 shows that for the 2005 to 2006 planning period, the total ARR and FTR hedge was $21 million less than the total congestion within PJM. All ARRs and FTRs hedged approximately 99 percent of the total congestion costs in the Day-Ahead and Balancing Energy Market within PJM.[57] For the first seven months (June through December 2006) of the 2006 to 2007 planning period, all ARRs and FTRs hedged 98.4 percent of the total congestion costs within PJM. The total ARR and FTR hedge position was less than the cost of congestion by $16.8 million.

Table 8-20 ARR and FTR congestion hedging: Planning periods 2005 to 2006 and 2006 to 2007[58]

Planning Period	ARR Credits	FTR Payout Ratio	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference
2005/2006	$870,313,215	91%	$2,210,474,113	$897,914,860	$2,182,872,468	$2,203,897,191	($21,024,723)
2006/2007*	$1,404,646,982	100%	$1,087,193,025	$1,431,111,828	$1,060,728,179	$1,077,545,881	($16,817,702)
* Shows 7 months ending 31-Dec-06							

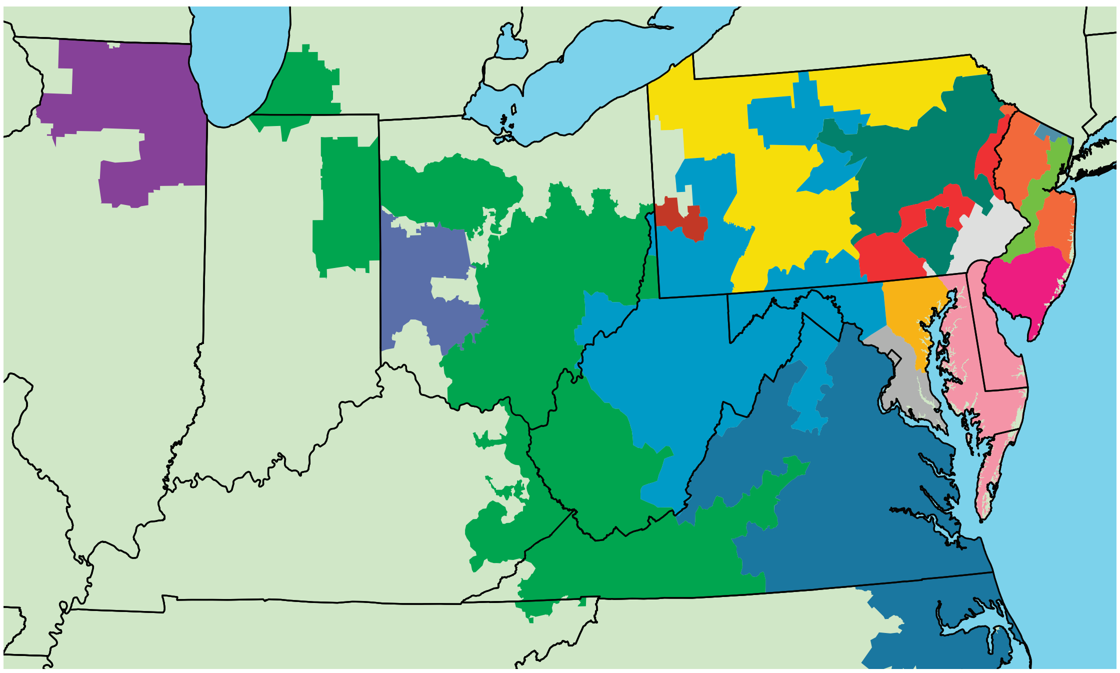
57 The congestion costs for the 2005 to 2006 planning period in Table 8-20 do not equal the congestion costs in Table 8-17 because the congestion costs for organizations that did not hold ARRs had negative congestion costs that lowered the total congestion costs compared to those of just the ARR holders.

58 The FTR credits do not include after-the-fact adjustments.

APPENDIX A – PJM GEOGRAPHY

During 2006, the PJM geographic footprint encompassed 17 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia

Figure A-1 PJM's footprint and its zones



Legend

- Allegheny Power Company (AP)
- American Electric Power Co., Inc. (AEP)
- Atlantic Electric Company (AECO)
- Baltimore Gas and Electric Company (BGE)
- The Commonwealth Edison Company (ComEd)
- Dayton Power and Light Company (DAY)
- Delmarva Power and Light (DPL)
- Dominion
- Duquesne Light (DLCO)
- Jersey Central Power and Light Company (JCPL)
- Metropolitan Edison Company (Met-Ed)
- PECO Energy (PECO)
- PPL Electric Utilities (PPL)
- Pennsylvania Electric Company (PENELEC)
- Potomac Electric Power Company (PEPCO)
- Public Service Electric and Gas Company (PSEG)
- Rockland Electric Company (RECO)

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.

During calendar years 2004 and 2005, PJM integrated five control zones. In the 2004 State of the Market Report the calendar year was divided into three phases, corresponding to market integration dates.[1] In the 2005 State of the Market Report the calendar year was divided into two phases, also corresponding to market integration dates:[2]

- **Phase 1 (2004).** The four-month period from January 1 through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[3] and the Allegheny Power Company (AP) Control Zone.[4]

- **Phase 2 (2004).** The five-month period from May 1 through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the Commonwealth Edison Company Control Area (ComEd).[5]

- **Phase 3 (2004).** The three-month period from October 1 through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- **Phase 4 (2005).** The four-month period from January 1 through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1 through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

1 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3.

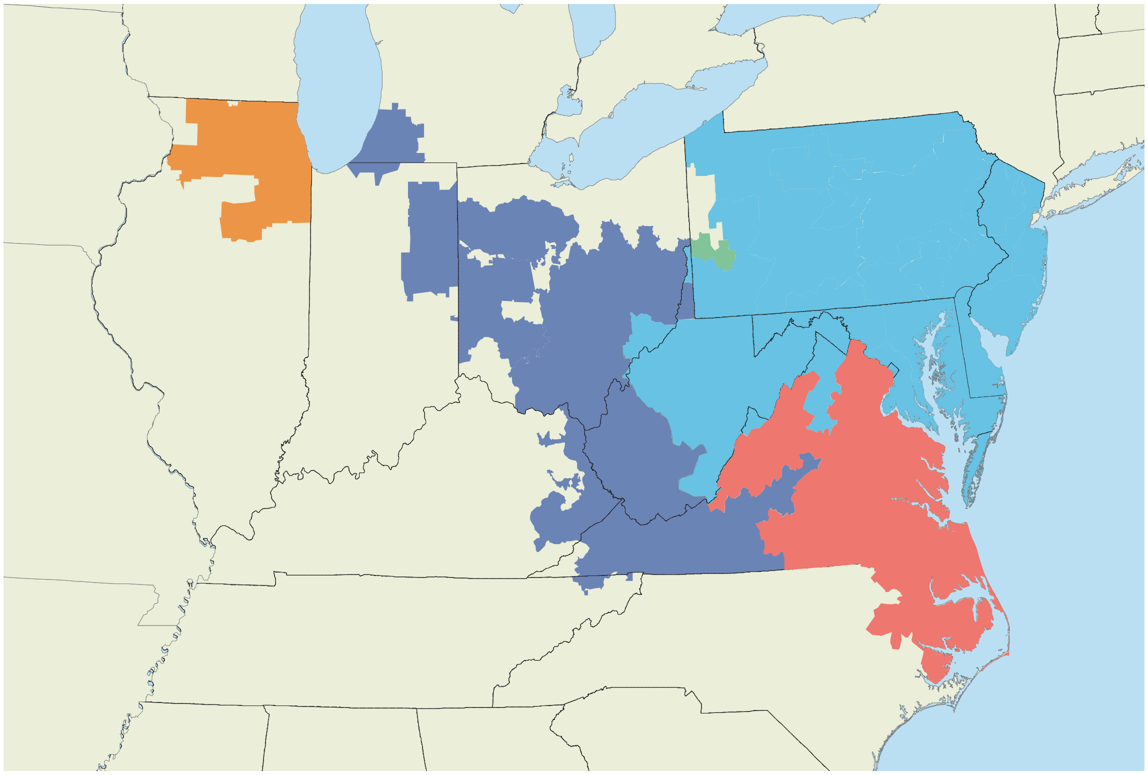
2 See the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

3 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, PEPCO, PPL, PSEG and RECO Control Zones.

4 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

5 During the five-month period May 1, 2004, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

Figure A-2 PJM integration phases

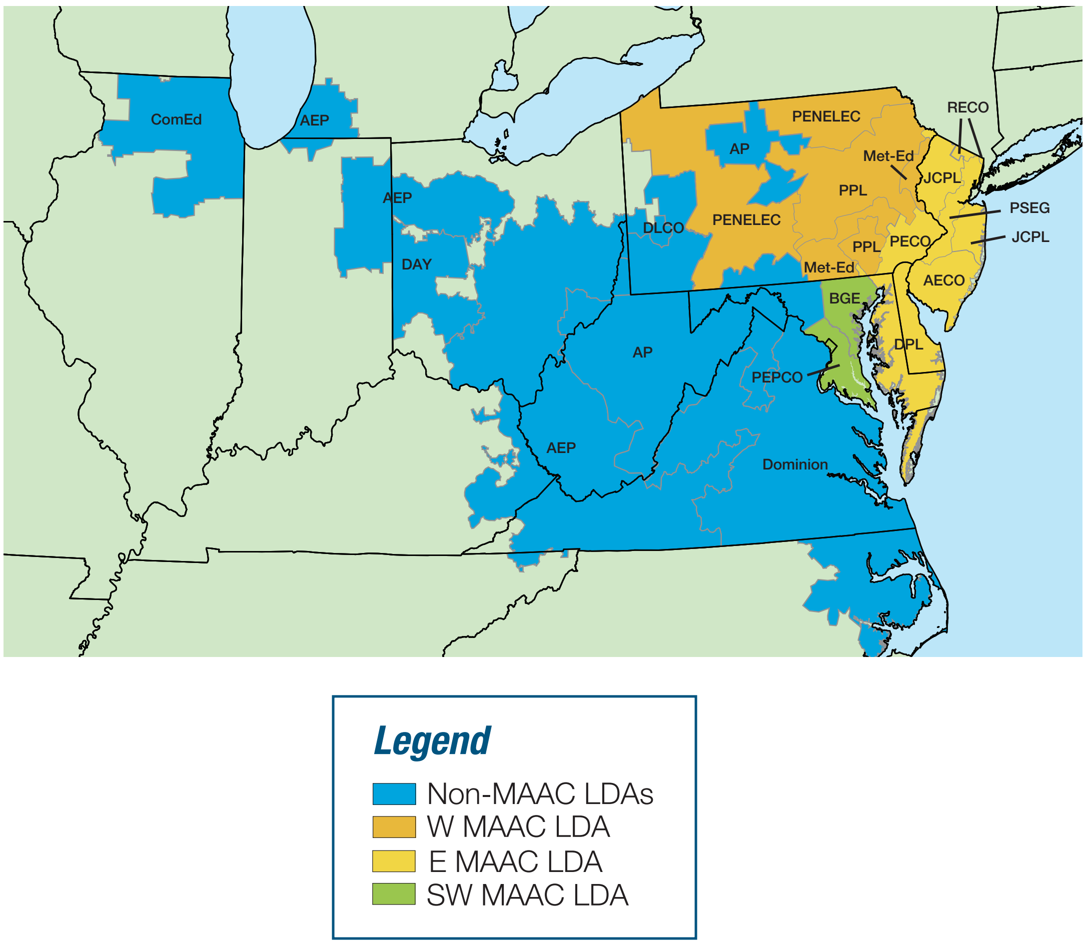


Legend

- Phase 1
- Phase 2
- Phase 3
- Phase 4
- Phase 5

A locational deliverability area (LDA) is a geographic area within the PJM Control Area that has limited transmission capability to import capacity to satisfy such area's reliability requirements, as determined by PJM in connection with its preparation of the Regional Transmission Expansion Plan (RTEP) and as specified in Schedule 10.1 of the PJM "Reliability Assurance Agreement with Load-Serving Entities." [6]

Figure A-3 PJM locational deliverability areas



6 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Definition 2.38" (Issued September 29, 2006, with an effective date of June 1, 2007).

APPENDIX B – PJM MARKET MILESTONES

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction

APPENDIX C – ENERGY MARKET

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM load by hour, for the calendar years 2002 to 2006. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the load was between 0 MW and 20,000 MW and then within a given 5,000-MW load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone during 2002, the ComEd, AEP and DAY Control Zones during 2004 and the DLCO and Dominion Control Zones during 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth. [1]

For the year 2002, the most frequently occurring load interval was 30,000 MW to 35,000 MW at 26.5 percent of the hours, with the load interval 35,000 MW to 40,000 MW nearly as frequent at 25.1 percent of the hours. In 2003, the most frequently occurring load interval was 35,000 MW to 40,000 MW at 31.3 percent of the hours, while load was less than 35,000 MW for 36.3 percent of the hours.

The frequency distribution of load in 2004 reflects the integrations of the ComEd, AEP and DAY Control Zones. The most frequently occurring load interval was 35,000 MW to 40,000 MW at 15.8 percent of the hours. The next most frequently occurring interval was 40,000 MW to 45,000 MW at 14.9 percent of the hours. Load was less than 60,000 MW for 74.8 percent of the time, less than 70,000 MW for 92.8 percent of the time and less than 90,000 MW for all but nine hours.

The frequency distribution of load in 2005 reflects the phased integrations of the DLCO and Dominion Control Zones. The most frequently occurring load interval was 75,000 MW to 80,000 MW at 16.1 percent of the hours. The next most frequently occurring interval was 65,000 MW to 70,000 MW at 13.4 percent of the hours. Load was less than 85,000 MW for 72.9 percent of the time, less than 100,000 MW for 88.2 percent of the time and less than 130,000 MW for all but 22 hours.

For the year 2006, the most frequently occurring load interval was 75,000 MW to 80,000 MW at 17.1 percent of the hours. The next most frequently occurring interval was 80,000 MW to 85,000 MW at 15.3 percent of the hours. Load was less than 85,000 MW for 70.9 percent of the hours, less than 100,000 MW for 91.5 percent of the hours and less than 130,000 MW for all but 50 hours.

The peak demand for the year 2006 was 144,644 MW on August 2, 2006. It was 8.1 percent higher than the peak demand for the year 2005 of 133,763 MW on July 26, 2005. [2]

1 See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

2 Peak-load data for 2006 are from PJM's eMTR data.

Table C-1 Frequency distribution of hourly PJM real-time load: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
Load (1,000 MW)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
20 and Less	4	0.05%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	398	4.59%	100	1.14%	15	0.17%	0	0.00%	0	0.00%
25 to 30	1,749	24.55%	1,193	14.76%	280	3.36%	0	0.00%	0	0.00%
30 to 35	2,320	51.04%	1,887	36.30%	697	11.29%	0	0.00%	0	0.00%
35 to 40	2,199	76.14%	2,738	67.56%	1,387	27.08%	0	0.00%	0	0.00%
40 to 45	1,037	87.98%	1,666	86.58%	1,311	42.01%	0	0.00%	0	0.00%
45 to 50	508	93.78%	796	95.66%	1,150	55.10%	71	0.81%	2	0.02%
50 to 55	252	96.66%	284	98.90%	847	64.74%	286	4.08%	129	1.50%
55 to 60	198	98.92%	84	99.86%	885	74.82%	636	11.34%	504	7.25%
60 to 65	95	100.00%	12	100.00%	760	83.47%	843	20.96%	689	15.11%
65 to 70	0	100.00%	0	100.00%	821	92.82%	1,170	34.32%	967	26.15%
70 to 75	0	100.00%	0	100.00%	391	97.27%	1,089	46.75%	1,079	38.47%
75 to 80	0	100.00%	0	100.00%	157	99.06%	1,407	62.81%	1,501	55.61%
80 to 85	0	100.00%	0	100.00%	48	99.60%	887	72.93%	1,337	70.87%
85 to 90	0	100.00%	0	100.00%	26	99.90%	557	79.29%	943	81.63%
90 to 95	0	100.00%	0	100.00%	7	99.98%	453	84.46%	569	88.13%
95 to 100	0	100.00%	0	100.00%	2	100.00%	330	88.23%	295	91.50%
100 to 105	0	100.00%	0	100.00%	0	100.00%	308	91.75%	215	93.95%
105 to 110	0	100.00%	0	100.00%	0	100.00%	283	94.98%	161	95.79%
110 to 115	0	100.00%	0	100.00%	0	100.00%	169	96.91%	145	97.44%
115 to 120	0	100.00%	0	100.00%	0	100.00%	113	98.20%	102	98.61%
120 to 125	0	100.00%	0	100.00%	0	100.00%	93	99.26%	45	99.12%
125 to 130	0	100.00%	0	100.00%	0	100.00%	43	99.75%	27	99.43%
130 to 135	0	100.00%	0	100.00%	0	100.00%	22	100.00%	19	99.65%
135 to 140	0	100.00%	0	100.00%	0	100.00%	0	100.00%	19	99.86%
>140	0	100.00%	0	100.00%	0	100.00%	0	100.00%	12	100.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2006 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak load was about 23 percent higher than off-peak load in 2006. Average load during on-peak hours in 2006 was 1.3 percent higher than in 2005. Off-peak load in 2006 was 2.2 percent higher than in 2005. (See Table C-3.)

Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2006

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,268	32,344	1.28	24,728	31,081	1.26	4,091	4,388	1.07
1999	26,453	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,817	40,362	1.27	30,654	38,378	1.25	6,060	7,419	1.22
2003	33,595	41,755	1.24	32,971	40,802	1.24	5,546	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12

Table C-3 Multiyear change in load: Calendar years 1998 to 2006

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.6%)	4.3%	2.8%	(1.6%)	20.9%	9.9%	(8.4%)
2000	1.8%	1.6%	0.0%	2.1%	2.5%	0.0%	(9.7%)	(13.3%)	(4.1%)
2001	(0.4%)	1.5%	1.6%	0.5%	1.0%	0.8%	(5.4%)	16.0%	22.3%
2002	18.7%	17.7%	(0.8%)	16.0%	16.0%	0.0%	43.4%	52.9%	6.1%
2003	5.6%	3.5%	(2.4%)	7.6%	6.3%	(0.8%)	(8.5%)	(26.9%)	(19.7%)
2004	32.9%	34.2%	1.6%	30.5%	38.7%	5.6%	95.5%	132.2%	18.4%
2005	57.5%	55.6%	(1.6%)	58.2%	45.8%	(7.6%)	17.4%	21.0%	3.4%
2006	2.2%	1.3%	(0.8%)	3.3%	3.2%	0.0%	(10.9%)	(16.9%)	(6.7%)

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the PJM Market Monitoring Unit (MMU) examines three measures: nominal LMP, load-weighted LMP and fuel-cost-adjusted, load-weighted LMP. Nominal LMP measures the change in reported price. Load-weighted LMP measures the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Fuel-cost-adjusted, load-weighted LMP measures the change in reported price actually paid by load after accounting for the change in price that reflects shifts in underlying fuel prices.

Real-Time LMP

Frequency Distribution of Real-Time LMP

Table C-4 provides frequency distributions of real-time LMP, by hour, for the calendar years 2002 to 2006. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when LMP was within a given price interval, or for the cumulative column, within the interval plus all the lower price intervals.

During the period 2002 to 2003, LMP was most frequently in the $10-per-MWh to $20-per-MWh interval. In 2004, however, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 21.9 percent of the time and in the $20-per-MWh to $30-per-MWh interval nearly as frequently at 21.6 percent of the time. In 2005, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 20.5 percent of the time and in the $20-per-MWh to $30-per-MWh interval at 14.7 percent of the time. In 2005, LMP was less than $60 per MWh for 63.2 percent of the hours and less than $100 per MWh for 87.4 percent of the hours. LMP was $200 per MWh or greater for 35 hours (0.4 percent of the hours) in 2005. In 2006, LMP was in the $20-per-MWh to $30-per-MWh interval most frequently (22.4 percent of the time) and in the $30-per-MWh to $40-per-MWh interval next most frequently (21.0 percent of the hours). In 2006, LMP was less than $60 per MWh for 75.1 percent of the hours and less than $100 per MWh for 94.7 percent of the hours. LMP was $200 per MWh or greater for 35 hours (0.4 percent of the hours) in 2006.

Table C-4 Frequency distribution by hours of PJM real-time energy market LMP (Dollars per MWh): Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and Less	194	2.21%	241	2.75%	173	1.97%	142	1.62%	85	0.97%
$10 to $20	3,791	45.49%	2,083	26.53%	712	10.08%	259	4.58%	247	3.79%
$20 to $30	2,104	69.51%	1,957	48.87%	1,900	31.71%	1,290	19.30%	1,958	26.14%
$30 to $40	1,048	81.47%	1,102	61.45%	1,928	53.65%	1,793	39.77%	1,840	47.15%
$40 to $50	701	89.47%	1,043	73.36%	1,445	70.10%	1,172	53.15%	1,405	63.18%
$50 to $60	391	93.94%	812	82.63%	994	81.42%	877	63.16%	1,040	75.06%
$60 to $70	201	96.23%	532	88.70%	668	89.03%	730	71.50%	662	82.61%
$70 to $80	132	97.74%	380	93.04%	445	94.09%	568	77.98%	479	88.08%
$80 to $90	69	98.53%	255	95.95%	270	97.17%	453	83.15%	347	92.04%
$90 to $100	49	99.09%	152	97.68%	117	98.50%	374	87.42%	230	94.67%
$100 to $110	27	99.39%	75	98.54%	72	99.32%	297	90.81%	162	96.52%
$110 to $120	13	99.54%	52	99.13%	25	99.60%	208	93.18%	95	97.60%
$120 to $130	12	99.68%	28	99.45%	14	99.76%	159	95.00%	61	98.30%
$130 to $140	3	99.71%	23	99.71%	10	99.87%	110	96.26%	46	98.82%
$140 to $150	5	99.77%	14	99.87%	6	99.94%	94	97.33%	27	99.13%
$150 to $160	4	99.82%	5	99.93%	3	99.98%	53	97.93%	16	99.32%
$160 to $170	1	99.83%	1	99.94%	1	99.99%	57	98.58%	11	99.44%
$170 to $180	1	99.84%	1	99.95%	0	99.99%	51	99.17%	6	99.51%
$180 to $190	3	99.87%	2	99.98%	1	100.00%	22	99.42%	3	99.54%
$190 to $200	2	99.90%	1	99.99%	0	100.00%	16	99.60%	5	99.60%
$200 to $210	1	99.91%	0	99.99%	0	100.00%	12	99.74%	3	99.63%
$210 to $220	1	99.92%	1	100.00%	0	100.00%	10	99.85%	7	99.71%
$220 to $230	0	99.92%	0	100.00%	0	100.00%	5	99.91%	1	99.73%
$230 to $240	0	99.92%	0	100.00%	0	100.00%	1	99.92%	1	99.74%
$240 to $250	0	99.92%	0	100.00%	0	100.00%	1	99.93%	1	99.75%
$250 to $260	0	99.92%	0	100.00%	0	100.00%	3	99.97%	1	99.76%
$260 to $270	0	99.92%	0	100.00%	0	100.00%	2	99.99%	0	99.76%
$270 to $280	0	99.92%	0	100.00%	0	100.00%	0	99.99%	3	99.79%
$280 to $290	1	99.93%	0	100.00%	0	100.00%	1	100.00%	1	99.81%
$290 to $300	1	99.94%	0	100.00%	0	100.00%	0	100.00%	0	99.81%
$300 to $400	2	99.97%	0	100.00%	0	100.00%	0	100.00%	11	99.93%
$400 to $500	1	99.98%	0	100.00%	0	100.00%	0	100.00%	2	99.95%
$500 to $600	1	99.99%	0	100.00%	0	100.00%	0	100.00%	1	99.97%
$600 to $700	0	99.99%	0	100.00%	0	100.00%	0	100.00%	1	99.98%
> $700	1	100.00%	0	100.00%	0	100.00%	0	100.00%	2	100.00%

Off-Peak and On-Peak, Load-Weighted Real-Time LMP: 2005 to 2006

Table C-5 shows load-weighted, average LMP for 2005 and 2006 during off-peak and on-peak periods. In 2006, the on-peak, load-weighted LMP was 55 percent higher than the off-peak LMP, while in 2005, it was 64 percent greater. On-peak, load-weighted, average LMP in 2006 was 17.4 percent lower than in 2005. Off-peak, load-weighted LMP in 2006 was 12.9 percent lower than in 2005. The on-peak median LMP was lower in 2006 than in 2005 by 22.3 percent; off-peak median LMP was lower in 2006 than in 2005 by 9.4 percent. Dispersion in load-weighted LMP, as indicated by standard deviation, was 23.4 percent lower in 2006 than in 2005 during off-peak hours and was 17.1 percent higher during on-peak hours. Since the mean was above the median during on-peak and off-peak hours, both showed a positive skewness. The mean was, however, proportionately higher than the median in 2006 as compared to 2005 during both on-peak and off-peak periods (19.5 percent and 23.6 percent compared to 12.4 percent and 28.6 percent, respectively). The differences reflect larger positive skewness in the on-peak hours.

Table C-5 Off-peak and on-peak, load-weighted LMP (Dollars per MWh): Calendar years 2005 to 2006

	2005			2006			Difference 2005 to 2006		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$47.69	$78.04	1.64	$41.53	$64.46	1.55	(12.9%)	(17.4%)	(5.5%)
Median	$37.07	$69.42	1.87	$33.59	$53.96	1.61	(9.4%)	(22.3%)	(13.9%)
Standard Deviation	$31.38	$37.95	1.21	$24.03	$44.45	1.85	(23.4%)	17.1%	52.9%

Off-Peak and On-Peak, Fuel-Cost-Adjusted, Load-Weighted Real-Time LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up from 80 percent to 90 percent of marginal cost, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price will also increase.

The impact of fuel cost on LMP depends on the fuel burned by the marginal units. To account for differences in fuel cost between different time periods of interest, the fuel-cost-adjusted, load-weighted LMP is used to compare load-weighted LMPs on a common fuel-cost basis.

Table C-6 and Table C-7 show the load-weighted, average real-time LMP and the fuel-cost-adjusted, load-weighted, average real-time LMP for 2006 for on-peak and off-peak hours. During on-peak hours the fuel-cost-adjusted, load-weighted, real-time LMP in 2006 decreased by 7.3 percent over the load-weighted, real-time LMP in 2005. The fuel-cost-adjusted, load-weighted, real-time LMP in 2006 decreased by 3.4 percent in the off-peak hours compared to the load-weighted, real-time LMP in 2005.

Table C-6 On-peak PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2005	2006
Load-Weighted LMP	$78.04	$64.46
Fuel-Cost-Adjusted, Load-Weighted LMP	NA	$72.37
Year-over-Year Comparison	NA	(7.3%)

Table C-7 Off-peak PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2005	2006
Load-Weighted LMP	$47.69	$41.53
Fuel-Cost-Adjusted, Load-Weighted LMP	NA	$46.05
Year-over-Year Comparison	NA	(3.4%)

Load-Weighted, Real-Time LMP during Constrained Hours

Table C-8 shows that the load-weighted, average LMP during constrained hours was 12.9 percent lower in 2006 than it had been in 2005.[3] The median, load-weighted LMP during constrained hours was 13.0 percent lower in 2006 than in 2005 and the standard deviation was 3.6 percent higher in 2006 than in 2005.

Table C-8 Load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2005 to 2006

	2005	2006	Difference
Average	$66.18	$57.62	(12.9%)
Median	$55.56	$48.34	(13.0%)
Standard Deviation	$38.61	$40.01	3.6%

Table C-9 provides a comparison of load-weighted, average LMP during constrained and unconstrained hours for 2005 and 2006. In 2006, load-weighted, average LMP during constrained hours was 61.1 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2005 was 53.8 percent.

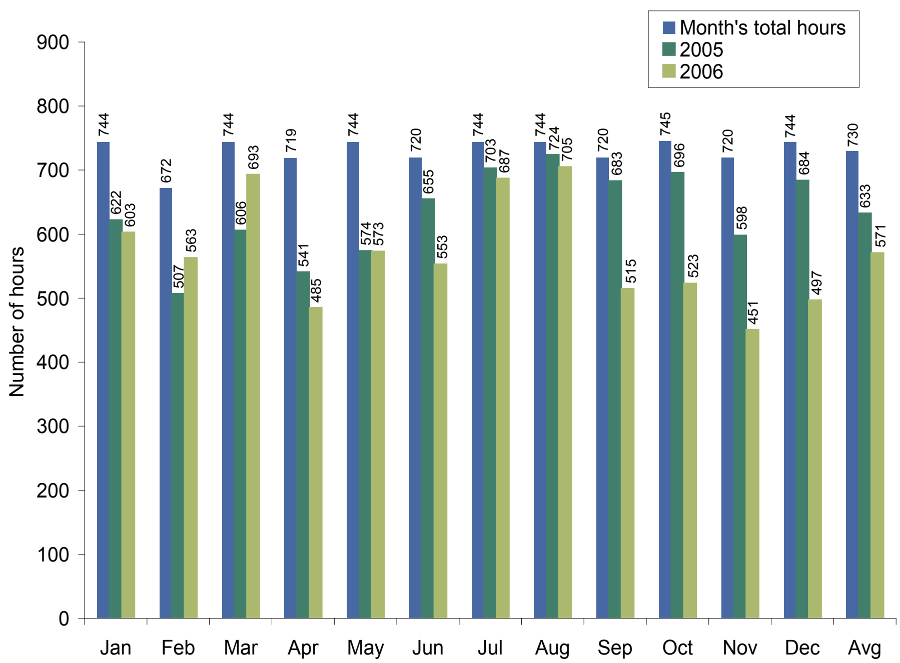
3 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. In the *2006 State of the Market Report*, in order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In the *2005 State of the Market Report*, an hour was considered constrained if one or more facilities were constrained for four or more of the 12 five-minute intervals in that hour. In the *2004 State of the Market Report*, this appendix defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

Table C-9 Load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2005 to 2006

	2005			2006		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$43.03	$66.18	53.8%	$35.76	$57.62	61.1%
Median	$36.30	$55.56	53.1%	$29.67	$48.34	62.9%
Standard Deviation	$26.13	$38.61	47.8%	$18.43	$40.01	117.1%

Figure C-1 shows the number of hours and the number of constrained hours during each month in 2005 and 2006. There were 7,593 constrained hours in 2005 and 6,848 in 2006, a decrease of approximately 9.8 percent. Figure C-1 also shows that the average number of constrained hours per month was slightly higher in 2005 than in 2006, with 633 per month in 2005 versus 571 per month in 2006.

Figure C-1 PJM real-time constrained hours: Calendar years 2005 to 2006



Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2006 were slightly higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of average, system LMP distribution for 2006 can be seen in Table C-4 and Table C-10. Together they show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market, the most frequently occurring price interval was the $20-per-MWh to $30-per-MWh interval with 22.4 percent of the hours in 2006. (See Table

C-4.) The most frequently occurring price interval in the PJM Day-Ahead Energy Market was the $40-per-MWh to $50-per-MWh interval with 21.6 percent of the hours in 2006. (See Table C-10.) In the Real-Time Energy Market, prices were above $200 per MWh for 35 hours (0.4 percent of the hours), reaching a high for the year of $763.80 per MWh on August 1, 2006, during the hour ending 1800 EPT. In the Day-Ahead Energy Market, prices were above $200 per MWh for 25 hours (0.3 percent of the hours) and reached a high for the year of $333.91 per MWh on August 3, 2006, during the hour ending 1700 EPT.

Table C-10 Frequency distribution by hours of PJM day-ahead LMP (Dollars per MWh): Calendar year 2002 to 2006

	2002		2003		2004		2005		2006	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and Less	128	1.46%	131	1.50%	59	0.67%	47	0.54%	11	0.13%
$10 to $20	3,177	37.73%	1,530	18.96%	715	8.81%	162	2.39%	147	1.80%
$20 to $30	2,564	67.00%	1,846	40.03%	1,684	27.98%	1,022	14.05%	1,610	20.18%
$30 to $40	1,470	83.78%	1,635	58.70%	1,848	49.02%	1,753	34.06%	1,747	40.13%
$40 to $50	690	91.66%	1,384	74.50%	1,946	71.17%	1,382	49.84%	1,890	61.70%
$50 to $60	329	95.41%	1,004	85.96%	1,357	86.62%	1,102	62.42%	1,364	77.27%
$60 to $70	146	97.08%	554	92.28%	728	94.91%	812	71.69%	905	87.60%
$70 to $80	92	98.13%	318	95.91%	278	98.08%	686	79.52%	524	93.58%
$80 to $90	50	98.70%	157	97.71%	110	99.33%	524	85.50%	237	96.29%
$90 to $100	29	99.03%	95	98.79%	42	99.81%	388	89.93%	145	97.95%
$100 to $110	24	99.30%	41	99.26%	11	99.93%	263	92.93%	65	98.69%
$110 to $120	16	99.49%	21	99.50%	4	99.98%	207	95.30%	38	99.12%
$120 to $130	7	99.57%	22	99.75%	2	100.00%	151	97.02%	11	99.25%
$130 to $140	11	99.69%	7	99.83%	0	100.00%	102	98.18%	8	99.34%
$140 to $150	7	99.77%	5	99.89%	0	100.00%	64	98.92%	8	99.43%
$150 to $160	8	99.86%	10	100.00%	0	100.00%	46	99.44%	7	99.51%
$160 to $170	1	99.87%	0	100.00%	0	100.00%	27	99.75%	6	99.58%
$170 to $180	2	99.90%	0	100.00%	0	100.00%	11	99.87%	6	99.65%
$180 to $190	4	99.94%	0	100.00%	0	100.00%	8	99.97%	3	99.68%
$190 to $200	0	99.94%	0	100.00%	0	100.00%	1	99.98%	3	99.71%
$200 to $210	4	99.99%	0	100.00%	0	100.00%	2	100.00%	3	99.75%
$210 to $220	1	100.00%	0	100.00%	0	100.00%	0	100.00%	3	99.78%
$220 to $230	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.79%
$230 to $240	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	99.83%
$240 to $250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	2	99.85%
$250 to $260	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.86%
$260 to $270	0	100.00%	0	100.00%	0	100.00%	0	100.00%	2	99.89%
$270 to $280	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.90%
$280 to $290	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.91%
$290 to $300	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.92%
> $300	0	100.00%	0	100.00%	0	100.00%	0	100.00%	7	100.00%

Off-Peak and On-Peak, Day-Ahead and Real-Time LMP

Table C-11 shows average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Market during calendar year 2006. Day-ahead and real-time, on-peak average LMPs were 54 percent and 56 percent higher, respectively, than the corresponding off-peak average LMP. Since the mean was above the median in these markets, both showed a positive skewness. The mean was, however, proportionately higher than the median in the Real-Time Energy Market as compared to the Day-Ahead Energy Market during both on-peak and off-peak periods (17 percent and 23 percent compared to 9 percent and 12 percent, respectively). The differences reflect larger positive skewness in the Real-Time Energy Market.

Figure C-2 and Figure C-3 show the difference between real-time and day-ahead LMP during calendar year 2006 during the on-peak and off-peak hours, respectively. The difference between real-time and day-ahead average LMP during on-peak hours was $1.76 per MWh. (Day-ahead LMP was lower than real-time LMP.) During the off-peak hours, the difference between real-time and day-ahead average LMP was $0.67 per MWh. (Day-ahead LMP was lower than real-time LMP.)

Table C-11 Off-peak and on-peak hourly LMP (Dollars per MWh): Calendar year 2006

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$38.45	$59.25	1.54	$39.12	$61.01	1.56	1.7%	3.0%	1.3%
Median	$34.40	$54.41	1.58	$31.84	$52.28	1.64	(7.4%)	(3.9%)	3.8%
Standard Deviation	$16.06	$25.54	1.59	$22.58	$38.21	1.69	40.6%	49.6%	6.3%

Figure C-2 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2006

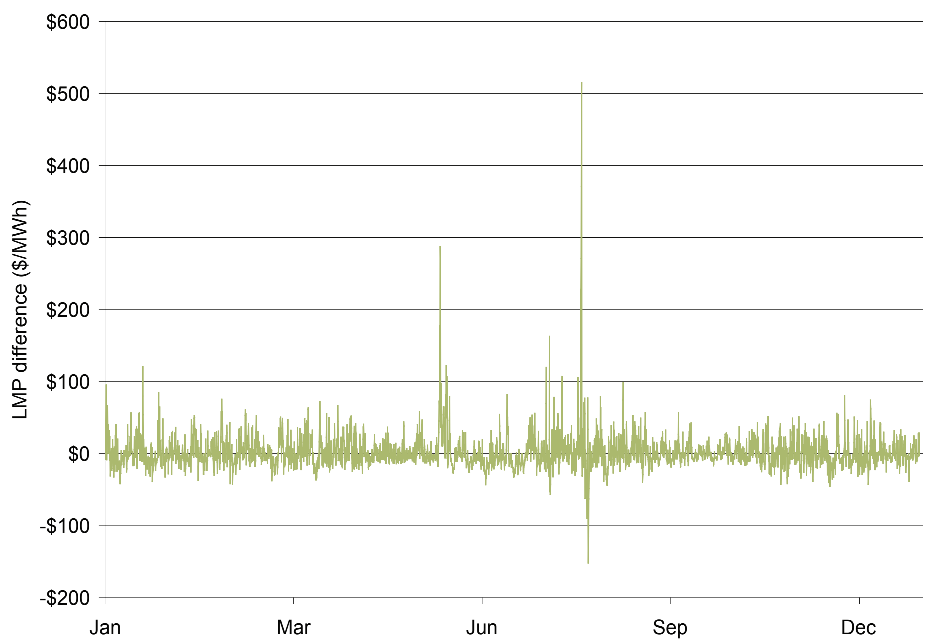
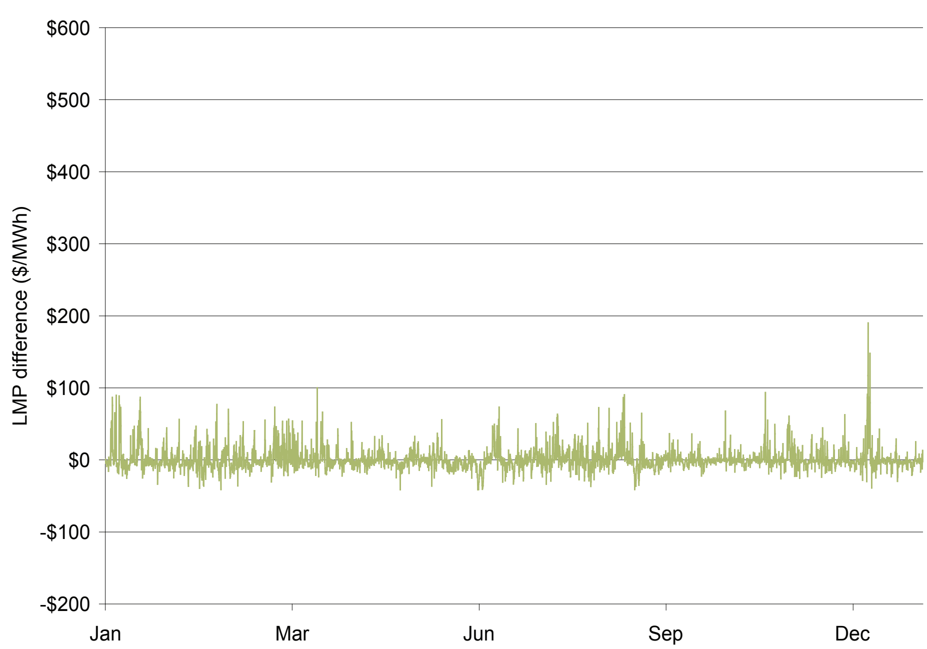


Figure C-3 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2006



Off-Peak and On-Peak Zonal Day-Ahead and Real-Time LMP

Table C-12 and Table C-13 show the average on-peak and off-peak LMP for each zone in the Day-Ahead and Real-Time Energy Market during calendar year 2006. The zone with the maximum difference between real-time and day-ahead on-peak LMP was the PEPCO Control Zone with an on-peak, day-ahead zonal LMP $2.53 lower than its on-peak, real-time zonal LMP. DPL Control Zone had the smallest difference with its on-peak, real-time zonal LMP $0.10 lower than its on-peak, day-ahead zonal LMP. (See Table C-12.) The PEPCO and Dominion Control Zones had the largest difference between real-time and day-ahead off-peak zonal LMP, with day-ahead LMP $1.68 lower than real-time LMP. The zone with the smallest difference between real-time and day-ahead off-peak zonal LMP was DAY Control Zone with day-ahead LMP $0.10 lower than real-time LMP. (See Table C-13.)

Table C-12 Zonal on-peak hourly LMP (Dollars per MWh): Calendar year 2006

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$68.16	$69.42	($1.26)	(1.82%)
AEP	$51.91	$53.55	($1.64)	(3.06%)
AP	$58.32	$60.06	($1.74)	(2.90%)
BGE	$67.26	$69.58	($2.32)	(3.33%)
ComEd	$51.73	$53.17	($1.44)	(2.71%)
DAY	$50.85	$52.64	($1.79)	(3.40%)
DLCO	$48.72	$50.86	($2.14)	(4.21%)
Dominion	$64.95	$67.00	($2.05)	(3.06%)
DPL	$65.31	$65.21	$0.10	0.15%
JCPL	$63.44	$64.30	($0.86)	(1.34%)
Met-Ed	$65.31	$64.92	$0.39	0.60%
PECO	$64.60	$64.10	$0.50	0.78%
PENELEC	$56.77	$57.83	($1.06)	(1.83%)
PEPCO	$68.59	$71.12	($2.53)	(3.56%)
PPL	$63.54	$63.34	$0.20	0.32%
PSEG	$66.33	$68.09	($1.76)	(2.58%)
RECO	$66.14	$67.19	($1.05)	(1.56%)

Table C-13 Zonal off-peak hourly LMP (Dollars per MWh): Calendar year 2006

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$42.83	$43.51	($0.68)	(1.56%)
AEP	$32.29	$32.46	($0.17)	(0.52%)
AP	$37.82	$38.88	($1.06)	(2.73%)
BGE	$45.35	$46.87	($1.52)	(3.24%)
ComEd	$31.80	$31.43	$0.37	1.18%
DAY	$31.22	$31.32	($0.10)	(0.32%)
DLCO	$30.52	$29.37	$1.15	3.92%
Dominion	$45.62	$47.30	($1.68)	(3.55%)
DPL	$42.32	$42.61	($0.29)	(0.68%)
JCPL	$40.67	$40.97	($0.30)	(0.73%)
Met-Ed	$41.67	$42.05	($0.38)	(0.90%)
PECO	$41.96	$42.28	($0.32)	(0.76%)
PENELEC	$36.84	$36.95	($0.11)	(0.30%)
PEPCO	$46.55	$48.23	($1.68)	(3.48%)
PPL	$41.05	$41.29	($0.24)	(0.58%)
PSEG	$42.74	$42.88	($0.14)	(0.33%)
RECO	$42.81	$42.36	$0.45	1.06%

Day-Ahead and Real-Time LMP during Constrained Hours

Figure C-4 shows the number of constrained hours in each month for the Day-Ahead and Real-Time Energy Market, the total number of hours and the total number of constrained hours in each month for 2006. Overall, there were 6,848 constrained hours in the Real-Time Energy Market and 8,626 constrained hours in the Day-Ahead Energy Market. Figure C-4 shows that in every month of calendar year 2006 the number of constrained hours in the Day-Ahead Energy Market exceeded those in the Real-Time Energy Market. Over the year, the Day-Ahead Energy Market had 26.0 percent more constrained hours than the Real-Time Energy Market.

Figure C-4 Day-ahead and real-time, market-constrained hours: Calendar year 2006

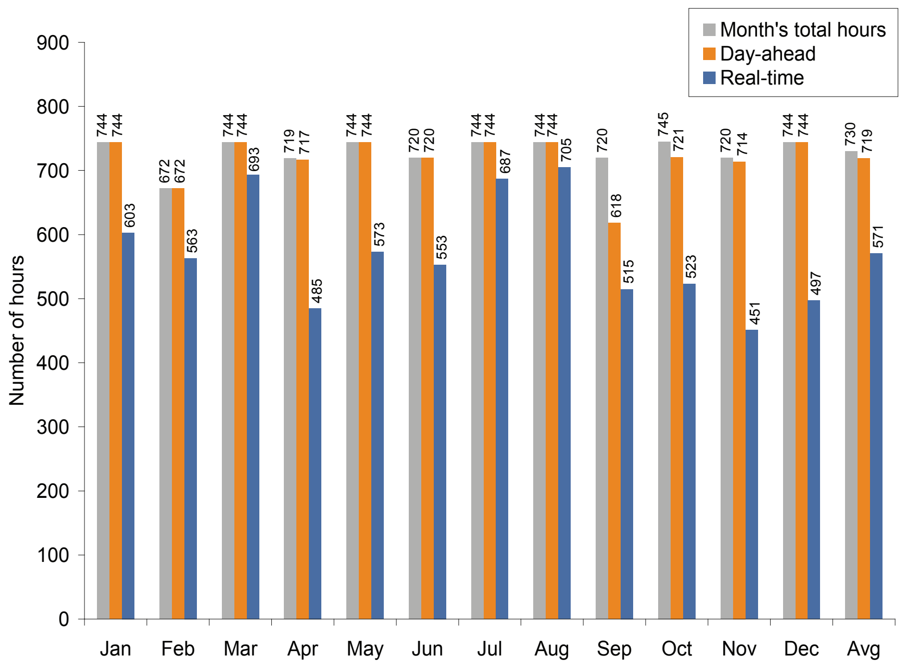


Table C-14 shows average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Market. In the Day-Ahead Energy Market, average LMP during constrained hours was 52.5 percent higher than average LMP during unconstrained hours. In the Real-Time Energy Market, average LMP during constrained hours was 57.1 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 10.7 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 7.4 percent higher in the Real-Time Market than in the Day-Ahead Market.

Table C-14 LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2006

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$31.70	$48.35	52.5%	$34.06	$53.52	57.1%
Median	$30.84	$44.50	44.3%	$27.99	$45.41	62.2%
Standard Deviation	$9.59	$23.48	144.8%	$17.81	$34.60	94.3%

Taken together, the data show that average LMP in the Day-Ahead Energy Market during constrained hours was 0.5 percent higher than the overall average LMP for the Day-Ahead Energy Market, while average LMP during unconstrained hours was 34.1 percent lower.[4] In the Real-Time Energy Market, average LMP during constrained hours was 8.6 percent higher than the overall average LMP for the Real-Time Energy Market, while average LMP during unconstrained hours was 30.9 percent lower.

Offer-Capped Units

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. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Market.

PJM has clear rules limiting the exercise of local market power.[5] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, 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.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that 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.

4 See *2006 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1" for a discussion of load and LMP.

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

Levels of offer capping have generally been low and stable over the last five years. Table C-15 through Table C-18 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Market. [6]

Table C-15 Average day-ahead, offer-capped units: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.6	0.1%	0.5	0.1%	0.4	0.1%	0.4	0.0%	0.1	0.0%
Feb	0.4	0.1%	0.7	0.1%	0.2	0.0%	0.4	0.0%	0.2	0.0%
Mar	0.1	0.0%	0.1	0.0%	0.2	0.0%	0.6	0.1%	0.7	0.1%
Apr	0.7	0.1%	0.6	0.1%	0.3	0.0%	0.4	0.0%	0.2	0.0%
May	0.2	0.0%	0.3	0.0%	0.6	0.1%	0.2	0.0%	0.1	0.0%
Jun	1.4	0.3%	0.7	0.1%	1.1	0.2%	0.4	0.0%	0.7	0.1%
Jul	1.9	0.4%	1.4	0.3%	2.6	0.4%	0.9	0.1%	4.1	0.4%
Aug	4.5	0.8%	2.1	0.4%	3.0	0.4%	1.1	0.1%	4.7	0.5%
Sep	1.9	0.4%	1.1	0.2%	3.1	0.4%	0.2	0.0%	0.6	0.1%
Oct	0.4	0.1%	0.9	0.2%	0.6	0.1%	0.3	0.0%	0.3	0.0%
Nov	0.6	0.1%	0.2	0.0%	0.5	0.1%	0.2	0.0%	0.3	0.0%
Dec	0.8	0.1%	0.1	0.0%	0.5	0.1%	0.7	0.1%	0.7	0.0%

Table C-16 Average day-ahead, offer-capped MW: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	40	0.1%	37	0.1%	51	0.1%	87	0.1%	4	0.0%
Feb	30	0.1%	27	0.1%	68	0.1%	75	0.1%	6	0.0%
Mar	6	0.0%	4	0.0%	48	0.1%	58	0.1%	51	0.1%
Apr	48	0.1%	38	0.1%	41	0.1%	34	0.0%	31	0.0%
May	14	0.0%	52	0.1%	52	0.1%	14	0.0%	22	0.0%
Jun	48	0.1%	69	0.2%	49	0.1%	28	0.0%	164	0.0%
Jul	77	0.1%	132	0.3%	243	0.4%	52	0.0%	518	0.5%
Aug	106	0.2%	148	0.3%	348	0.5%	63	0.1%	398	0.4%
Sep	78	0.2%	139	0.3%	221	0.4%	13	0.0%	51	0.1%
Oct	57	0.1%	100	0.2%	34	0.0%	16	0.0%	27	0.0%
Nov	30	0.1%	21	0.1%	28	0.0%	26	0.0%	15	0.0%
Dec	25	0.1%	25	0.1%	35	0.0%	48	0.0%	40	0.0%

6 Data quality improvements have caused values in these tables to vary slightly from previously published results.

Table C-17 Average real-time, offer-capped units: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	1.6	0.3%	1.5	0.3%	2.7	0.4%	2.5	0.3%	1.9	0.2%
Feb	0.8	0.2%	1.5	0.3%	0.7	0.1%	1.3	0.1%	2.1	0.2%
Mar	0.4	0.1%	0.5	0.1%	0.8	0.1%	1.4	0.2%	2.3	0.2%
Apr	1.0	0.2%	0.8	0.1%	1.8	0.3%	1.2	0.1%	1.5	0.2%
May	1.2	0.2%	1.6	0.3%	5.9	0.8%	0.8	0.1%	3.4	0.3%
Jun	3.1	0.6%	2.9	0.5%	3.9	0.5%	10.0	1.0%	2.5	0.3%
Jul	8.6	1.6%	3.3	0.6%	4.7	0.7%	13.9	1.4%	8.6	0.9%
Aug	9.7	1.8%	6.3	1.1%	6.3	0.9%	13.7	1.4%	9.5	1.0%
Sep	4.1	0.8%	3.7	0.7%	4.2	0.6%	7.9	0.8%	1.8	0.2%
Oct	1.4	0.3%	1.8	0.3%	1.1	0.1%	7.9	0.8%	1.7	0.2%
Nov	1.2	0.2%	1.0	0.2%	1.1	0.1%	3.3	0.3%	1.1	0.1%
Dec	1.5	0.3%	0.8	0.1%	3.3	0.4%	4.4	0.4%	1.0	0.0%

Table C-18 Average real-time, offer-capped MW: Calendar years 2002 to 2006

	2002		2003		2004		2005		2006	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	89.5	0.3%	86.8	0.2%	175.0	0.4%	208.9	0.3%	42.1	0.1%
Feb	45.9	0.2%	74.2	0.2%	86.8	0.2%	144.9	0.2%	67.1	0.1%
Mar	24.1	0.1%	44.0	0.1%	76.2	0.2%	74.2	0.1%	87.6	0.1%
Apr	62.0	0.2%	28.8	0.1%	115.2	0.3%	58.8	0.1%	75.3	0.1%
May	63.0	0.2%	101.2	0.3%	257.1	0.5%	77.9	0.1%	135.6	0.2%
Jun	104.7	0.3%	110.0	0.3%	166.8	0.3%	652.1	0.7%	160.1	0.2%
Jul	218.1	0.6%	251.6	0.6%	331.9	0.6%	818.8	0.9%	505.8	0.5%
Aug	311.2	0.7%	293.9	0.7%	450.4	0.8%	908.4	1.0%	517.8	0.6%
Sep	176.8	0.5%	240.8	0.7%	268.5	0.5%	476.9	0.6%	68.7	0.1%
Oct	92.0	0.3%	96.0	0.3%	77.2	0.1%	337.5	0.5%	49.4	0.1%
Nov	55.3	0.2%	53.5	0.2%	110.4	0.2%	129.4	0.2%	30.5	0.0%
Dec	51.6	0.1%	44.0	0.1%	202.0	0.3%	155.5	0.2%	11.5	0.0%

In order to help understand the frequency of offer capping in more detail, Table C-19 through Table C-22 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the year indicated. For example, in 2005 19 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 19 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 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.

Table C-19 Offer-capped unit statistics: Calendar year 2002

Percentage of Offer-Capped Run Hours	2002 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	1	1	2	5	6	6
80%	4	4	8	15	20	20
75%	4	4	8	16	26	26
60%	4	4	10	19	32	39
50%	4	5	17	26	39	54
25%	6	7	19	28	51	122
10%	6	8	20	29	61	169

Table C-20 Offer-capped unit statistics: Calendar year 2003

Percentage of Offer-Capped Run Hours	2003 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	0	0	0	0	0	1
80%	0	1	1	1	2	10
75%	1	2	2	5	9	18
60%	1	2	2	8	16	39
50%	1	2	2	11	21	51
25%	5	9	11	20	33	97
10%	6	10	12	23	47	150

Table C-21 Offer-capped unit statistics: Calendar year 2004

Percentage of Offer-Capped Run Hours	2004 Minimum Offer-Capped Hours 500	400	300	200	100	1
90%	0	1	2	7	10	15
80%	3	4	5	15	24	38
75%	4	5	10	20	30	49
60%	5	8	13	23	34	70
50%	5	8	13	24	36	80
25%	6	10	16	30	48	128
10%	8	12	20	37	71	189

Table C-22 Offer-capped unit statistics: Calendar year 2005

Percentage of Offer-Capped Run Hours	2005 Minimum Offer-Capped Hours 500	400	300	200	100	1
90%	12	13	13	14	16	17
80%	19	26	26	33	41	53
75%	19	27	30	40	55	70
60%	20	28	35	49	75	102
50%	20	28	37	51	79	115
25%	22	39	49	66	104	194
10%	22	39	50	67	111	234

Locational Net Revenue – Perfect Dispatch

In order to show how net revenue varies by location, balancing energy market net revenues were calculated for each of the 17 current PJM control zones for the perfect dispatch scenarios. The perfect dispatch results are presented in Table C-23, Table C-24 and Table C-25 for new entry, combustion turbine (CT), combined-cycle (CC) and pulverized coal (CP) generators. Net revenues are shown for a transmission zone only if that zone was integrated into PJM for the entire calendar year. The tables show the balancing energy market net revenue using PJM average prices and the differential net revenues for each zone. For example, in Table C-23, the 2006 calendar year net revenues for a CT plant under perfect dispatch using the average PJM LMP is $22,031 per installed MW-year. The net revenue for the same plant located in the ComEd Control Zone is $7,813 per installed MW-year less than the PJM systemwide net revenue, or $14,218 per installed MW-year. The net revenue for the same plant located in the PEPCO Control Zone is $44,666 per installed MW-year more than the PJM systemwide net revenue, or $66,697 per installed MW-year.

Table C-23 Balancing energy market net revenues by control zone for a CT under perfect dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$62,065	$16,476	$39,269	$23,232	$12,154	$8,063	$15,741	$22,031	$24,879
AECO	$701	$4,687	$12,580	$6,460	$4,458	$12,311	$23,114	$22,095	$10,801
AEP	NA	NA	NA	NA	NA	NA	($10,023)	($12,115)	($11,069)
AP	NA	NA	NA	NA	($3,724)	($1,487)	$386	($1,170)	($1,499)
BGE	($952)	($2,101)	($8,269)	$7,201	$3,025	$4,511	$28,274	$36,001	$8,461
ComEd	NA	NA	NA	NA	NA	NA	($5,882)	($7,813)	($6,848)
DAY	NA	NA	NA	NA	NA	NA	($9,996)	($12,878)	($11,437)
Dominion	NA	NA	NA	NA	NA	NA	NA	$32,158	$32,158
DPL	$2,342	$5,936	$23,656	$9,533	$4,715	$5,959	$16,627	$12,863	$10,204
DLCO	NA	NA	NA	NA	NA	NA	($10,085)	($11,790)	($10,938)
JCPL	$408	$1,742	$7,837	($579)	$765	$23,333	$21,928	$9,964	$8,175
Met-Ed	($604)	($818)	$514	$3,279	$1,513	$3,387	$15,910	$12,289	$4,434
PECO	$1,038	$4,196	$8,271	$491	$3,403	$2,824	$17,854	$10,432	$6,064
PENELEC	($445)	($1,220)	($13,673)	$1,088	($1,531)	($181)	($2,921)	($8,369)	($3,407)
PEPCO	($1,208)	($2,324)	($13,673)	$9,209	$3,745	$6,581	$34,341	$44,666	$10,167
PPL	($266)	($1,000)	($4,046)	($2,396)	($95)	$227	$11,990	$6,575	$1,374
PSEG	$945	$2,807	$8,253	($891)	$3,302	$21,656	$24,017	$10,763	$8,856
RECO	NA	NA	NA	NA	$3,618	$7,759	$18,420	$8,086	$9,471

Table C-24 Balancing energy market net revenues by control zone for a CC under perfect dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$89,600	$42,647	$68,949	$51,639	$50,346	$49,600	$68,308	$70,828	$61,490
AECO	$369	$6,037	$15,136	$8,588	$8,818	$29,242	$52,839	$40,173	$20,150
AEP	NA	NA	NA	NA	NA	NA	($30,862)	($30,171)	($30,517)
AP	NA	NA	NA	NA	($10,543)	($8,220)	$2,646	($3,029)	($4,787)
BGE	($1,922)	($4,282)	($12,000)	$7,613	$4,565	$8,908	$53,397	$53,484	$13,721
ComEd	NA	NA	NA	NA	NA	NA	($19,646)	($21,879)	($20,763)
DAY	NA	NA	NA	NA	NA	NA	($32,534)	($32,786)	($32,660)
Dominion	NA	NA	NA	NA	NA	NA	NA	$49,777	$49,777
DPL	$3,224	$10,513	$27,928	$11,314	$8,195	$15,425	$36,869	$22,338	$16,976
DLCO	NA	NA	NA	NA	NA	NA	($33,810)	($34,095)	($33,953)
JCPL	$182	$1,848	$7,427	($1,241)	$469	$40,808	$45,033	$17,002	$13,941
Met-Ed	($1,029)	($2,294)	($1,100)	$3,042	$748	$5,560	$31,842	$20,632	$7,175
PECO	$763	$5,198	$7,722	$121	$5,321	$9,844	$36,711	$18,673	$10,544
PENELEC	($473)	($1,481)	($17,839)	$6,953	($4,619)	($6,547)	($7,640)	($17,668)	($6,164)
PEPCO	($2,253)	($4,652)	($17,839)	$9,218	$5,996	$12,226	$62,274	$63,985	$16,119
PPL	($652)	($2,651)	($6,506)	($4,155)	($1,604)	($1,417)	$24,933	$12,676	$2,578
PSEG	$2,403	$7,204	$10,855	($619)	$8,250	$40,430	$55,133	$25,820	$18,685
RECO	NA	NA	NA	NA	$9,106	$20,924	$43,340	$21,713	$23,771

Table C-25 Balancing energy market net revenues by control zone for a CP under perfect dispatch (Dollars per installed MW-year): Calendar years 1999 to 2006

Zone	1999	2000	2001	2002	2003	2004	2005	2006	Average
PJM	$101,011	$112,202	$106,866	$101,345	$166,540	$136,280	$232,351	$184,241	$142,605
AECO	($256)	$5,122	$15,153	$9,430	$9,665	$41,508	$77,363	$45,776	$25,470
AEP	NA	NA	NA	NA	NA	NA	($74,453)	($54,313)	($64,383)
AP	NA	NA	NA	NA	($19,807)	($11,498)	$1,774	($4,901)	($8,608)
BGE	($2,680)	($8,863)	($13,513)	$7,067	$3,350	$12,914	$72,679	$59,843	$16,350
ComEd	NA	NA	NA	NA	NA	NA	($80,567)	($59,069)	($69,818)
DAY	NA	NA	NA	NA	NA	NA	($84,755)	($62,175)	($73,465)
Dominion	NA	NA	NA	NA	NA	NA	NA	$51,982	$51,982
DPL	$3,359	$16,332	$34,181	$12,795	$9,375	$24,712	$56,735	$25,357	$22,856
DLCO	NA	NA	NA	NA	NA	NA	($91,771)	($70,030)	($80,900)
JCPL	($455)	($1,051)	$6,853	($2,037)	($1,885)	$51,590	$63,687	$18,146	$16,856
Met-Ed	($1,714)	($6,087)	($2,305)	$2,424	($1,933)	$9,143	$46,129	$23,134	$8,599
PECO	$137	$3,590	$7,229	($651)	$4,453	$18,297	$55,294	$20,703	$13,632
PENELEC	($966)	$794	($19,759)	$10,429	($5,796)	($11,158)	($13,447)	($24,558)	($8,058)
PEPCO	($3,012)	($9,180)	($19,759)	$8,413	$5,062	$16,512	$83,162	$70,889	$19,011
PPL	($1,319)	($7,108)	($7,976)	($6,393)	($5,585)	$1,040	$36,995	$14,246	$2,988
PSEG	$2,532	$12,789	$13,295	($321)	$14,169	$54,258	$84,691	$36,312	$27,216
RECO	NA	NA	NA	NA	$16,484	$32,902	$68,468	$31,036	$37,223

APPENDIX D – INTERCHANGE TRANSACTIONS

In competitive wholesale power markets, price signals guide purchase and sales decisions. If neighboring wholesale power markets incorporate security-constrained nodal pricing and are designed and managed well, the interface pricing points allow economic signals to guide efficient import and export decisions. When a competitive market shares a boundary with an area reliant on bilateral contracts and associated contract paths to manage transactions, however, the independent system operator (ISO) or regional transmission organization (RTO) needs to define its interface pricing points so that imports and exports, especially under conditions of congestion, face price signals that are consistent with the underlying reality of generation and transmission resources.

PJM has an established process for developing and implementing interface prices. PJM increased the sophistication of that process in 2002 by addressing the causes of loop flow. PJM further developed the application of interface pricing for the integration of the Commonwealth Edison Company (ComEd) Control Area on May 1, 2004,[1] and on October 1, 2004, with the Phase 3 integration of the American Electric Power Company (AEP) and The Dayton Power & Light Company (DAY) Control Zones.[2]

In 2005 the integrations of Phases 4 and 5 brought two new zones into the PJM system, the Duquesne Light Company (DLCO) and the Dominion Control Zones. As a result, both the PJM/DLCO and PJM/Dominion Virginia Power (VAP) interfaces were retired. In addition, the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) started its market-based system on April 1, 2005. The startup required establishment of a new interface pricing point: MISO.

On October 1, 2006, the southeast and southwest pricing points were retired and replaced with a single south pricing point, the SOUTHIMP (import) and the SOUTHEXP (export) pricing points, in response to PJM's ongoing analysis of loop flow.

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the New York Independent System Operator (NYISO), if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.

Institutional difference between PJM and NYISO markets partially explains observed differences in border prices.[3] The NYISO requires hourly bids or offer prices for each export or import transaction and clears its

1 Control zones and control areas are geographic areas that customarily bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a description of the evolution of the PJM footprint during 2004 and 2005.

2 Control areas external to PJM are referred to as control areas not control zones. For example, the FirstEnergy control area is not referred to as the FirstEnergy control zone.

3 See *2005 State of the Market Report* (March 8, 2006), pp. 195-198.

market each hour based on hourly bids.[4] Import transactions to NYISO are treated by NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by NYISO as price-capped load offers. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. It is a function of time lags built into the functioning of the real-time commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no less than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of NYISO, the price the participants are willing to pay. The required lead-time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single hour.

PJM operating practices provide that market participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[5] The duration of the requested transaction can vary from a single hour to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, only about 1 percent of all transactions submit an associated price. Transactions are accepted in order of submission based on whether PJM has the capability to import or export the requested MW. Since they receive the actual real-time price for their scheduled imports or exports, these transactions are price takers in the Real-Time Market. As in the NYISO, the required lead-time means that participants must make offers to buy or sell MW based on expected prices, but the lead-time is substantially shorter in the PJM market.

The NYISO rules provide that RTC results should be available 45 minutes before the operating hour. Thus winning bidders have 25 minutes from the time when RTC results indicate that their transaction will flow until the time when they must get their transaction cleared with PJM to meet the 20-minute requirement. To get a transaction cleared with PJM, the market participant must have a valid North American Electric Reliability Council (NERC) Tag, an Open Access Same-Time Information System (OASIS) reservation, a PJM schedule and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead-times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

4 See NYISO, "NYISO Transmission Services Manual, Version 2.0" (February 1, 2005) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

5 See PJM "Manual 11: Scheduling Operations" (August 11, 2006) (Accessed January 8, 2007) <http://www.pjm.com/contributions/pjm-manuals/pdf/m11.pdf > (823 KB).

Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts[6]

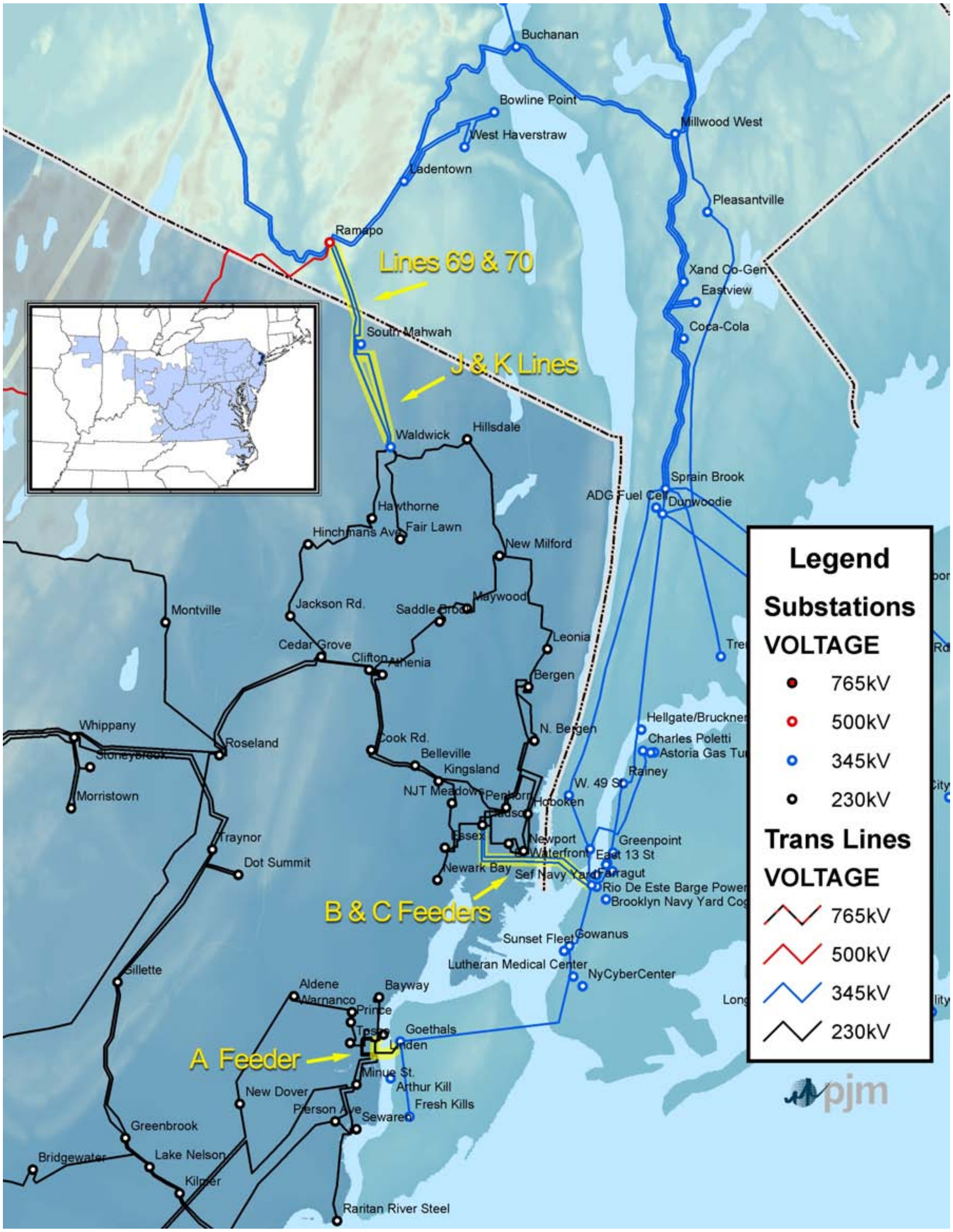
To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the United States Federal Energy Regulatory Commission (FERC) in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[7] In July 2005, the protocol was implemented.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G then wheels the power across its system and delivers it back to Con Edison across lines connecting directly into the city. (See Figure D-1.) Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to New Milford Switching Station (New Jersey) via the J line and ultimately from Linden Switching Station (New Jersey) to Goethals Substation (New York) and from Hudson Generating Station (New Jersey) to Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had underdelivered on the agreements and asked the FERC to resolve the issue.

6 Prior state of the market reports indicated that this contract is an agreement between Con Edison and PSEG. The contract is between Con Edison and PSE&G, a wholly owned subsidiary of PSEG.

7 111 FERC ¶ 61,228 (2005).

Figure D-1 Con Edison and PSE&G wheel



Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[8] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the contracted flow under each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion charges associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned Financial Transmission Rights (FTRs) associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. During 2006, the PSE&G FTR revenues were less than the associated congestion charges by $0.4 million ($2.1 million in 2005) because, for the entire PJM FTR Market, revenue was insufficient to fully fund FTRs. Under the FERC order, Con Edison receives credits on an hourly basis for up to the amount of its congestion charges associated with its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. During 2006, Con Edison's congestion credits were less than the associated congestion charges by $0.7 million ($8.2 million in 2005). (See Table D-1.)

8 111 FERC ¶ 61,228 (2005).

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2006

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Jan	Congestion Charge	$101,316.00		$101,316.00	$151,974.00		$151,974.00
	Congestion Credit			$183,232.00			$151,974.00
	Previous month(s) credit adj.						$112,720.07
	Net Charge			($81,916.00)			($112,720.07)
Feb	Congestion Charge	$122,168.00		$122,168.00	$183,252.00		$183,252.00
	Congestion Credit			$35,898.68			$171,986.43
	Previous month(s) credit adj.						$27,727.37
	Net Charge			$86,269.32			($16,461.80)
Mar	Congestion Charge	$246,730.93	($1,272.55)	$245,458.38	384,624.00		$384,624.00
	Congestion Credit			$46,772.29			$304,471.59
	Previous month(s) credit adj.						$44.34
	Net Charge			$198,686.09			$80,108.07
Apr	Congestion Charge	$628,037.55	($2,539.34)	$625,498.21	$961,902.00		$961,902.00
	Congestion Credit			$23,514.51			$581,564.88
	Previous month(s) credit adj.						$181.85
	Net Charge			$601,983.70			$380,155.27
May	Congestion Charge	$235,969.22	$14,947.12	$250,916.34	$368,940.00		$368,940.00
	Congestion Credit			$61,216.94			$337,563.65
	Previous month(s) credit adj.						$124.94
	Net Charge			$189,699.40			$31,251.41
Jun	Congestion Charge	$168,488.00		$168,488.00	$252,732.00		$252,732.00
	Congestion Credit			$79,365.65			$241,690.96
	Previous month(s) credit adj.						$6,993.82
	Net Charge			$89,122.35			$4,047.22
Jul	Congestion Charge	$248,572.00		$248,572.00	$372,858.00		$372,858.00
	Congestion Credit			$252,912.00			$372,858.00
	Previous month(s) credit adj.						$11,041.04
	Net Charge			($4,340.00)			($11,041.04)
Aug	Congestion Charge	$550,232.00		$550,232.00	$825,348.00		$825,348.00
	Congestion Credit			$553,096.00			$825,348.00
	Previous month(s) credit adj.						
	Net Charge			($2,864.00)			$0.00
Sep	Congestion Charge	$359,722.52	($737.90)	$358,984.62	$548,526.00		$548,526.00
	Congestion Credit			$368,622.52			$548,526.00
	Previous month(s) credit adj.						
	Net Charge			($9,637.90)			$0.00

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2006, continued

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Oct	Congestion Charge	$106,264.00		$106,264.00	$159,396.00		$159,396.00
	Congestion Credit			$200,864.00			$159,396.00
	Previous month(s) credit adj.						
	Net Charge			($94,600.00)			$0.00
Nov	Congestion Charge	($182,216.00)		($182,216.00)	($273,324.00)		($273,324.00)
	Congestion Credit			$43,868.00			($273,324.00)
	Previous month(s) credit adj.						
	Net Charge			($226,084.00)			$0.00
Dec	Congestion Charge	$111,736.66	($1,232.20)	$110,504.46	$223,032.00		$223,032.00
	Congestion Credit			$187,421.04			$223,032.00
	Previous month(s) credit adj.						
	Net Charge			($76,916.58)			$0.00
Total	Congestion Charge	$2,697,020.88	$9,165.13	$2,706,186.01	$4,159,260.00	$0.00	$4,159,260.00
	Congestion Credit			$2,036,783.63			$3,645,087.51
	Credit Adj.			$0.00			$158,833.43
	Net Charge			$669,402.38			$355,339.06

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. As a general matter, this has not occurred.

APPENDIX E – CAPACITY MARKET[1]

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Before retail restructuring, the original PJM members had determined their loads and related capacity obligations annually. Combined with state regulatory requirements to build and incentives to maintain adequate capacity, this system created a reliable pool, where capacity and energy were adequate to meet customer needs and where capacity costs were borne equitably by members and their loads.

Capacity obligations continue to be critical to maintaining reliability and to contribute to the effective, competitive operation of the PJM Energy Market. Adequate capacity resources, equal to or greater than expected load plus a reserve margin, help to ensure that energy is available on even the highest load days.

On January 1, 1999, in response to retail restructuring requirements, PJM introduced a transparent, PJM-run market in capacity credits.[2] New retail market entrants needed a way to acquire capacity credits to meet obligations associated with competitively gained load. Existing utilities needed a way to sell excess capacity credits when load was lost to new competitors. The PJM Capacity Credit Market (CCM) provides a mechanism to balance supply and demand for capacity credits not met through the bilateral market or self-supply. The PJM CCM is designed to provide a transparent mechanism through which all competitors can buy and sell capacity based on need.

Under the Reliability Assurance Agreement (RAA) governing the Capacity Market operated by the PJM regional transmission organization (RTO), each load-serving entity (LSE) must own or purchase capacity resources greater than, or equal to, its capacity obligation. To cover this responsibility, LSEs may own or purchase capacity credits, unit-specific capacity or capacity imports.

Capacity Obligations

As shown in Equation E-1, in the PJM Capacity Market, load forecasts are used to determine a forecast peak load. These forecast peak-load values are further adjusted to establish capacity obligations. [3]

1 On June 1, 2005, the PJM Capacity Market became the sole capacity market for all control zones. It is referred to here as the PJM Capacity Market, the PJM Capacity Credit Market or simply PJM. The Commonwealth Edison Company (ComEd) capacity market was an interim market limited to that control zone. It began on June 1, 2004, and continued through May 31, 2005. Beginning on June 1, 2005, all control zones participated in a single PJM Capacity Market. The interim capacity market is referred to as the ComEd capacity market, the ComEd capacity credit market (CCM) or simply ComEd.

Control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The names apply to the geographic area, not to any single company. See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a description of the evolution of the PJM footprint during 2004 and 2005.

2 The first PJM Capacity Credit Markets (CCMs) were run in late 1998, with an effective date of January 1, 1999.

3 See PJM "Manual 17: Capacity Obligations," Revision 6 (June 1, 2005) <http://www.pjm.com/ contributions/pjm-manuals/pdf/m17v06.pdf> (105 KB).

The adjusted forecast peak-load value is multiplied by the forecast pool requirement (FPR) to determine the unforced capacity obligation for PJM.[4] The FPR is equal to one plus a reserve margin, multiplied by the PJM unforced outage factor. An LSE's unforced capacity obligation for a zone is based on its customers' aggregate share of the prior summer's weather-normalized zonal peak load multiplied by zonal scaling factors[5] and the FPR. The LSE's zonal obligation may be further adjusted for ALM credits. The FPR is set for each planning period which commences every June 1.

Equation E-1 Calculating PJM unforced capacity obligations

Unforced Capacity Obligation = [(Peak Load • Zonal Scaling Factor) – (ALM • ALM Factor)] • Forecast Pool Requirement

Meeting Capacity Obligations

In this Capacity Market, an LSE's load can change on a daily basis as customers switch suppliers. The unforced capacity position of every such LSE is calculated daily when its capacity resources are compared to its capacity obligation to determine if any LSE is short of capacity resources. Deficient entities must contract for capacity resources to satisfy their deficiency. Any LSE that remains deficient must pay an interval penalty equal to the capacity deficiency rate (CDR) times the number of days in an interval.[6] If an LSE is short because of a short-term load increase, it pays only the daily penalty until the end of the month. In no case is a deficient LSE charged more than the CDR multiplied by the number of days in the interval, multiplied by each MW of deficiency.

Capacity Resources

Capacity resources are defined as MW of net generating capacity meeting PJM-specific criteria. They may be located within or outside of PJM, but they must be committed to serving load within PJM. All capacity resources must pass tests regarding the capability of generation to serve load and to deliver energy. This latter criterion requires adequate transmission service.[7]

Capacity resources may be owned, or they may be bought in three different ways:

- **Bilateral, from an Internal PJM Source.** Internal, bilateral purchases may be in the form of a sale of all or part of a specific generating unit, or in the form of a capacity credit, measured in MW and defined in terms of unforced capacity.

- **Bilateral, from a Generating Unit External to PJM.** External, bilateral purchases (capacity imports) must meet PJM criteria, including that imports are from specific generating units and that sellers have firm transmission from the identified units to the metered boundaries of the RTO.

4 Adjusted for active load-management (ALM).

5 Zonal scaling factors are applied to historical peak loads to produce forecasted zonal peak loads.

6 The CDR is a function both of the annual carrying costs of a combustion turbine (CT) and the forced outage rate and thus may change annually. The CDR was changed to $170.09 per MW-day, effective June 1, 2004, to $171.18 per MW-day, effective January 1, 2005, and to $170.45 per MW-day, effective June 1, 2006.

7 See PJM "Reliability Assurance Agreement," Capacity Resources (May 17, 2004), p. 2.

- **Capacity Credit Market.** For the PJM Capacity Market, market purchases may be made from the Daily, Monthly or Multimonthly CCM Auctions. For the interim ComEd capacity market, market purchases could be made from the ComEd monthly or multimonthly capacity credit market auctions.

The sale of a generating unit as a capacity resource within the PJM Control Area entails obligations for the generation owner. The first four of these requirements, listed below, are essential to the definition of a capacity resource and contribute directly to system reliability.

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity resources to the PJM Capacity Market from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit if the energy is sold outside of PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures.[8] The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load within the Control Area. When PJM invokes the recall right, the energy supplier is paid the PJM real-time energy market price.

- **Day-Ahead Energy Market Offer Requirement.** Owners of PJM capacity resources are required to offer their output into PJM's Day-Ahead Energy Market. When LSEs purchase capacity, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, PJM capacity resource owners must provide the offered energy at the offered price if the offer is accepted in the Day-Ahead Energy Market. This energy can be provided by the specific unit offered, by a bilateral energy purchase, or by an energy purchase from the Real-Time Energy Market.

- **Deliverability.** To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to load in the PJM Control Area. Capacity resources must be deliverable,[9] consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency. In addition, for external capacity resources used to meet an accounted-for obligation within PJM, capacity and energy must be delivered to the metered boundaries of the RTO through firm transmission service.

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.[10]

Market Dynamics

RAA procedures determine the total capacity obligation for the PJM Capacity Market and thus the total demand for capacity in the market. The RAA includes rules for allocating total capacity obligation to individual LSEs in each market. An LSE's deficiency is equivalent to its allocated capacity obligation, net of bilateral contracts, self-supply and the active load management (ALM). LSEs bid this deficiency into the appropriate Capacity Credit Market Auctions.

8 See PJM "Manual 13: Emergency Operations," Revision 19 (October 1, 2004) <http://www.pjm.com/ contributions/pjm-manuals/pdf/m13v19.pdf> (461 KB).

9 Deliverable per PJM "Reliability Assurance Agreement," Schedule 10 (May 17, 2004), p. 52 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

10 See PJM "Reliability Assurance Agreement," Schedule 12 (May 17, 2004), p. 57 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

The short- and intermediate-term supply of capacity credits in the Capacity Credit Market is a function of: physical capacity in the Control Area; prices of energy and capacity in external markets; prices in the PJM Energy and Capacity Markets; capacity resource imports and exports; and transmission service availability and price. The long-term supply of capacity credits is a function of physical capacity in the Control Area which is in turn a function of incentives to build and maintain capacity.

While physical generating units in PJM are the primary source of capacity resources, capacity resources can be exported from PJM and imported into PJM, subject to transmission limitations. It is the ability to export and to import capacity resources that makes capacity supply in PJM a function of price in both internal and external capacity and energy markets.

In capacity markets, as in other markets, market power is the ability of a market participant to increase market price above the competitive level. The competitive market price is the marginal cost of producing the last unit of output, assuming no scarcity and including opportunity costs. For capacity, the opportunity cost of selling into a Capacity Market operated by the RTO is the additional revenue foregone by not selling into an external energy and/or capacity market.

Generation owners can be expected to sell capacity into the most profitable market. A competitive price in a capacity market is a function of the marginal cost of capacity. The marginal cost of capacity is, in turn, determined by the time period over which a choice is made as well as by the alternative opportunities available to the generation owner. If an owner is considering whether to sell a capacity resource for a year, marginal cost would include the incremental cost of maintaining the unit for that year (going forward cost) so that it can qualify as a capacity resource and any relevant opportunity cost. If an owner is considering whether to sell a capacity resource for a day, the only relevant cost is the opportunity cost. The opportunity cost associated with the sale of a capacity resource is a function of the expected probability that the energy will be recalled and the expected distribution of the difference between external and internal energy prices.

Generators can be expected to evaluate the opportunities to sell capacity on a continuing basis, over a variety of time frames, depending on the rules of the capacity markets. The existence of interval markets makes the generators' decisions more dependent on assessments of seasonal energy market price differentials and recall probabilities. With longer capacity obligations, the likelihood of the net external energy market price differential exceeding the capacity penalty for the period is lower and, therefore, the incentives to sell the system short are lower.

2005 Baseline Capacity Market Data

From June 2004 through May 2005, a separate ComEd capacity credit market operated under PJM rules, but with capacity obligations and capabilities measured in installed MW. On June 1, 2005, all ComEd capacity markets were fully integrated into the PJM capacity marketplace. To analyze PJM Capacity Market performance during 2006 as compared to 2005, the *2006 State of the Market Report* limits the relevant 2005 period to the one that started on June 1, 2005, and ended on December 31, 2005, when all capacity became measured by unforced MW. The report refers to it as the 2005 ComEd post capacity integration (PCI) period (i.e., the 2005 ComEd PCI period).

The following tables provide the baseline data for this 2005 ComEd PCI period, to which the 2006 Capacity Market results are compared.

Table E-1 PJM's ComEd PCI period capacity summary (MW): June to December 2005

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	163,269	436	162,588	163,951
Unforced Capacity	152,780	680	151,868	153,746
Obligation	142,783	237	142,213	143,260
Sum of Excess	9,997	769	8,665	11,056
Sum of Deficiency	0	0	0	0
Net Excess	9,997	769	8,665	11,056
Imports	3,997	266	3,728	4,391
Exports	5,032	563	4,278	5,746
Net Exchange	(1,035)	394	(1,655)	(486)
Unit-Specific Transactions	18,354	457	17,803	19,064
Capacity Credit Transactions	138,017	1,685	135,666	140,859
Internal Bilateral Transactions	156,371	1,633	153,966	158,940
Daily Capacity Credits	1,605	379	1,025	2,455
Monthly Capacity Credits	1,221	271	699	1,539
Multimonthly Capacity Credits	4,179	264	3,744	4,497
All Capacity Credits	7,005	598	6,079	8,103
ALM Credits	2,042	5	2,035	2,065

Table E-2 PJM's ComEd PCI period capacity market load obligation served: June to December 2005

	Average Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Jun	89,798	23,945	12,259	604	6,604	175	8,958	142,343
Jul	90,088	23,943	12,437	604	6,598	162	9,001	142,833
Aug	89,750	24,066	12,572	604	6,687	162	9,059	142,900
Sep	89,917	24,009	12,656	604	6,740	162	9,081	143,169
Oct	89,925	23,787	12,452	608	6,684	164	9,092	142,712
Nov	90,097	23,817	12,177	608	6,865	164	9,015	142,743
Dec	90,563	23,857	12,005	609	6,804	164	8,777	142,779
Average	90,021	23,918	12,365	606	6,711	165	8,997	142,783
Percent of Total Obligation	63.0%	16.8%	8.7%	0.4%	4.7%	0.1%	6.3%	100.0%

Table E-3 PJM's ComEd PCI period capacity market load obligation served by PJM EDCs and affiliates: June to December 2005

	PJM EDCs					PJM EDC Generating Affiliates					PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun	50,291	729	40,840	89,798	2,062	65,660	(1,650)	(37,717)	23,945	2,348	0	1,106	11,497	12,259	344
Jul	50,291	417	41,234	90,088	1,854	65,601	(2,067)	(37,491)	23,943	2,100	0	1,598	11,153	12,437	314
Aug	50,291	303	40,873	89,750	1,717	65,600	(1,775)	(37,725)	24,066	2,034	0	1,727	11,112	12,572	267
Sep	50,365	181	40,912	89,917	1,541	65,553	(1,807)	(37,943)	24,009	1,794	0	1,832	11,103	12,656	279
Oct	51,123	679	41,126	89,925	3,003	65,420	(1,486)	(38,562)	23,787	1,585	0	1,842	10,979	12,452	369
Nov	51,133	448	41,378	90,097	2,862	65,420	(1,481)	(38,793)	23,817	1,329	0	1,542	10,936	12,177	301
Dec	51,380	568	41,443	90,563	2,828	65,439	(1,767)	(38,910)	23,857	905	0	1,547	10,778	12,005	320
Average	50,698	475	41,116	90,021	2,268	65,527	(1,720)	(38,163)	23,918	1,726	0	1,601	11,078	12,365	314
Percent of Total Obligation	56.0%	0.5%	45.6%	102.1%	2.1%	273.4%	(7.6%)	(157.2%)	108.6%	8.6%	0.0%	12.6%	89.9%	102.5%	2.5%

Table E-4 PJM's ComEd PCI period capacity market load obligation served by non-PJM EDC affiliates: June to December 2005

	Non-PJM EDC Generating Affiliates					Non-PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun	13,665	24	(10,037)	604	3,048	0	617	6,690	6,604	703
Jul	13,668	(97)	(10,028)	604	2,939	0	706	6,467	6,598	575
Aug	13,668	(161)	(9,954)	604	2,949	0	545	6,526	6,687	384
Sep	13,668	(135)	(10,059)	604	2,870	0	573	6,655	6,740	488
Oct	13,555	(299)	(10,151)	608	2,497	0	532	7,121	6,684	969
Nov	13,553	(200)	(10,191)	608	2,554	0	505	7,313	6,865	953
Dec	13,553	(213)	(10,174)	609	2,557	0	662	7,305	6,804	1,163
Average	13,618	(155)	(10,085)	606	2,772	0	592	6,868	6,711	749
Percent of Total Obligation	2261.8%	(15.4%)	(1658.0%)	588.4%	488.4%	0.0%	9.2%	98.9%	108.1%	8.1%

Table E-5 PJM's ComEd PCI period capacity market load obligation served by non-EDC affiliates: June to December 2005

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun	23,954	(1,135)	(21,783)	175	861	0	308	9,249	8,958	599
Jul	23,975	(922)	(21,539)	162	1,352	0	364	9,058	9,001	421
Aug	23,973	(534)	(21,860)	162	1,417	0	(105)	9,587	9,059	423
Sep	23,971	(1,072)	(21,358)	162	1,379	0	427	9,203	9,081	549
Oct	24,081	(1,299)	(20,457)	164	2,161	0	30	9,407	9,092	345
Nov	24,048	(830)	(20,395)	164	2,659	0	16	9,238	9,015	239
Dec	23,809	(857)	(20,196)	164	2,592	0	60	8,888	8,777	171
Average	23,973	(949)	(21,083)	165	1,776	0	156	9,233	8,997	392
Percent of Total Obligation	14486.8%	(551.6%)	(13077.3%)	857.9%	757.9%	0.0%	2.7%	102.8%	105.5%	5.5%

Table E-6 PJM's ComEd PCI period CCM HHI: June to December 2005

	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	1711	2911
Minimum	1313	1484
Maximum	2219	10000
Highest Market Share (One Auction)	42.8%	100.0%
Highest Market Share (All Auctions)	31.4%	25.3%
# Auctions	214	35
# Auctions with HHI >1800	91	31
% Auctions with HHI >1800	42.5%	88.6%

Table E-7 PJM's ComEd PCI period CCM three pivotal supplier residual supply index (RSI): June to December 2005

	Daily Market RSI_3	Monthly and Multimonthly Market RSI_3
Average	0.48	0.18
Minimum	0.27	0.00
Maximum	0.85	1.16
# Auctions	214	34
# Auctions with = 1 Pivotal Supplier	153	33
% Auctions with = 1 Pivotal Supplier	71.5%	97.1%
# Auctions with <= 3 Pivotal Suppliers	214	34
% Auctions with <= 3 Pivotal Suppliers	100.0%	100.0%

Table E-8 PJM's ComEd PCI period CCM: June to December 2005

	Average Daily Capacity Credits (MW)			Weighted-Average Price ($ per MW-day)		
	Daily CCM	Monthly and Multimonthly CCM	Combined Markets	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
Jun	1,112	5,053	6,165	$0.00	$9.47	$7.76
Jul	1,290	5,497	6,787	$0.05	$8.79	$7.13
Aug	1,476	5,216	6,692	$0.05	$7.29	$5.69
Sep	1,387	5,219	6,606	$0.05	$7.00	$5.54
Oct	1,787	5,282	7,069	$0.64	$5.32	$4.14
Nov	1,948	5,883	7,831	$0.62	$4.85	$3.80
Dec	2,225	5,648	7,873	$0.02	$5.08	$3.65
Average	1,605	5,400	7,005	$0.23	$6.77	$5.27

Generator Performance: NERC OMC Outage Cause Codes

Table E-9 includes a list of the North American Electric Reliability Council (NERC) GADS cause codes deemed outside management control (OMC). PJM does not automatically include cause codes 9200-9299 as outside management control for the purposes of calculating unforced capacity, with the exception of code 9250 under certain conditions.

Table E-9 NERC GADS cause codes deemed outside management control[11] (OMC)

Cause Code	Reason for Outage
3600	Switchyard transformers and associated cooling systems - external
3611	Switchyard circuit breakers - external
3612	Switchyard system protection devices - external
3619	Other switchyard equipment - external
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)
3720	Transmission equipment at the 1st substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st substation (see code 9300 if applicable)
9000	Flood
9010	Fire, not related to a specific component
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9035	Hurricane
9036	Storms (ice, snow, etc)
9040	Other catastrophe
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels
9135	Lack of water (hydro)
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems.
9200	High ash content
9210	Low grindability
9220	High sulfur content
9230	High vanadium content
9240	High sodium content
9250	Low Btu coal
9260	Low Btu oil
9270	Wet coal
9280	Frozen coal
9290	Other fuel quality problems
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiated
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings - intervenor initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

11 See NERC, "Generator Availability Data System Data Reporting Instructions," Appendix K <ftp://www.nerc.com/pub/sys/all_updl/gads/dri/Appendix-K-Outside-Plant-Management-Control.pdf> (161 KB).

APPENDIX F – ANCILLARY SERVICE MARKETS

This appendix covers two subject areas: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange, and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of generation energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[2]

Generators wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that generators be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to a regulation test pattern for 40 minutes and must reach their offered regulation capacity levels, up and down, within five minutes. Units whose monitored response is less than their offered regulation capacity have their regulating capacity reduced by PJM.[3]

Control Performance Standard (CPS) and Balancing Authority ACE Limit (BAAL)

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The purpose of the new BAAL standard is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

1 "Two additional terms may be included in ACE under certain conditions-time error bias and manual add (a PJM dispatcher term). These provide for automatic inadvertent interchange payback and error compensation, respectively." See PJM "Manual 12: Dispatching Operations," Revision 13 (May 26, 2006), Section 3, "System Control," p. 17.

2 Regulation Market business rules are defined in PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), pp. 50-58.

3 See PJM "Manual 12: Dispatching Operations," Revision 13 (May 26, 2006), Section 4, p. 29.

- **CPS1.** NERC requires that the first measure of the CPS survey provide a measure of the control area's performance. The measure is intended to provide the control area with a frequency-sensitive evaluation of how well it met its demand requirements. A minimum passing score for CPS1 is 100 percent.[4]

- **CPS2/BAAL.** NERC also requires that the second measure of the CPS survey be designed to bound ACE 10-minute averages. CPS2 provides a control measure of excessive, unscheduled power flows that could result from large ACEs. CPS2 is measured by counting the number of 10-minute periods during a month when the 10-minute average of the PJM Control Area's ACE is within defined limits known as L_{10}. The specific, 10-minute periods of each hour are those ending at 10, 20, 30, 40, 50 and 60 minutes after the hour. A passing score for CPS2 is achieved when 90 percent of these 10-minute periods during a single month are within L_{10}. From January 1 through January 31, 2006, the PJM Control Area's L_{10} standard was 281.2 MW. From February 1 through February 28, PJM's L_{10} standard was 283.9 MW. From March 1 through December 31, PJM's L_{10} standard was 284.3 MW.

- **BAAL.** Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which has established a new metric, balancing authority ACE limit (BAAL), as a possible substitute for CPS2. Participants in the field test have a waiver from meeting the CPS2 requirement for the duration of the field test. As a substitute, the field test participants are required to comply with BAAL limits, which have been established on a trial basis.[5] PJM measures the total number of minutes the BAAL limit is exceeded (high or low) compared to the total number of minutes for a month, with a passing level for this goal being set at 98 percent.

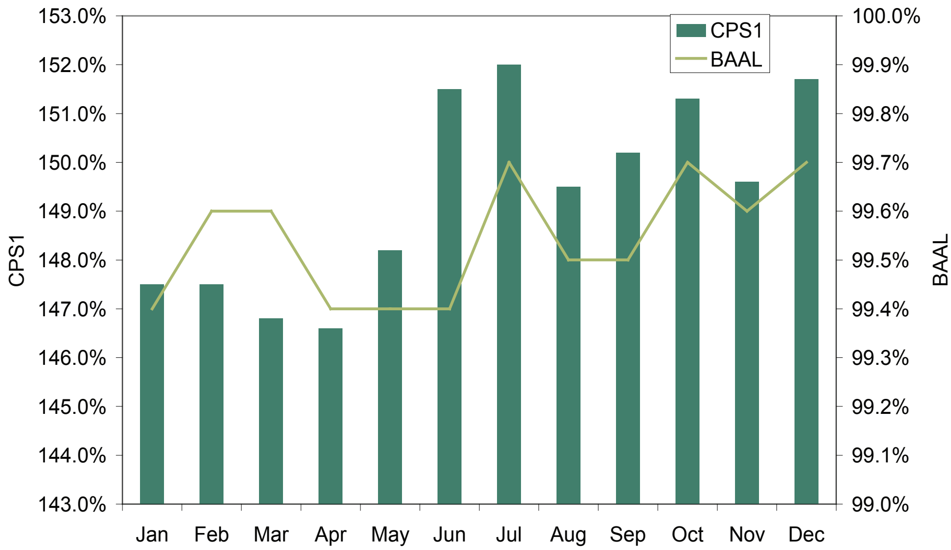
4 For more information about the definition and calculation of CPS, see PJM "Manual 12: "Dispatching Operations," Revision 13 (May 26, 2006), pp. 19-21. The formal definition of CPS1 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.1. The formal definition of CPS2 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.2.

5 See PJM "Manual 12: "Dispatching Operations," Revision 13 (May 26, 2006), pp. 19-21.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance relative to both the CPS1 and BAAL metrics was acceptable in calendar year 2006.

Figure F-1 PJM CPS1 and BAAL performance: Calendar year 2006



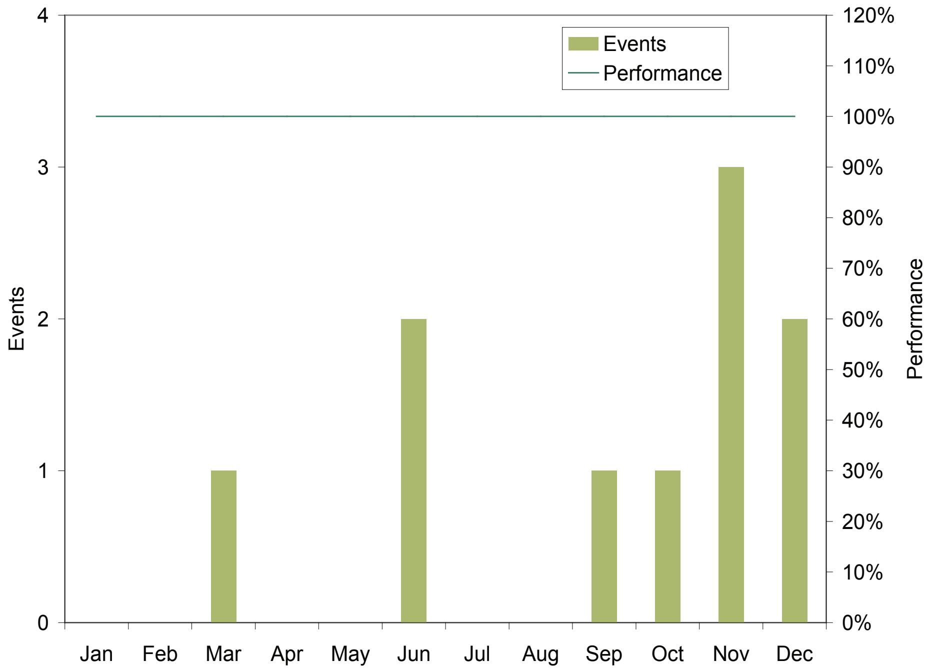
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 standard requires balancing frequency on a monthly running-average basis. Meeting the BAAL standard requires PJM dispatchers maintaining interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[6] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation over 800 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 10 DCS events during calendar year 2006 and successfully recovered from all of them. All events were caused by a major unit's tripping. Recovery times ranged from six minutes to 11 minutes. Figure F-2 illustrates the event count and performance by month. All of the events resulted in low ACE. The solution for most of the events was to declare a 100 percent spinning event.

6 For more information on the NERC DCS, see "Standard BAL-002-0 — Disturbance Control Performance" (April 1, 2005) << ftp://www.nerc.com/pub/sys/all_updl/standards/rs/BAL-002-0.pdf>> (61 KB).

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2006



Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned

Regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group by first creating a supply curve of available units and their associated regulation prices; then assigning regulation to units in increasing order of price until the regulation MW requirement is satisfied. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curve is complicated by the fact that the Synchronized Reserve Market is solved simultaneously. Regulation, synchronized reserve and the Energy Market are all co-optimized to achieve the lowest overall cost after first taking into account units that self-schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

The process by which available regulation is defined and assigned is complicated, but important to understanding regulation price and regulation market competitiveness.

- **Regulation Capacity.** The sum of the regulation MW capability of all generating units which have qualified to participate in the Regulation Market is the theoretical maximum regulation capacity. This maximum regulation capacity varies over time because units that become certified for regulation may then be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources are eligible to offer regulation. Demand resources have an LOC of zero. No more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to "unavailable" for regulation for the day, or for a specific hour or set of hours and also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. All regulation offers are summed to calculate the total daily regulation offered, a figure that changes each hour.

- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs synchronized reserve and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria: a.) Daily or hourly unavailable units; b.) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or it has self-scheduled regulation); c.) Units which are assigned synchronized reserve; and d.) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or it has self-scheduled regulation), or units that are offline (except combustion turbine units).

  Even after SPREGO has run and selected units for regulation, PJM dispatchers can deselect units from SPREGO for other reasons including: to control transmission constraints; to avoid overgeneration during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.

  For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation offer cost and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. The Regulation and Synchronized Reserve Markets are cleared simultaneously and cooptimized with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, inter-area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

- **Cleared Regulation.** Units that are assigned regulation and synchronized reserve are expected to provide regulation and synchronized reserve for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reliability reasons.

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Appendix G provides examples of topics related to Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs):

- The sources of total congestion revenue and the determination of FTR target allocations and congestion receipts;

- The procedure for prorating ARRs when transmission capability limits the number of ARRs that can be allocated; and

- The establishment of ARR target allocations and credits through the Annual FTR Auction.

FTR Target Allocations and Congestion Revenue

Table G-1 shows an example of the sources of total congestion revenue and the determination of FTR target allocations and congestion receipts.

Table G-1 Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Day-Ahead Congestion Revenue						
Pricing Node	Day-Ahead LMP	Day-Ahead Load	Load Payments	Day-Ahead Generation	Generation Credits	Transmission Congestion Charges
A	$10	0	$0	100	$1,000	($1,000)
B	$15	50	$750	0	$0	$750
C	$20	50	$1,000	100	$2,000	($1,000)
D	$25	50	$1,250	0	$0	$1,250
E	$30	50	$1,500	0	$0	$1,500
Total		200	$4,500	200	$3,000	$1,500
Balancing Congestion Revenue						
Pricing Node	Real-Time LMP	Load Deviation	Load Payments	Generation Deviation	Generation Credits	Transmission Congestion Charges
A	$8	0	$0	0	$0	$0
B	$18	0	$0	0	$0	$0
C	$25	3	$75	5	$125	($50)
D	$20	(5)	($100)	0	$0	($100)
E	$40	7	$280	0	$0	$280
Total		5	$255	5	$125	$130
Transmission Congestion Charges Accounting						
Balancing Transmission Congestion Charges						$130
+Day-Ahead Transmission Congestion Charges						$1,500
=Total Transmission Congestion Charges						$1,630
FTR Target Allocations						
Path	Day-Ahead Path Price	FTR MW	FTR Target Allocations	Positive FTR Target Allocations	Negative FTR Target Allocations	
A-C	$10	50	$500	$500	$0	
A-D	$15	50	$750	$750	$0	
D-B	($10)	25	($250)	$0	($250)	
B-E	$15	50	$750	$750	$0	
Total		175	$1,750	$2,000	($250)	
Congestion Accounting						
Transmission Congestion Charges						$1,630
+Negative FTR Target Allocations						$250
=Total Congestion Charges						$1,880
Positive FTR Target Allocations				$2,000		
-FTR Congestion Credits				$1,880		
=Congestion Credit Deficiency				$120		
FTR Payout Ratio				0.94		

ARR Prorating Procedure

Table G-2 shows an example of the prorating procedure for ARRs. If line A-B has a 100 MW rating, but ARR requests from two customers together would impose 175 MW of flow on it, the service request would exceed its capability by 75 MW. The first customer's ARR request (ARR #1) is for a total of 300 MW with a 0.50 impact on the constrained line. It would thus impose 150 MW of flow on the line. The second customer's request (ARR #2) is for a total of 100 MW with a 0.25 impact and would impose an additional 25 MW on the constrained line.

Table G-2 ARR allocation prorating procedure: Illustration

Line A-B Rating = 100 MW						
ARR #	Path	Per MW Effect on Line A-B	Requested ARRs	Resulting Line A-B Flow	Prorated ARRs	Prorated Line A-B Flow
1	C-D	0.50	300	150	150	75
2	E-F	0.25	100	25	100	25
Total			400	175	250	100

Equation G-1 Calculation of prorated ARRs

Individual pro rata MW = (Line capability) • (Individual requested MW / Total requested MW) • (1 / per MW effect on line)

The equation would then be solved for each request as follows:

ARR #1 pro rata MW award = (100 MW) • (300 MW / 400 MW) • (1 / 0.50) = 150 MW

ARR #2 pro rata MW award = (100 MW) • (100 MW / 400 MW) • (1 / 0.25) = 100 MW

Together the prorated, awarded ARRs would impose a flow equal to line A-B's capability (150 MW • 0.50 + 100 MW • 0.25 = 100 MW).

ARR Credit

Table G-3 shows an example of how ARR target allocations are established, how FTR auction revenue is generated and how ARR credits are determined. The purchasers of FTRs pay and the holders of ARRs are paid based on cleared nodal prices from the Annual FTR Auction. If total revenue from the auction is greater than the sum of the ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies occurring in the hourly Day-Ahead Energy Market.

Table G-3 ARR credits: Illustration

Path	Annual FTR Auction Path Price	ARR MW	ARR Target Allocation	FTR MW	FTR Auction Revenue	ARR Credits
A-C	$10	10	$100	10	$100	$100
A-D	$15	10	$150	5	$75	$150
B-D	$10	0	$0	20	$200	$0
B-E	$15	10	$150	5	$75	$150
Total		30	$400	40	$450	$400
ARR Payout Ratio = ARR Credits / ARR Target Allocations = $400 / $400 = 100%						
Surplus ARR Revenue = FTR Auction Revenue - ARR Credits = $450 - $400 = $50						

APPENDIX H – CALCULATING LOCATIONAL MARGINAL PRICE

In order to understand the relevance of various measures of locational marginal price (LMP), it is important to understand exactly how average LMPs are calculated across time and across buses. This Appendix explains how PJM calculates average LMP and load-weighted LMP for the system, for a zone and, by extension, for any aggregation of buses, for an hour, for a day and for a year.

Hourly Integrated LMP and Hourly Integrated Load

In PJM a real-time LMP is calculated at every bus in every five-minute interval.

The five-minute system LMP is the load-weighted, system average LMP for that five-minute interval, calculated using the five-minute LMP at each load bus and the corresponding five-minute load at each load bus in the system. The sum of the product of the five-minute LMP and five-minute load at each bus, divided by the sum of the five-minute loads across the buses equal the load-weighted, system LMP for that five-minute interval.

In PJM, the hourly LMP at a bus is equal to the simple average of the 12 five-minute interval LMPs in the hour at that bus. This is termed the hourly integrated LMP at the bus. The hourly load at a bus is also calculated as the simple average of the 12 five-minute interval loads in the hour at that bus. This is termed the hourly integrated load at the bus. The hourly values are the basis of PJM's settlement calculations.

Load-Weighted LMP

The load-weighted, system LMP for an hour is equal to the sum of the product of the hourly integrated bus LMP for each load bus and the hourly integrated load for each load bus, for the hour, divided by the sum of the hourly integrated bus loads for the hour.

The load-weighted, zonal LMP for an hour is equal to the sum of the product of the hourly integrated bus LMP for each load bus in the zone and the hourly integrated load for each load bus in the zone, divided by the sum of the hourly integrated loads for each load bus in the zone.

The daily load-weighted, system LMP is equal to the product of the hourly integrated LMP for each load bus and the hourly integrated load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads for the system for the day.

The daily load-weighted, zonal LMP is equal to the product of each of the hourly integrated LMP for each load bus in the zone and the hourly integrated load for each load bus in the zone, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in the zone for the day.

The load-weighted, system LMP for a year is equal to the product of the hourly integrated LMP and hourly integrated load for each load bus, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in the system for each hour in the year.

The load-weighted, zonal LMP for a year is equal to the product of each of the hourly integrated bus LMP and hourly integrated load for each load bus in the zone, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in the zone for each hour in the year.

Equation H-1 LMP calculations

		i = 5 minute interval	h = 12 intervals = hour i = 1..12	d = 24 hours = day h=1..24	y = 365 days = 8760 hours = year d = 1..365
Bus	Simple Average	LMP_{bi}	$LMP_{bh}=\frac{\sum_{i=1}^{12} LMP_{bi}}{12}$	$LMP_{bd}=\sum_{h=1}^{24}\frac{LMP_{bh}}{24}$	$LMP_{by}=\sum_{h=1}^{8760}\frac{LMP_{bh}}{8760}$
Bus	Load Weighted Average			$lwLMP_{bd}=\frac{\sum_{h=1}^{24}(LMP_{bh}\cdot Load_{bh})}{\sum_{h=1}^{24} Load_{bh}}$	$lwLMP_{by}=\frac{\sum_{h=1}^{8760}(LMP_{bh}\cdot Load_{bh})}{\sum_{h=1}^{8760} Load_{bh}}$
System	Simple Average	$LMP_{si}=\frac{\sum_{b=1}^{B} LMP_{bi}}{B}$	$LMP_{sh}=\frac{\sum_{b=1}^{B} LMP_{bh}}{B}$	$LMP_{sd}=\frac{\sum_{h=1}^{24}\frac{\sum_{b=1}^{B} LMP_{bh}\cdot Load_{bh}}{\sum_{b=1}^{B} Load_{bh}}}{24}$	$LMP_{sy}=\frac{\sum_{h=1}^{8760}\frac{\sum_{b=1}^{B} LMP_{bh}\cdot Load_{bh}}{\sum_{b=1}^{B} Load_{bh}}}{8760}$
System	Load Weighted Average	$lwLMP_{si}=\frac{\sum_{b=1}^{B}(LMP_{bi}\cdot Load_{bi})}{\sum_{b=1}^{B} Load_{bi}}$	$lwLMP_{sh}=\frac{\sum_{b=1}^{B}(LMP_{bh}\cdot Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sd}=\frac{\sum_{h=1}^{24}\sum_{b=1}^{B}(LMP_{bh}\cdot Load_{bh})}{\sum_{h=1}^{24}\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sy}=\frac{\sum_{h=1}^{8760}\sum_{b=1}^{B}(LMP_{bh}\cdot Load_{bh})}{\sum_{h=1}^{8760}\sum_{b=1}^{B} Load_{bh}}$

APPENDIX I – GENERATOR SENSITIVITY FACTORS

Sensitivity factors define the impact of each marginal unit on locational marginal price (LMP) at every bus on the system.[1] The recent availability of sensitivity factor data permits the refinement of analyses in areas where the goal is to calculate the impact of unit characteristics or behavior on LMP.[2] This includes the impact on LMP of unit markups, frequently mitigated unit adders, unit markups by exempt units, the cost of various fuel types and the cost of emissions allowances.[3]

Generator sensitivity factors, or unit participation factors (UPFs), are calculated within the least-cost, security-constrained optimization program. For every five-minute system solution, UPFs describe the incremental amount of output that would have to be provided by each of the current set of marginal units to meet the next increment of load at a specified bus while maintaining total system energy balance. A UPF is calculated from each marginal unit to each load bus in an interval. In the absence of marginal losses, the sum of the UPFs associated with the set of marginal units in any given interval, for a particular load bus, will always sum to 1.0. UPFs can be either positive or negative. A negative UPF for a unit with respect to a specific load bus indicates that the unit would have to be backed down for the system to meet the incremental load at the load bus.

Within the context of a security-constrained, least-cost dispatch solution for an interval, where the LMP at the marginal unit's bus equals the marginal unit's offer, consistent with its output level, LMP at each load bus is equal to each marginal unit's UPF, relative to that load bus, multiplied by its offer price. The markup is defined as the difference between the price from the price-based offer curve and the cost from the cost-based offer curve. 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 is defined as the "constrained off" component. In addition, final LMPs calculated using UPFs may differ slightly from PJM posted LMPs as a result of rounding and missing data. This differential is identified as "NA."

1 For another review of sensitivity factors, please refer to "PJM 101: The Basics" (September 14, 2006), p. 107 <http://www.pjm.com/ services/courses/downloads/the-basics-part-01.pdf> (6.41 MB).

2 The PJM Market Monitoring Unit (MMU) identified applications for sensitivity factors and began to save sensitivity factors in 2006.

3 In prior state of the market reports, the impact of each marginal unit on load and LMP was based on an engineering estimate when there were multiple marginal units.

Table I-1 below shows the relationship between marginal generator offers and the LMP at a specific load bus X in a given five-minute interval.

Table I-1 LMP at bus X

Generator	UPF Bus X	Offer	Generator Contribution to LMP at X	Generator percentage contribution to LMP at X
A	0.5	$200.00	$100.00	0.85
B	0.4	$40.00	$16.00	0.14
C	0.1	$10.00	$1.00	0.01
			LMP at X	
			$117.00	1.00

As shown in Table I-1, three marginal generators at three different buses (A, B and C) have an effect on the LMP at load bus X. Each generator's effect on LMP at X is measured by the UPF of that unit with respect to X. The UPF for generator A is 0.5 relative to load bus X. That means that 50 percent of marginal Unit A's offer price will contribute directly to the LMP at X. Since A has an offer price of $200, generator A contributes $100, or UPF times the offer, to the LMP at load bus X. The UPFs from all the marginal units to the load bus must sum to 1.0, so that the marginal units explain 100 percent of the load bus LMP. Generators B and C have UPFs of 0.4 and 0.1, respectively, and offer prices of $40 and $10, respectively, and therefore contribute $16 and $1, respectively, to the LMP at X. Together, the marginal units' offers multiplied by their UPFs with respect to load bus X explain the interval LMP at the load bus.

Hourly Integrated LMP Using UPF

The presentation above shows the relationship between LMP and UPFs for a five-minute interval. Since PJM charges loads and credits generators on the basis of hourly integrated LMP, the relationship among marginal unit offers, UPFs and the hourly integrated LMP must be specified.

The relevant variables and notation are defined as follows:

h = hour

i = five-minute interval

t = year, where t designates the current year and t-1 designates the previous year

b = a specified load bus, where b ranges from 1 to B.

g = a specified marginal generator, where g ranges from 1 to G.

L = interval-specific load

Equation I-1 Hourly integrated load at a bus

The hourly integrated load at a bus is the simple average of the 12 interval loads at a bus in a given hour:

$$Load_{bh} = \frac{\sum_{i=1}^{12} L_{bi}}{12}$$

Equation I-2 Load bus LMP

Load bus LMPs are determined on a five-minute basis and are a function of marginal unit offers and UPFs in that interval:

$$LMP_{bi} = \sum_{g=1}^{G} \left(offer_{gi} \bullet UPF_{gbi}\right)$$

Equation I-3 Hourly integrated LMP at a bus

The hourly integrated LMP at a bus is the simple average of the 12 interval LMPs at a bus in a given hour:

$$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}$$

Equation I-4 Hourly total system cost

Total cost (TC) of the system in the hour is equal to the product of the hourly integrated LMP and the hourly integrated load at each bus summed across all buses in the hour:

$$TC_{h} = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh}\right)$$

Equation I-5 Hourly load-weighted LMP

System, load-weighted LMP for the hour is equal to the total hourly system cost (TC) divided by the sum of the bus's simple 12 interval average loads in the hour.

$$\mathrm{LMPSYS}_h = \frac{\mathrm{TC}_h}{\sum_{b=1}^{B} \mathrm{Load}_{bh}}$$

Equation I-6 System average annual load-weighted LMP

The load-weighted (LW), average system (S) LMP for the year:

$$\mathrm{Annual\_SLW\_LMP} = \sum_{h=1}^{8760} \frac{\mathrm{TC}_h}{\sum_{b=1}^{B} \mathrm{Load}_{bh}}$$

Hourly Integrated Markup Effects Using UPFs

UPFs can be used to accurately calculate the markup component of LMP by individual marginal units at any individual load bus, on the LMP at any aggregation of load buses and thus on the system LMP. The markup component of LMP resulting from the markup behavior of marginal units on the system price is a measure of market power (market performance). The markup component of LMP is based on the markup of the actual marginal units and is not based on a redispatch of the system using cost-based offers.

To determine the effect of marginal unit markup on system LMP on an hourly integrated basis, the following steps are required.

Equation I-7 UPF based hourly total system cost

Total cost (TC) of the system in the hour is equal to the product of the simple average LMP and the simple average load at each bus summed across all buses in the hour which, using the definitions above, can be expressed in terms of marginal unit offers and UPFs:

$$\mathrm{TC}_h = \sum_{b=1}^{B} \mathrm{LMP}_{bh} \bullet \mathrm{Load}_{bh} = \sum_{b=1}^{B} \left[\mathrm{Load}_{bh} \bullet \frac{\left[\sum_{i=1}^{12} \sum_{g=1}^{G} \left(\mathrm{offer}_{gi} \bullet \mathrm{UPF}_{gbi} \right) \right]}{12} \right]$$

Equation I-8 System, load-weighted LMP

System, load-weighted LMP for the hour is equal to total hourly system cost divided by the sum of the bus's simple 12 interval average loads in the hour.

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(offer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Equation I-9 Cost-based offer system, hourly load-weighted LMP

Holding dispatch and marginal units constant, the system, hourly load-weighted LMP based on cost offers of the marginal units is found by substituting the marginal unit cost offers into the LMPSYS formula above:

$$LMPSYSCost_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(CostOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Equation I-10 Impact of marginal unit markup on LMP

The marginal unit markups contribution to system LMP for the hour is:

$Mark\_Up = LMPSYS_h - LMPSYSCost_h$

UPF–Weighted, Marginal Unit Markup

Equation I-11 Price-cost markup index

The price-cost markup index for a marginal unit provides a generator conduct or behavior measure of market power:

$$MarkUp_{gi} = \frac{\left(Offer_{gi} - CostOffer_{gi}\right)}{Offer_{gi}}$$

Equation I-12 UPF load-weighted, marginal unit markup

The UPF load-weighted, marginal unit markup (measure of unit conduct) provides a measure of market power for a given hour. This measure reflects the weighted-average markup index for marginal units (conduct or behavior):

$$lwMarkUp_{sh} = \frac{\sum_{b=1}^{B}\left[\frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(MarkUp_{gi} \bullet UPF_{gbi}\right)}{12} \bullet Load_{bh}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Hourly Integrated Load-Weighted, Historical, Cost-Adjusted LMP Using UPFs

UPFs can be used to calculate load-weighted, historical, cost-adjusted LMP for a specific time period. This method is used to disaggregate the various sources of LMP, including all the components of unit marginal cost and unit markup, and to calculate the contributions of each source to changes in system LMP.

The extent to which changes in fuel costs, emission allowance costs, variable operation and maintenance costs (VOM) and markup affect the offers of marginal units depends on the share of each component of the offers. Changes in cost between specified time periods affect only the portion of the unit's offer related to the specified cost. The percentage of a unit's offer that is based on each of the components is given as the following:

Fuel:	$\%Fuel_{gi}$
SO_2:	$\%SO_{2\,gi}$
NO_X:	$\%NO_{X\,gi}$
VOM:	$\%VOM_{gi}$
Markup:	$\%Mark\text{-}Up_{gi}$

Note that the proportion of specific components of unit offers are calculated on an interval and unit-specific basis.

Cost components are determined for each marginal unit for the relevant time periods:

Delivered fuel cost per MWh: FC_{gt}.

Sulfur dioxide emission-related cost per MWh: SO_{2gt}.

Nitrogen oxide emission-related cost per MWh: NO_{xgt}.

Fuel costs (FC) are specific to the unit's location, the unit's fuel type and the time period in question. For example:

FC_{gt}=Avg Fuel Cost in specified "Current Year's Period" (ex, April 1st of 2006)

FC_{gt-1}=Avg Fuel Cost in specified "Previous Year's Period" (ex, April 1st of 2005)

Fuel-Cost-Adjusted LMP

The portion of a marginal generator's offer that is related to fuel costs for a specified period is adjusted to reflect the previous period's fuel costs.

Equation I-13 Fuel-cost-adjusted offer

Subtracting the proportional fuel cost adjustment from the marginal generator's interval-specific offer provides the fuel-cost-adjusted offer (FCA):

$$FCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \frac{\left(FC_{gt} - FC_{gt-1}\right)}{FC_{gt}} \right]$$

Equation I-14 Fuel-cost-adjusted, load-weighted LMP

Using $FCAOffer_{gi}$ for all marginal units in place of the unadjusted offers ($offer_{gi}$) in Equation I-8 (the system, load-weighted LMP equation) results in the hourly fuel-cost-adjusted, load-weighted LMP:

$$LWFCAsysLMP_h = \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(FCAoffer_{gi} \bullet UPF_{gbi}\right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}$$

Equation I-15 Annual systemwide, fuel-cost-adjusted, load-weighted LMP

The annual systemwide, fuel-cost-adjusted, load-weighted (SFCALW) LMP for the year is given by the following equation:

$$\text{Annual\_SFCALW\_LMP} = \sum_{h=1}^{8760} \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}}$$

Cost-Adjusted LMP

Equation I-16 Unit historical, cost-adjusted offer

Summing the unit's specific historic cost-adjusted component effects and subtracting that sum from the unit's unadjusted offer provides the historical, cost-adjusted offer of the unit (HCAOffer):

$$HCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}}\right) - \%NOx_{gi} \bullet \left(\frac{NOx_{gt} - NOx_{gt-1}}{NOx_{gt}}\right) - \%SO2_{gi} \bullet \left(\frac{SO2_{gt} - SO2_{gt-1}}{SO2_{gt}}\right)\right]$$

Equation I-17 Unit historical, cost-adjusted, load-weighted LMP

Using each unit's $HCAOffer_{gi}$ in place of its unadjusted offers ($offer_{gi}$) in Equation I-8 (the system, load-weighted LMP equation) results in the following historical, cost-adjusted, load-weighted LMP for the hour in question:

$$LWHCAsysLMP_h = \frac{TCHCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(HCAOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Equation I-18 Systemwide, historical, cost-adjusted, load-weighted LMP

The annual systemwide, historical, cost-adjusted, load-weighted (annual SHCALW) LMP for the year is given by the following equation:

$$\text{Annual\_SHCALW\_LMP} = \sum_{h=1}^{8760} \frac{\text{TCHCA}_h}{\sum_{b=1}^{B} \text{Load}_{bh}}$$

APPENDIX J – THREE PIVOTAL SUPPLIER TEST

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 the PJM markets. One of the Market Monitoring Unit's (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 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.

The structural test for suspending offer capping set forth in the PJM Amended and Restated Operating Agreement (OA) Schedule 1, Sections 6.4.1(e) and (f) is 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 for any constraint not exempt from offer capping. The three pivotal supplier test defined in the OA represents a significant evolution in accuracy because the current application of the test uses real-time data and tests constraints as they actually arise with all the actual system features that exist at the time including transmission constraints, load and generator availability.

As a result of PJM's implementation of the three pivotal supplier test in real time, the actual competitive conditions associated with each binding constraint are analyzed in real time as they arise. The three pivotal supplier test replaced the prior approach which was to offer cap all units required to resolve a binding constraint. The application of the three pivotal supplier test has meant a reduction in the application of offer capping to unit owners. As a result of the application of the three pivotal supplier test, offer capping is applied only at times when the local market structure is not competitive and only to those participants with structural market power.

Three Pivotal Supplier Test: Background

By order issued April 18, 2005, the United States Federal Energy Regulatory Commission (FERC) set for hearing, in Docket No. EL04-121-000, PJM's proposal: (a) to exempt the AP South Interface from PJM's offer-capping rules; and (b) to conduct annual competitive analyses to determine whether additional exemptions from offer capping are warranted.

By order issued July 5, 2005, the FERC also set for hearing, in Docket No. EL03-236-006, PJM's three pivotal supplier test. The Commission further set for hearing issues related to the appropriateness of implementing scarcity pricing in PJM. In the July order, the Commission consolidated Docket No. EL04-121-000 and Docket No. EL03-236-006.

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

On November 16, 2005, PJM filed a "Settlement Agreement" resolving all issues set for hearing in the two section 206 proceedings established by the Commission to address certain aspects of PJM's market power mitigation rules, including the application of the three pivotal supplier test, provisions for scarcity pricing, offer caps for frequently mitigated units and competitive issues associated with certain of PJM's internal interfaces. On December 20, 2005, the presiding administrative law judge certified the "Settlement Agreement" to the Commission as uncontested. On January 27, 2006, in Docket Nos. EL03-236-006, EL04-121-000, 001 and 002, the Commission ordered that the "Settlement Agreement," including the amendments to the PJM Tariff and its OA, was in the public interest and was thereby approved and accepted for filing and made effective as set forth in the "Settlement Agreement."[2]

Market Structure Tests and Market Power Mitigation: Core Concepts

A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets where competitive forces are adequate. The three pivotal supplier test for local market power is a reasonable application of the logic contained in the Commission's market power tests.

The Commission adopted market power screens and tests in the AEP Order.[3] The AEP Order defined two indicative screens and the more dispositive delivered price test. The Commission's delivered price test for market power defines the relevant market as all suppliers who offer at or below the clearing price times 1.05 and using that definition, applies pivotal supplier, market share and market concentration analyses. These tests are failed if the supplier in question is pivotal, has a market share in excess of 20 percent or if the Herfindahl-Hirschman Index (HHI) in the relevant market exceeds 2500. A supplier is pivotal under the screen if it is pivotal in the relevant market as defined by the delivered price test. The Commission also recognized that there are interactions among the results of each screen under the delivered price test and that some interpretation is required and, in fact, is encouraged.[4]

The three pivotal supplier test, as implemented, is consistent with the Commission'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 includes more competitors in its definition of the relevant market than the delivered price test. While the delivered price test defines the relevant market to include all offers with costs less than or equal to 1.05 times the market price, the three pivotal supplier test includes all offers with costs less than or equal to 1.50 times the clearing price for the local market.

The goal of defining the relevant market is to determine those units that are actual competitors to the units that clear in a market. The Commission definition would indicate, if the marginal unit set the clearing price

2 114 FERC ¶ 61,076 (2006).

3 107 FERC ¶ 61,018 (2004) (AEP Order).

4 107 FERC ¶ 61,018 (2004).

based on an offer of $200 per MWh, that all units with costs less than or equal to $210 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier definition would indicate that, if the marginal unit set the clearing price based on an offer of $200 per MWh, that all units with costs less than or equal to $300 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. Clearly, the three pivotal supplier test incorporates a definition of meaningful competitors that is at the high end of inclusive. It is certainly questionable whether a $300 offer meaningfully constrains the offer of a $200 unit. This broad market definition is combined with the recognition that multiple owners can be meaningfully jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

The three pivotal supplier test is also consistent with the delivered price test in that it tests for the interaction between individual participant attributes and features of the relevant market structure. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action, based on economic theory, which accounts simultaneously for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it. A market share in excess of 20 percent does not matter if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not matter if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. Similarly, an HHI in excess of 2500 does not matter if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not matter if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[5]

The three pivotal supplier test was designed in light of actual elasticity conditions in load pockets in wholesale power markets in PJM. The price elasticity of demand is probably the most critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, “In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives.”[6] The Commission also stated:

5 For detailed examples, see Joseph E. Bowring, PJM Market Monitor, “MMU Analysis of Combined Regulation Market,” PJM Market Implementation Committee Meeting (December 20, 2006).

6 107 FERC ¶ 61,018 (2004).

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response.[7]

The three pivotal supplier test is a reasonable application of the Commission's delivered price test to the case of load pockets that arise in a market based on security-constrained, economic dispatch with locational market pricing and extremely inelastic demand. The three pivotal supplier test also exists in the context of a local market power mitigation rule that relies on a structure test, a participant behavior test and a market impact test. The three pivotal supplier test explicitly incorporates the relationship between supply and demand in the definition of pivotal and it provides a clear test for whether excess supply is adequate to offset other structural features of the market and result in an adequately competitive market structure. The greater the supply relative to demand, the less likely that three suppliers will be jointly pivotal, all else equal.

The three pivotal supplier test represents a significant modification of the previously existing PJM local market power rule, which did not include an explicit market structure test. The goal of the applying a market structure test is to continue to limit the exercise of market power by generation owners in load pockets but to lift offer capping when the exercise of market power is unlikely. The goal of the three pivotal supplier test, proposed by PJM, was not to weaken the local market power rules but to make them more flexible by adding an explicit market structure test. As recognized by PJM when the local market power rule was proposed in 1997 and has continued to be the case, the local markets created by transmission constraints are generally not structurally competitive. Nonetheless, it is appropriate to have a clear test as to when a local market is adequately competitive to permit the relaxation of local market power mitigation. The three pivotal supplier test proposed by PJM is not a guarantee that suppliers will behave in a competitive manner in load pockets. The three pivotal supplier test is a structural test that is not a perfect predictor of actual behavior. The existence of this risk is the reason that the PJM Tariff language also includes the ability of the MMU to request that the Commission reinstate offer caps in cases where there is not a competitive outcome.

Three Pivotal Supplier Test: Mechanics

The three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are the demand and the supply. The demand consists of the incremental, effective MW required to relieve the constraint. Total supply consists of all effective MW of supply incrementally available to relieve the constraint at a distribution factor (DFAX) greater than or equal to the DFAX used by PJM in operations.[8] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the

7 107 FERC ¶ 61,018 (2004).

8 A unit's contribution towards a supplier's effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, to the extent that the capacity in question can be made available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of .05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of .5 to the constraint would be 25 MW.

assets in question. Generation capacity controlled directly or indirectly through affiliates or contracts with third parties are attributed to a single supplier.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (S) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective MW of supply, as shown in Equation J-1, and the clearing price (P_c) is defined as shown in Equation J-2.

Equation J-1 Incremental effective MW of supply

$$MW \cdot DFAX$$

Equation J-2 Price of clearing offer

$$P_c = \frac{Offer_c - SMP}{DFAX_c}$$

To be relevant, the effective offer of incremental supplier i must be less than or equal to 1.5 times P_c:

Equation J-3 Relevant and effective offer

$$P_{ie} = \frac{Offer_i}{DFAX_i} \leq 1.5 \cdot P_c$$

Where the relevant, effective incremental supply of supplier i is a function of price:

Equation J-4 Relevant and effective supply of supplier i

$$S_i = MW\left(P_{ie}\right) \cdot DFAX_i$$

Where, S_i is the relevant effective supply (relevant, incremental and effective supply) of supplier i, total relevant effective supply (total relevant, incremental and effective supply) for suppliers i=1 to n is shown in Equation J-5.

Equation J-5 Total relevant, effective supply

$$S = \sum_{i=1}^{n} S_i$$

Each effective supplier, from 1 to n, is ranked, from largest to smallest relevant effective supply, relative to the constraint for which it is being tested. In the first iteration of the test, the two largest suppliers are combined with the third largest supplier, and this combined supply is subtracted from total relevant effective supply, described above. The resulting amount of net relevant effective supply is divided by the total relief required (D). Where j defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with j=3), Equation J-6 shows the formula for the three pivotal supplier metric, the three pivotal residual supplier index (RSI3).

Equation J-6 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n} (S_i) - \sum_{i=1}^{2} (S_i) - S_j}{D}$$

Where j=3, if $RSI3_j$ is less than, or equal to, 1.0, the three largest suppliers in the market for the relief of the constraint fail the three pivotal supplier test. That is, the three largest suppliers are jointly pivotal for the local market created by the need to relieve the constraint using local, out of merit units. If $RSI3_j$ is greater than 1.0, the three largest potential suppliers of relief MW pass the test and the remaining suppliers (j=4..n) pass the test. In the event of a failure of the three largest suppliers, further iterations of the test are needed, with each subsequent iteration testing a subsequently smaller supplier (j=4..n) in combination with the two largest suppliers. In each iteration, when $RSI3_j$ is less than 1.0, it indicates that the tested supplier, in combination with the two largest suppliers, has failed the test. Iterations of the test continue until the combination of the two largest suppliers and a supplier j achieve a result of $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers will pass the test.

If a supplier fails the test for a constraint, units that are part of a supplier's relevant effective supply with respect to a constraint can have their offers capped at cost plus 10 percent, or cost plus relevant adders for frequently mitigated units and associated units. However, capping only occurs to the extent that the units of this supplier's relevant, effective supply are offered at greater than cost plus 10 percent and are actually dispatched to contribute to the relief of the constraint in question.

APPENDIX K – GLOSSARY

Active load management (ALM)	Retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. ALM derives an ALM credit in the accounted-for-obligation.
Aggregate	Combination of buses or bus prices.
Ancillary service	Those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Ancillary service area	A defined market service area for ancillary services including regulation and synchronized reserve.
Area control error (ACE)	Area control error (ACE) is a real-time metric used by PJM operators to measure the imbalance between load and generation. ACE is the instantaneous MW imbalance between generation and load plus net interchange.
Associated unit (AU)	A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic generation control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly unweighted LMP	An LMP calculated by averaging hourly LMP with equal hourly weights.
Balancing Energy Market	Energy that is generated and financially settled during real time.
Basic generation service (BGS)	The default electric generation service provided by the electric public utility to consumers who do not elect to buy electricity from a third-party supplier.

Bilateral agreement	An agreement between two parties for the sale and delivery of a service.
Black start unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the transmission system.
Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity credit	An entitlement to a specified number of MW of unforced capacity from a capacity resource for the purpose of satisfying capacity obligations imposed under the Reliability Assurance Agreement (RAA).
Capacity deficiency rate (CDR)	The capacity deficiency rate is based on the annual carrying charges for a new combustion turbine, installed and connected to the transmission system. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Market	All markets where PJM members can trade capacity.
Capacity queue	A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.
Combined cycle (CC)	A generating unit generally consisting of one or more gas-fired turbines and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover.
Control zone	An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.
Decrement bids (DEC)	Financial bid to purchase a defined MW level of energy up to a specified LMP, above which the bid is zero.

Dispatch rate	Control signal, expressed in dollars per MWh, calculated by PJM and transmitted continuously and dynamically to generating units to direct the output level of all generation resources dispatched by PJM.
Disturbance control standard	A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.
Eastern Prevailing Time (EPT)	Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.
Economic generation	Units producing energy at an offer price less than, or equal to, LMP.
End-use customer	Any customer purchasing electricity at retail.
Equivalent availability factor (EAF)	The equivalent availability factor is the proportion of hours in a year that a unit is available to generate at full capacity.
Equivalent demand forced outage rate	The equivalent demand forced outage rate
(EFORd)	(EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate.
Equivalent forced outage factor (EFOF)	The equivalent forced outage factor is the proportion of hours in a year that a unit is unavailable because of forced outages.
Equivalent maintenance outage factor	The equivalent maintenance outage factor is
(EMOF)	the proportion of hours in a year that a unit is unavailable because of maintenance outages.
Equivalent planned outage factor (EPOF)	The equivalent planned outage factor is the proportion of hours in a year that a unit is unavailable because of planned outages.
External resource	A resource located outside metered PJM boundaries.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm point-to-point transmission	Firm transmission service that is reserved and/or scheduled between specified points of receipt and delivery.

Firm transmission	Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is, however, subject to an emergency, an unanticipated failure of a facility or other event.
Fixed-demand bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Frequently mitigated unit (FMU)	A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.
Generation offers	Schedules of MW offered and the corresponding offer price.
Generator owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.
Gross deficiency	The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as accounted-for deficiency.
Gross excess	The amount by which a load-serving entity's (LSE's) unforced capacity exceeds its accounted-for obligation. The term is referred to as "Accounted-for Excess" in "Manual 35: Definitions and Acronyms."
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz (Hz)	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger installed on combined-cycle generators.
Increment offers (INC)	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.

Initial threshold	In the context of the PJM economic planning process, when the cumulative gross congestion cost of a constraint exceeds the applicable initial threshold, PJM begins determining the extent to which the load affected by that constraint is unhedgeable. Initial threshold values are specific to the transmission level voltage of the affected facility.
Installed capacity	Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.
Interval Market	The Capacity Market rules provide for three Interval Markets, covering the months from January through May, June through September and October through December.
Load	Demand for electricity at a given time.
Load aggregator	An entity licensed to sell energy to retail customers located within the service territory of a local distribution company.
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.
Lost opportunity cost (LOC)	The difference in net compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received for providing energy output.
Marginal unit	The last generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met reasonable creditworthiness standards as established by PJM. Market buyers are otherwise able to make purchases and market sellers are otherwise able to make sales in the PJM Energy or Capacity Credit Markets.
Market threshold	In the context of the PJM economic planning process, each market threshold represents the level of unhedgeable congestion costs that triggers the start of a one-year "market window" for the development of market solutions to unhedgeable congestion. Market threshold values are specific to the transmission voltage of the affected facility.
Market user interface	A thin client application allowing generation marketers to provide and to view generation data, including bids, unit status and market results.

Market window	In the context of the PJM economic planning process, the period of time during which PJM allows for the development of market solutions to unhedgeable congestion associated with an affected facility.
Mean	The arithmetic average.
Median	The midpoint of data values. Half the values are above and half below the median.
Megawatt (MW)	A unit of power equal to 1,000 kilowatts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt-hour (MWh)	One MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Merchant solution	In the context of the PJM economic planning process, a solution proposed to reduce or to eliminate unhedgeable congestion on an affected facility.
Min gen	An emergency declaration for periods of light load.[1]
Monthly CCM	The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).
Multimonthly CCM	The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).
Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.
Net exchange (capacity)	Capacity imports less exports.
Net interchange (energy)	Gross import volume less gross export volume in MWh.
Non-economic generation	Units producing energy at an offer price greater than the LMP.
North American Electric Reliability Council	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.

1 See PJM "Manual 13: Emergency Operations," Section 2, pp. 43-48.

Obligation	The sum of all load-serving entities' unforced capacity obligations as determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.
Phase-in FTRs	FTRs directly allocated to eligible customers outside of the regularly scheduled FTR allocations when new control zones are integrated into PJM after the start of the current planning period. Phase-in FTRs remain in effect until the start of the next regularly scheduled FTR allocation.
PJM member	Any entity that has completed an application and satisfies the requirements of PJM to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Price duration curve	A graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Regional Transmission Expansion	The process by which PJM recommends
Planning (RTEP) Protocol	specific transmission facility enhancements and expansions based on reliability and economic criteria.
Selective catalytic reduction (SCR)	NOx reduction equipment usually installed on combined-cycle generators.

Self-scheduled generation	Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
Shadow price	The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.
Sources and sinks	Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.
Special protection scheme (SPS)	A load transfer relaying scheme intended to reduce the adverse post-contingency impact on a protected facility.
Spot Market	Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.
Standard deviation	A measure of data variability around the mean.
Static Var compensator	A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.
Synchronized reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities or by reducing the demand of demand resources. During system restoration, customer load may be classified as synchronized reserve.
System installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
System lambda	The cost to the PJM system of generating the next unit of output.

Temperature-humidity index (THI)	A temperature-humidity index (THI) gives a single, numerical value in the general range of 70 to 80, reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as follows: THI = Td – (0.55 – 0.55RH) * (Td - 58) where Td is the dry-bulb temperature and RH is the percentage of relative humidity.
Unforced capacity	Installed capacity adjusted by forced outage rates.
Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Zone	See "Control zone" (above).

APPENDIX L – LIST OF ACRONYMS

ACE	Area control error
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
AP	Allegheny Power Company
ARR	Auction Revenue Right
ASA	Ancillary service area
ATC	Available transfer capability
AU	Associated unit
BAAL	Balancing authority ACE limit
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
Btu	British thermal unit
CAISO	California Independent System Operator
C&I	Commercial and industrial customers
CC	Combined cycle
CCM	Capacity Credit Market

CDR	Capacity deficiency rate
CDTF	Cost Development Task Force
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CP	Pulverized coal-fired generator
CPL	Carolina Power & Light Company
CPS	Control performance standard
CSP	Curtailment service provider
CT	Combustion turbine
DAY	The Dayton Power & Light Company
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south

DSR	Demand-side response
DUK	Duke Energy Corp.
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EHV	Extra-high-voltage
EKPC	East Kentucky Power Cooperative, Inc.
EMOF	Equivalent maintenance outage factor
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPPL	Forecast period peak load
FPR	Forecast pool requirement

FTR	Financial Transmission Right
GCA	Generating control area
GE	General Electric Company
GWh	Gigawatt-hour
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
ICAP	Installed capacity
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection Service Agreement
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	Joint Operating Agreement
JRCA	Joint Reliability Coordination Agreement
LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area

LGEE	LG&E Energy, L.L.C.
LGIA	Large Generator Interconnection Agreement
LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
LTE	Long-term emergency
MAAC	Mid-Atlantic Area Council
MACRS	Modified accelerated cost recovery schedule
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MC	The PJM Members Committee
MCP	Market-clearing price
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MEW	Western subarea of Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MIL	Mandatory interruptible load
MMU	PJM Market Monitoring Unit
MP	Market participant
MUI	Market user interface

MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load
NO_x	Nitrogen oxides
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OPL	Obligation peak load
OVEC	Ohio Valley Electric Corporation
PAR	Phase angle regulator
PCS	Production cost study
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.

PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
PEPCO	Pepco (formerly Potomac Electric Power Company)
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area

PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point

PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak load contributions
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSN	PSEG north
PSNC	PSEG northcentral
QIL	Qualified interruptible load
RAA	Reliability Assurance Agreement among Load-Serving Entities
RECO	Rockland Electric Company zone
RMCP	Regulation market-clearing price
RPM	Reliability Pricing Model
RSI	Residual supply index
RSI_x	Residual supply index, using "x" pivotal suppliers
RTC	Real-time commitment

RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
SEPJM	Southeastern PJM subarea
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SPS	Special protection scheme
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
STE	Short-term emergency
SVC	Static Var compensator
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index

TLR	Transmission loading relief
TPS	Three pivotal supplier
TVA	Tennessee Valley Authority
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VOM	Variable operation and maintenance expense
WEC	Wisconsin Energy Corporation

APPENDIX M – ERRATA

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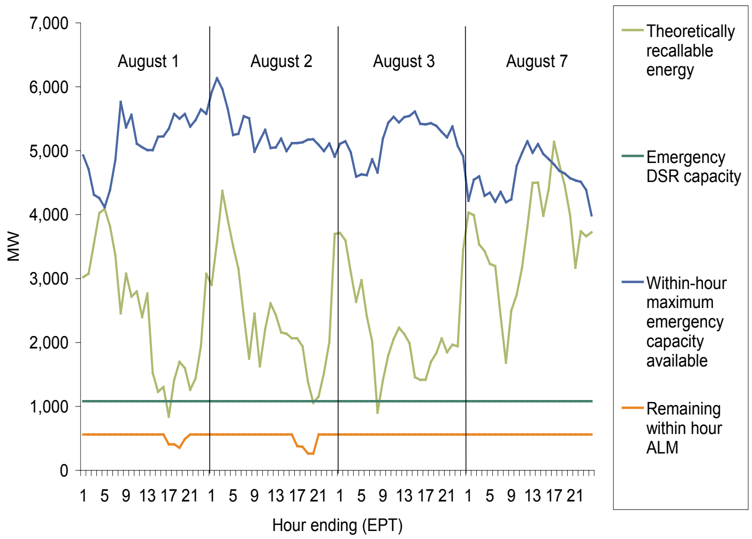
Figure 3-10 Within-hour emergency resources: August 1 to August 3, and August 7, 2006



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Operating Reserve Credits by Category

Figure 3-12 shows that the largest share of total operating reserve credits, 42.57 percent, was paid to resources in the Balancing Energy Market during 2006 and that 75.36 percent of total operating reserve credits were in the balancing category. Figure 3-12 also shows that 10.24 percent of total operating reserve credits were paid to resources in the Day-Ahead Energy Market and that 20.31 percent of total operating reserve credits were in the day-ahead category.[86]

Figure 3-12 Operating reserve credits: Calendar year 2006