2005 State of the Market Report

Market Monitoring Unit

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PREFACE

The Market Monitoring Unit of the 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 *2005 State of the Market Report* is the eighth such annual report. This report is submitted to the Board of PJM Interconnection pursuant to the PJM Open Access Transmission Tariff, Attachment M (Market Monitoring Plan):

> The Market Monitoring Unit shall prepare and submit to the PJM Board and, if appropriate, to the PJM Members Committee, periodic (and if required, ad hoc) reports on the state of competition within, and the efficiency of, the PJM Market.

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.[1]

1 96 FERC ¶61,061 (2001).

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INTRODUCTION

The PJM Interconnection operates a centrally dispatched, competitive wholesale electricity market comprising generating capacity of 163,471 megawatts (MW) and about 390 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] PJM grew substantially in 2005 as the result of the integrations of new members from parts of Virginia, North Carolina, Maryland and Pennsylvania.[2]

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 Spinning Reserve Market and the Annual and Monthly 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 Daily Capacity Markets on January 1, 1999, and 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 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.[3]

During the last two calendar years, PJM has 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. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[4]

- **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,[5] and the Allegheny Power Company (AP) Control Zone.[6]

- **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).[7]

1 See Appendix A, "PJM Service Territory," for map.

2 In 2004, PJM operated a centrally dispatched, competitive wholesale electricity market comprising generating capacity of approximately 144,000 megawatts (MW) and about 330 market buyers, sellers and traders of electricity in a region including more than 45.3 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

3 See also Appendix B, "PJM Market Milestones."

4 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

5 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

6 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 the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

7 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).

- **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.

Conclusions

This report assesses the competitiveness of the Markets managed by PJM during 2005, including market structure, participant behavior and market performance. This report was prepared by and reflects the analysis of PJM's independent Market Monitoring Unit (MMU).

The MMU concludes that in 2005:

- The Energy Market results were competitive;

- The PJM Capacity Market results were competitive;

- The Regulation Markets results were competitive both where market-based offers and cost-based offers set market prices;

- The Spinning Reserve Markets results were competitive (markets were cleared on cost-based offers); and

- The FTR Auction Market results were competitive.

The MMU also concludes:

- Market power in the Capacity Markets remains a serious concern given the structural issues of high levels of supplier concentration, frequent occurrences of pivotal suppliers and extreme inelasticity of demand. Market power remains endemic to the structure of PJM Capacity Markets. The reliability pricing model (RPM) proposal is a logical overall design to permit the benefits of competition in the Capacity Market in the context of smaller and less structurally competitive locational markets because, in addition to its other features, it explicitly includes market power mitigation rules;

- The Ancillary Service Markets in PJM are generally not structurally competitive, as they are characterized by various combinations of high levels of supplier concentration, high individual market shares, frequent occurrences of individual or jointly pivotal suppliers and inelastic demand. The actual operation of Ancillary Service Markets, including both cost-based and price-based offers and market-clearing prices, demonstrates that the benefits of competitive markets can be realized even when, for structural reasons, the offers of some or all participants are limited to a measure of cost; and

- Market structure issues in the PJM Energy Markets continue to be offset to date by a combination of high levels of supply, generally moderate demand, generators' obligations to serve load, local market power mitigation and competitive participant behavior.

Recommendations

The MMU recommends the retention of key market rules and certain enhancements to those rules that are required for continued competitive results in PJM Markets and for continued improvements in the functioning of PJM Markets. These include:

- Enhancements of the PJM Capacity Market design, generally consistent with PJM's RPM proposal, 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;

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

- Improvement of 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;

- Improvement in the analysis of the underlying sources of loop flows in order to enhance the efficient use of PJM market resources;

- Enhancement of PJM's posting of market data to promote market transparency;

- Modification of rules governing the reporting and verification of unit outages to ensure consistency with actual unit conditions, accurate assessments of system conditions and incentives for efficient market outcomes;

- Implementation of scarcity pricing rules that ensure competitive prices when scarcity conditions exist in market regions;

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

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

- 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; and

- Based on the experience of the MMU during its seventh 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 United States Federal Energy Regulatory Commission (FERC). The MMU recommends that the Market Monitoring Plan be modified consistent with these objectives.

Energy Market, Part 1

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of other transaction types. For PJM, 2005 was a time of growth with two control zones being integrated into PJM Markets. The PJM MMU's analysis of the Energy Market treats these new zones as parts of existing markets as of the date of integration.

The MMU analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2005, including market size, concentration, residual supply index, price-cost markup, net revenue and prices. The MMU concludes that, despite ongoing concerns about market structure, the PJM Day-Ahead and Real-Time Energy Market performance results were competitive in 2005.

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 MMU's primary goals is to identify actual or potential market design flaws.[8] 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.

8 PJM Market Monitoring Plan, OATT, Attachment M.

Overview

Market Structure

- **Supply.** During the June to September 2005 summer period, PJM Energy Markets received an average of 168,600 MW in net supply, including hydroelectric generation, excluding real-time imports or exports. The 2005 net supply represented an approximately 60,600 MW increase compared to the comparable 2004 summer period. The increase in 2005 was comprised of 39,000 MW from the Phase 3 AEP and DAY Control Zone integrations, 3,100 MW from the Phase 4 DLCO Control Area integration, 20,600 MW from the Phase 5 Dominion Control Zone integration, an average net increase of 200 MW of hydroelectric power generation and 2,300 MW from a net decrease in capacity from the Mid-Atlantic Region, the AP Control Zone and the ComEd Control Zone.

- **Demand.** The PJM system peak load in 2005 was 133,763 MW on July 26, 2005, a coincident summer peak load reflecting the Mid-Atlantic Region and the AP, ComEd, AEP, DAY, DLCO and Dominion Control Zones.[9] The PJM summer peak load in 2004 of 77,887 MW occurred prior to the integrations of the AEP, DAY, DLCO and Dominion Control Zones. If the 2004 summer peak load were adjusted to include the AEP, DAY, DLCO and Dominion zones for comparison purposes, the 2004 summer peak load of the combined area would have been 120,353 MW.[10]

- **Ownership 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. Specific geographic areas of PJM exhibited moderate to high levels of concentration when transmission constraints defined local markets. No evidence exists, however, that market power was exercised in these areas during 2005, both because of generator obligations to serve load and because of PJM's rules limiting the exercise of local market power.

- **Pivotal Suppliers.** A generation owner or group of generation owners is pivotal if the output of the owner's or owners' generation facilities is required in order to meet market demand. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The residual supply index (RSI) is a measure of the extent to which generation owners are pivotal suppliers. Like concentration ratios, the RSI is an indicator of market structure. When the RSI is less than 1.0, a generation owner or group of generation owners is pivotal. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.0 clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power. The RSI results are consistent with the conclusion that the PJM Energy Market results were competitive in both 2004 and 2005, with an average one pivotal RSI of 1.64 and 1.55, respectively. In 2005, a generation owner in the PJM Energy Market was pivotal for only 24 hours, less than 0.3 percent of all hours during the year. This represents an increase in pivotal hours

9 For the purpose of the *2005 State of the Market Report*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix H, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

10 This calculated 2004 peak load of the combined area was a total system coincident peak load and occurred on a different day and hour than the 2004 peak load for PJM.

from 2004, when a generation owner was pivotal in the Energy Market for eight hours, or less than 0.1 percent of all hours.

- **Ownership of Marginal Units.** The concentration of ownership of marginal units provides an additional dimension of the pivotal supplier results. The higher the level of concentration of ownership of marginal units the greater is the potential market power issue.

- **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 during the 11-month period ended November 30, 2005, were 2,065 MW from active load management, 1,619 MW from the Emergency Load-Response Program and 2,210 MW from the Economic Load-Response Program. There were 260 MW enrolled in both the Load-Response Program and in active load management. The 10,194 MW in total DSR resources, including additional programs reported by PJM customers in response to a survey, were approximately 8 percent of PJM's peak demand.

Market Conduct

- **Price-Cost Markup.** Price-cost markups are a measure of market power when they measure the impact of particular conduct on market outcomes. The price-cost markup reflects both participant conduct and the resultant market performance. The price-cost markup index is defined here as the difference between price and marginal cost, divided by price for the marginal units in the PJM Energy Market. The MMU has expanded and refined the analysis of markup measures. Overall, data on the price-cost markup are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2005, with markup index results averaging 0.3 percent for the calendar year.

- **Offer Capping.** PJM rules provide that PJM will offer cap units when their owners would otherwise have the ability to exercise local market power. Offer-capping levels remained steady in 2005. Offer capping is an effective means of addressing local market power.

- **Frequently Mitigated Units.** Rulings in 2005 by the FERC resulted in additional compensation as a form of scarcity pricing for units that were offer-capped more than 80 percent of their real-time run hours over the prior year.

Market Performance: Load and Locational Marginal Prices (LMPs)

- **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 average prices increased from 2004 to 2005. The simple, hourly average system LMP was 37.0 percent higher in 2005 than in 2004, $58.08 per MWh versus $42.40 per MWh. When hourly load levels are reflected, the load-weighted LMP of $63.46 per MWh in 2005 was 43.1 percent higher than 2004's $44.34. When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP was 1.5 percent higher in 2005 than in 2004, $45.02 per MWh compared to $44.34 per MWh. This means that, if it had not been for fuel cost increases, LMP would have been 1.5 percent higher in 2005 than in 2004.

PJM average Real-Time Energy Market prices increased in 2005 over 2004 for several reasons, including, but not limited to, significant increases in fuel cost for the marginal units and in load. PJM load growth in 2005 reflected the geographic expansion created by the DLCO and Dominion integrations and hotter summer weather. The PJM system price was above $150 per MWh for only five hours in 2004; in 2005 it was above the $150 benchmark for 234 hours and above $200 per MWh for 35 hours.

Conclusion

The PJM MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for calendar year 2005, including aggregate supply and demand, concentration ratios, local market concentration ratios, residual supply indices, participation in demand-side response programs, price-cost markup and offer capping in this section of the report. The next section continues the analysis of the PJM Energy Market including measures of market performance.

Aggregate supply increased by about 60,600 MW when comparing the summer of 2005 to the summer of 2004 while aggregate peak load increased by 55,876 MW, retaining the general supply-demand balance from 2004 with a corresponding moderating impact on aggregate Energy Market prices. Market concentration levels remained moderate, relatively few hours exhibited pivotal suppliers and markups remained low. 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.

Energy Market results, including prices, for 2005 reflect supply-demand fundamentals. Significantly higher nominal and load-weighted prices are consistent with a competitive outcome as the higher prices reflect both higher input fuel costs and warmer summer weather. If fuel costs had been the same in 2005 as they had been in 2004, prices would have increased by 1.5 percent rather than the actual 37.0 percent increase in nominal average prices and the 43.1 percent increase in load-weighted average prices. While the existing structure of the Energy Market does not guarantee competitive outcomes, actual market performance results were reasonably competitive in 2005. Given the structure of the Energy Market, tighter markets or a change in participant behavior are potential sources of concern in the Energy Market.

Energy Market, Part 2

The PJM 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.

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 PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. 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 2005 net revenue indicates that the fixed costs of new peaking and midmerit units were not fully covered, but that the fixed costs of new coal-fired baseload were covered. During the seven-year period 1999 to 2005, 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 prices and lower Capacity Market prices.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1 through December 31, 2005, PJM installed capacity grew by approximately 20,100 MW, primarily as a result of the integration of new areas into the PJM markets.

- **PJM Installed Capacity by Fuel Type.** At the end of 2005, PJM installed capacity was about 163,471 MW. Of the total installed capacity, 41.5 percent was coal, 27.5 percent was natural gas, 19.1 percent was nuclear, 7.2 percent was oil, 4.3 percent was hydroelectric and 0.3 percent was solid waste.

- **Generation Fuel Mix.** During 2005, coal was 56.4 percent, nuclear 34.2 percent, natural gas 5.9 percent, oil 1.2 percent, hydroelectric 1.7 percent, solid waste 0.6 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 is potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure.

Scarcity

- **Historical Scarcity Pricing.** Scarcity exists when supply is less than, or equal to, demand where demand includes a level of operating reserves. In PJM, scarcity pricing has resulted under these conditions as the result of the shape of the PJM aggregate supply curve. Scarcity pricing occurred, for example, in the summer of 1999 in PJM.

- **Scarcity in 2005.** In the summer of 2005, the first hot summer since the integrations of Phases 1 through 5, the dynamic in the PJM Energy Market changed. The change was due, in part, to the larger footprint. What had been PJM's entire Energy Market in 1999 was now just a regional part of the market. Units that might have been dispatched in 1999 to meet aggregate PJM load were dispatched in 2005 to resolve constraints associated with bringing lower cost power from the west to east. The result was that rather than units in the eastern part of PJM being dispatched in merit order to meet aggregate demand in the relatively small eastern part of PJM, the units were dispatched out of merit order to solve local constraints. The result, in turn, was that there was not a market mechanism to ensure that prices increased to reflect the scarcity conditions that existed on two occasions.

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, 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. 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 2005.** Operating reserve charges were significantly higher in 2005 than in prior years. The reasons for the observed increase in the operating reserve rate include increased fuel costs, unexpected transmission outages, unanticipated fluctuations in interchange transactions levels and market power.

Conclusion

Wholesale electric power markets, apparently without exception, are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability, typically measured as an acceptable loss of load probability level. This level of reliability is enforced through a requirement to maintain a target level of installed or unforced capacity, which, based on planning models, is considered to be a level that will produce the desired loss of load probability. 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 impact of having capacity in excess of the equilibrium level likely to result from the operation of an energy market alone 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 electricity market design.

While net revenue in PJM has been 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, net revenue has 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.

A capacity market is a formal market-based mechanism 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 also an explicit mechanism for valuing capacity and is preferable to non market and non-transparent mechanisms for that reason.

PJM's proposed 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 Markets.

A market design cannot be deemed truly successful until it results in the retirement and replacement of a significant portion of the existing investment in generating assets, based on incentives endogenous to the market design. The net revenue performance of the markets over six years illustrates that additional market modifications are necessary if PJM is to pass the ultimate test of a market, the successful provision of long-term incentives to invest.

Interchange Transactions

The integration of two additional service territories into the PJM regional transmission organization (RTO) in 2005 significantly expanded PJM's geographic footprint and brought modest changes to its external interfaces. These interfaces are the seams between PJM and other regions. 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.

Overview

Interchange Transaction Activity

Aggregate Imports and Exports

- **Phase 4.** During the four months ended April 30, 2005, PJM, including the DLCO Control Zone, was a net exporter of power, with monthly net interchange averaging -1.2 million MWh.[11] Gross monthly import volumes averaged 3.7 million MWh while gross monthly exports averaged 4.9 million MWh.

- **Phase 5.** During the remaining eight months ended December 31, 2005, PJM, including the Dominion Control Zone, continued to be a net exporter of power. Monthly average net interchange was -1.5 million MWh. Gross monthly import volumes averaged 2.7 million MWh while gross monthly exports averaged 4.2 million MWh.

Interface Imports and Exports[12]

- **Phase 4.** During Phase 4, the two largest net exporting interfaces totaled 36 percent of the total net exporting volume: Michigan Electric Coordinated System (PJM/MECS) at 19 percent and PJM/New York Independent System Operator interface (PJM/NYIS) with 17 percent. Ninety-three percent of the net import volume was carried on three interfaces: PJM/Ohio Valley Electric Corporation (PJM/OVEC) carried 39 percent, PJM/Illinois Power (PJM/IP) carried 38 percent and PJM/Duke Energy Corp. (PJM/DUK) carried 16 percent of the volume.

- **Phase 5.** During Phase 5, the two largest net exporting interfaces totaled 51 percent of the total net exporting volume: Tennessee Valley Authority (PJM/TVA) with 29 percent and MidAmerican Electric Company (PJM/MEC) at 22 percent. Ninety-two percent of the net import volume was carried on three interfaces: PJM/OVEC carried 57 percent, PJM/IP carried 22 percent and FirstEnergy Corp. (PJM/FE) carried 13 percent of the volume.

Modified Interfaces and Pricing Points

- **Removal of Interfaces.** Integration of the DLCO Control Zone into PJM on January 1, 2005, resulted in the removal of the PJM/DLCO interface. The subsequent integration of the Dominion Control Zone on May 1, 2005, resulted in the removal of the PJM/VAP interface.

11 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.

12 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.

- **Pricing Point Changes.** On January 1, 2005, the DLCO pricing point was eliminated as a result of the DLCO integration. On April 1, 2005, the MISO pricing point was created as a result of the Midwest ISO's introduction of markets. On May 1, 2005, the Southeast pricing point was modified to account for the integration of the Dominion Control Zone.

Interchange Transaction Topics

Existing and Proposed Operating Agreements with Bordering Areas

- **Midwest ISO.** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (JOA)[13] entered its second phase of implementation including market-to-market activity and coordinated market-based congestion management within and between both markets.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[14] The Joint Reliability Coordination Agreement (JRCA), executed on April 22, 2005, provides for the active management of seams among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The Agreement provides for comprehensive reliability management and congestion relief among the three regions.

- **PJM and Progress Energy Carolinas, Inc. (PEC) Joint Operating Agreement (JOA).**[15] An operating agreement between PJM and PEC, approved by the FERC on September 9, 2005, with an effective date of July 30, 2005, provides for market-to-non market coordination.

PJM TLRs

- The number of transmission loading relief procedures (TLRs) issued by PJM declined after the integration of the AEP and DAY Control Zones. The integration meant that PJM could redispatch generating units to relieve constraints on facilities in the newly integrated areas where PJM had previously relied on TLRs for constraint control. The result was a drop in the number of TLRs called by PJM, particularly in the AEP Control Zone.

Actual Versus Scheduled Power 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. Loop flows have negative consequences because they constitute unscheduled use of PJM's transmission system, affect real-time system operations and affect the revenue adequacy of FTRs because loop flows do not pay congestion costs. Although PJM's total scheduled and actual flows differed by about 4 percent in 2005, there were significant differences for individual interfaces. PJM's method of defining pricing points

13 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 31, 2003) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (2.73 MB).

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

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

is designed to provide price signals consistent with the actual power flows and thus to minimize the incentive to create loop flow.

Interchange Issues

- **PJM and Midwest ISO Transaction Issues.** During 2005, the relationship between prices at the PJM/MISO interface and at the MISO/PJM interface appeared to reflect economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.

- **PJM and New York ISO Transaction Issues.** During 2005, the relationship between prices at the PJM/NYIS interface and at the New York Independent System Operator (NYISO) PJM proxy bus appeared to reflect economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the NYISO. As in 2004, however, both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

- **Consolidated Edison and PSEG Wheeling Contracts.** Two contracts governing wheeling of up to 1,000 MW of power through PJM into New York City were the subject of a November 2001 complaint to the FERC. The FERC issued an order on May 18, 2005, defining a protocol to resolve this issue which was implemented in July 2005. Based on early performance of the protocol, Consolidated Edison has formally asked the FERC to require PJM and NYISO to improve operations under the protocol to increase delivery performance, and PJM and NYISO are working to resolve these issues.

- **Ramp and Transmission Reservations.** PJM should consider development of rules that limit a market participant's ability to reserve more ramp than is actually either needed or used in order to facilitate the efficient use of limited ramp capability.

Conclusion

The PJM MMU analyzed the transactions between PJM and neighboring control areas for 2005 including evolving transactions patterns, economics and issues. The location of PJM transactions with external areas has changed significantly as a result of the substantial expansion of the PJM footprint over the last two years. New interfaces dominate export and import activity. In contrast to the first five years of PJM operations, PJM continued the recent pattern of being a net exporter of energy. While exports and imports have historically primarily cleared in the Real-Time Energy Market, transactions in the Day-Ahead Energy Market continued to grow in volume. PJM has entered into a number of agreements with neighboring control areas that govern reliability and economic coordination. As interactions with external areas are increasingly governed by economic redispatch, interface prices and volumes reflect supply and demand conditions and the number of TLRs has declined. PJM continues to face significant loop flows with substantial impacts on PJM for reasons that are not yet well understood. A cooperative analysis with the Midwest ISO would contribute to the understanding that is required before a solution can be designed. The Consolidated Edison/PSEG wheeling contracts are now managed under a FERC-approved protocol that has improved operations and additional improvements are being made. The allocation and management of ramp, the capability to import into or export from PJM, continue to create potential issues and improvements are also required in this area.

Capacity Markets

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 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.[16]

The PJM Capacity Credit Market[17] 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,[18] Monthly and Multimonthly Capacity Credit Markets. The PJM Capacity Credit Market is intended to provide a transparent, market-based mechanism for competitive 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 Capacity Credit Market permits LSEs to match capacity resources with short-term shifts in retail load while Interval, Monthly and Multimonthly Capacity Credit Markets provide mechanisms to match longer term obligations with capacity resources.

From June 2004 through May 2005 a separate ComEd Capacity Credit Market operated, under the terms of PJM rules, to balance supply of and demand for capacity unmet by the bilateral market or self-supply in the ComEd Control Area.[19] The ComEd Capacity Credit Market consisted of Interval, Monthly and Multimonthly Capacity Credit Markets.

Overview

When the 2004 calendar year ended, PJM was operating two Capacity Markets, the PJM Capacity Market and the ComEd Capacity Market. The PJM Capacity Market (or simply PJM) was comprised of the 11 control zones of the Mid-Atlantic Region and the AP, AEP and DAY Control Zones. DLCO, which joined PJM on January 1, 2005, and Dominion, which joined PJM on May 1, 2005, were added to the PJM Capacity Market on the dates they joined. The ComEd Capacity Market was comprised solely of the ComEd Control Zone.

The ComEd Capacity Credit Market was added to the PJM Capacity Credit Market on June 1, 2005, to create a single PJM Capacity Market.[20]

16 See Appendix H, "Glossary," for definitions of PJM Capacity Credit Market terms.

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

18 PJM defines three intervals for its Capacity Markets. 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.

19 All ComEd Capacity Market values (capacities) are in terms of installed MW.

20 For purposes of Section 5, "Capacity Markets" and Appendix E, "Capacity Markets," these markets are identified as the PJM Capacity Market (or PJM) and the ComEd Control Zone Capacity Market (or ComEd). These markets are referred to collectively as the Capacity Markets for the regional transmission organization (RTO).

PJM Capacity Market

Market Structure for the PJM Capacity Market

Ownership Concentration

- **Phase 4.** Structural analysis of the PJM Capacity Credit Market found that, on average, its daily markets exhibited low concentration levels while its monthly and multimonthly markets exhibited moderate concentration levels during the period January through April 2005.

- **Phase 5.** Structural analysis of the PJM Capacity Credit Market found that, on average, its daily markets exhibited moderate concentration levels while its monthly and multimonthly markets exhibited high concentration levels during the period May through December 2005.

- **Total Capacity.** The Capacity Credit Markets include approximately 5 percent of total capacity obligations. The MMU also analyzed the ownership of total PJM capacity in order to develop a more complete assessment of market structure for capacity. The ownership of total capacity exhibited low concentration levels throughout the year, decreasing from an HHI of 953 on January 1 to 917 on December 31. The highest market share declined from 21.6 percent to 16.6 percent. There was a single pivotal supplier throughout the year, meaning that the capacity of the largest supplier was always required in order to meet the capacity obligation.

Supply and Demand

- **Phase 4.** From January through April 2005, unforced capacity and obligations remained relatively constant in the PJM Capacity Market as compared to Phase 3. Average unforced capacity rose by 2,123 MW or 2.0 percent to 110,545 MW. Average load obligations climbed by 1,295 MW or 1.3 percent to 100,201 MW or 10,344 MW less than average unforced capacity. Overall Capacity Credit Market transactions increased by 18.7 percent from Phase 3. Daily Capacity Credit Market volumes increased by 44.7 percent, while Monthly and Multimonthly Capacity Credit Market volumes increased by 16.4 percent and 10.7 percent, respectively.

- **Phase 5.** From May through December 2005, unforced capacity and obligations increased with Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Average unforced capacity rose 35.6 percent to 149,888 MW. Average load obligation climbed 39.5 percent to 139,736 MW. Overall Capacity Credit Market transactions increased by 22.0 percent from Phase 4. Daily Capacity Credit Market volumes increased by 9.3 percent, while Monthly and Multimonthly Capacity Credit Market volumes increased by 35.7 percent and 23.8 percent, respectively.

External and Internal Capacity Transactions

- **Phase 4.** From January through April 2005, imports averaged 5,855 MW, which was a decrease of 537 MW or 8.4 percent from the Phase 3 average of 6,392 MW. Exports averaged 3,953 MW, which was an increase of 742 MW or 23.1 percent from the Phase 3 average of 3,211 MW. Average net exchange decreased 1,279 MW or 40.2 percent to 1,902 MW from the Phase 3 average of 3,181 MW. Internal bilateral transactions averaged 91,880 MW, which was an increase of 14,712 MW or 19.1 percent from the 77,168 MW average for Phase 3.

- **Phase 5.** From May through December 2005, imports averaged 4,208 MW, which was a decrease of 1,647 MW or 28.1 percent from the Phase 4 average. Exports averaged 4,856 MW, which was an increase of 903 MW or 22.8 percent from the Phase 4 average. Average net exchange decreased 2,550 MW or 134.1 percent to -648 MW from the Phase 4 average of 1,902 MW. These changes were the result of the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Internal bilateral transactions averaged 150,597 MW, which was an increase of 58,717 MW or 63.9 percent from the average for Phase 4. This increase was the result of Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market.

Active Load Management (ALM Credits)

- **Phase 4.** From January through April 2005, ALM credits in the PJM Capacity Market averaged 1,654 MW, down less than 1 percent from 1,662 MW in Phase 3.

- **Phase 5.** From May through December 2005, ALM credits in the PJM Capacity Market averaged 1,993 MW, an increase of 339 MW or 20.5 percent from Phase 4. This increase was attributable to the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1, 2005, as the mandatory interruptible load (MIL) credits in ComEd were converted to ALM credits in PJM.

Market Performance in the PJM Capacity Market

Capacity Credit Market Volumes and Prices

- **Phase 4.** From January through April 2005, total PJM Capacity Credit Market transactions averaged 5,649 MW (5.6 percent of obligation), which was 888 MW higher than the Phase 3 average (4.8 percent of obligation). Total PJM Capacity Credit Market prices averaged $7.72 per MW-day, which was $2.81 per MW-day less than the Phase 3 average.

- **Phase 5.** From May through December 2005, total PJM Capacity Credit Market transactions averaged 6,892 MW (4.9 percent of obligation), which was 1,243 MW higher than the Phase 4 average. Total PJM Capacity Credit Market prices averaged $5.47 per MW-day, which was $2.25 per MW-day less than the Phase 4 average.

- **Calendar Years 1999 through 2005.** Daily Capacity Market volume declined from 2.5 percent of average obligation in 2000 to 1.2 percent in 2005.[21] Monthly and Multimonthly Capacity Market volume increased from 3.0 percent of obligation in 2000 to 3.9 percent of average obligation in 2005. Capacity Market prices increased from 1999 through 2001 and have declined and remained relatively stable since 2001 with the exception of the summer of 2004.

21 The year 2000 is used as the base year because it was the first full calendar year for which unforced capacity was used rather than installed capacity.

ComEd Capacity Market

Market Structure for the ComEd Capacity Market

Ownership Concentration

- **June 2004 through May 2005.** Structural analysis of the ComEd Capacity Credit Market found that its Monthly and Multimonthly Markets exhibited high levels of concentration.

- **Total Capacity.** The ComEd Capacity Credit Markets include about 6 percent of total ComEd capacity obligations. The MMU also analyzed total ComEd capacity in order to develop a more complete assessment of market structure for capacity. The ownership of total capacity exhibited high concentration levels throughout the year, with HHI declining from 4525 on June 1, 2004, to 4070 on May 31, 2005, and with the maximum market share declining from 64.2 percent to 59.8 percent and RSI below 1.0 throughout the year, indicating the presence of a single pivotal supplier. The presence of a single pivotal supplier means that the capacity of the largest supplier was always required in order to meet the capacity obligation.

Supply and Demand

- **June 2004 through May 2005.** ComEd electricity distribution companies (EDCs) together had an 81.6 percent market share of load obligation. During this period, capacity resources exceeded capacity obligations in the ComEd Capacity Market every month, resulting in an average net excess of 6,261 MW, or 31.7 percent of average obligation for the period.

External and Internal Capacity Transactions

- **June 2004 through May 2005.** The ComEd Control Zone was a net exporter of capacity resources, with exports increasing from 747 MW on June 1 to 2,289 MW on May 31. Almost half of the increase was the result of increased exports to the PJM Capacity Market. Imports remained relatively constant. Internal bilateral transactions decreased by 6,361 MW on October 1 due to the lower interval peak for the October to December period.

Market Performance in the ComEd Capacity Market

Capacity Credit Market Volumes and Prices

- **June 2004 through May 2005.** Total ComEd Capacity Credit Market transactions averaged 1,229 MW, which was 6.2 percent of load obligation. Prices averaged $23.99 per MW-day.

Generator Performance

From 1996 to 2001, the average, PJM equivalent demand forced outage rate (EFORd) declined, reaching 4.6 percent in 2001, but then increased to 5.2 percent in 2002, 7.0 percent in 2003 and 8.0 percent in 2004.[22] In 2005, the average PJM EFORd decreased to 7.3 percent. The decrease in EFORd from 2004 to

22 As a general matter, the current year EFORd data reported in prior state of the market reports may be revised based on final data submitted after the publication of the report as final EFORd data are not available until after the publication of the reports.

2005 was the result of decreased forced outage rates across all unit types with the exception of combustion turbines. These forced outage rates are for the PJM Mid-Atlantic Region and the AP Control Zone only. The forced outage rate in 2005 was 6.5 percent for all zones within the PJM Control Area.[23]

Conclusion

The PJM MMU analyzed key measures of PJM Capacity Market and of ComEd Capacity Market structure and performance for calendar year 2005 and for the period from June 2004 through May 2005 for ComEd, including concentration ratios, prices, outage rates and reliability. Given the basic features of market structure in both the PJM and ComEd Capacity Markets, including high levels of concentration, the relatively small number of 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 is high. Market power is endemic to the existing structure of PJM Capacity Markets.

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 even in a highly concentrated market. 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.

The MMU found serious market structure issues, but no exercise of market power during these time periods. 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 2005. The PJM Capacity Market results were competitive during 2005. The ComEd Capacity Market results were reasonably competitive for the 12-month period from June 2004 through May 2005. Market power remains a serious concern for the MMU in the PJM Capacity Market based on market structure conditions in this market.

Ancillary Service Markets

The 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 – spinning reserve services; and 6) operating reserve – supplemental reserve services.[24] Of these, PJM currently provides regulation, energy imbalance and spinning reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis.

23 In some cases, data for the AEP, DAY, DLCO, Dominion and ComEd Control Zones may be incomplete for the years 2004 and 2005. Only data that have been reported to PJM were used.

24 75 FERC ¶ 61,080 (1996).

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.[25] Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes). Longer term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Spinning reserve is a form of primary reserve. To provide spinning a generator must be synchronized to the system and capable of providing output within 10 minutes.

Both the Regulation and Spinning Reserve Markets are cleared on a real-time basis. A unit can be selected for either spinning reserve or regulation or neither, but it cannot be selected for both. The Regulation and Spinning Reserve Markets are cleared simultaneously and cooptimized with the Energy Market and operating reserve requirements to minimize the cost of the combined products.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling.[26] 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.

In both Phase 4 and Phase 5, PJM operated two Regulation Markets: one for the Mid-Atlantic Region and a second for the Western Region. On August 1 of Phase 5, PJM combined both into a single PJM Combined Regulation Market for a six-month trial period. After the trial period, based on analysis of market results and a report by the PJM MMU, PJM stakeholders will vote on whether to keep the combined market.

During Phase 4, PJM operated three Spinning Reserve Markets: one for the Mid-Atlantic Region, one for the Western Region and one for the ComEd Control Zone. During Phase 5, PJM operated a fourth Spinning Reserve Market for Dominion.

The analysis treats each of the two Regulation Markets and each of the three Spinning Reserve Markets separately during Phase 4. The market analysis treats each of the two Regulation Markets separately during the May 1 through July 31 component of Phase 5 (Phase 5-a), and as a single Regulation Market during the August 1 through December 31 component of Phase 5 (Phase 5-b). Each of the four Spinning Reserve Markets is treated separately for the entire Phase 5 period.

Overview – Regulation and Spinning Reserve Markets

The MMU has reviewed structure, conduct and performance indicators for the identified Regulation Markets. The MMU concludes that the Regulation Markets functioned effectively, except for some minor problems of insufficient regulation supply shortly after the start of Phase 5 and during times of minimum generation. The Regulation Markets produced competitive results throughout calendar year 2005 based on the regulation market-clearing price. The Regulation Market prices reflected the fact that offers in the Western Region were capped during Phase 4 and that the offers of two large participants, AEP and Dominion, were capped at cost plus a margin throughout Phase 5, in both cases because the Western Region Regulation Market was determined to be not structurally competitive.

25 Regulation is used to help control the area control error (ACE). See Appendix F, “Ancillary Service Markets,” for a full definition and discussion of ACE.
26 See “PJM Manual for Scheduling Operations, M-11,” Revision 25 (August 19, 2005), p. 71.

The MMU has reviewed structure, conduct and performance indicators for the identified Spinning Reserve Markets. The MMU concludes that the Spinning Reserve Markets functioned effectively. The Spinning Reserve Markets produced competitive results throughout calendar year 2005 based on the spinning market-clearing price. The Spinning Reserve Market prices reflected the fact that all offers were capped at cost plus a margin because the markets have been determined to be not structurally competitive.

The Regulation Markets

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 structure of the Combined Regulation Market was also evaluated based on the five months of available data and the MMU concluded that this market is characterized by lower levels of concentration, smaller market shares, a smaller number of hours with pivotal suppliers and inelastic demand. The conduct of market participants within these market structures has been consistent with competition consistent with existing offer capping, and the market performance results have been competitive.

- **Mid-Atlantic Region.** The Regulation Market in the PJM Mid-Atlantic Region was cleared based on participants' price offers during Phases 4 and 5-a. All suppliers were paid the market-clearing price, which is a function of the supply curve and PJM-defined demand. The supply curve consists of offered and eligible MW and the associated offer prices which are a combination of unit-specific offers plus opportunity cost (OC) as calculated by PJM.[27]

- **Western Region.** The Regulation Market in the Western Region during Phase 4 was cleared based on participants' cost-based offers. The cost-based regulation offers are defined to be the unit-specific incremental cost of providing regulation plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM. During Phase 5-a, the market was cleared using a combination of price-based offers and cost-based offers. In Phase 5, Dominion and AEP were required to make cost-based offers based on their dominant position in the market while other participants made price offers.

- **PJM Combined Regulation Market.** During the trial period for the PJM Combined Regulation Market, the market was cleared using a combination of price-based offers and cost-based offers. Dominion and AEP were required to make cost-based offers based on their dominant position in the market while other participants made price offers.

Market Structure

- **Demand.** Demand for regulation is determined by PJM based on an evaluation of the regulation required in order to meet reliability objectives. Required regulation remained constant for each control region throughout 2005 except for two periods during which a temporary adder was implemented at the direction of PJM.

- **Supply.** The supply of offered and eligible regulation in the PJM Mid-Atlantic Region was generally both stable and adequate, with an average 1.92 ratio of regulation supply offered and eligible to the hourly regulation requirement during Phases 4 and 5-a. While the average ratio of hourly regulation supply

27 As used here, the term, "opportunity cost" (OC), refers to the estimated lost opportunity cost (LOC) that PJM uses to create a supply curve on an hour-ahead basis. The term, "lost opportunity cost," refers to opportunity costs included in payments to generation owners.

offered and eligible to regulation required was 1.64 for the Western Region during Phases 4 and 5-a, at times an inadequate supply of regulation was offered and eligible to participate in the market on an hourly basis in the Western Region. The average ratio of hourly regulation supply offered and eligible to regulation required was 1.88 for the PJM Combined Regulation Market during Phase 5-b.

Concentration of Ownership

- **Mid-Atlantic Region.** During Phase 4 and Phase 5-a, the PJM Mid-Atlantic Region Regulation Market for eligible regulation had an average Herfindahl-Hirschman Index (HHI)[28] of 1751 which is classified as "moderately concentrated."[29] Less than 1 percent of the hours had an eligible regulation HHI above 2500. There were two suppliers with market shares greater than, or equal to, 20 percent. Seven percent of the hours had a single pivotal supplier, 48 percent of the hours had two pivotal suppliers and 88 percent of the hours had three pivotal suppliers.

- **Western Region.** During Phase 4 and Phase 5-a, the Western Region Regulation Market for eligible regulation had an average HHI of 2802 which is classified as "highly concentrated" and 58 percent of the hours had an HHI above 2500. There was a single pivotal supplier in 62 percent of the hours. One hundred percent of the hours had two pivotal suppliers.

- **PJM Combined Regulation Market.** During Phase 5-b, the PJM Combined Regulation Market had an average HHI of 1079 which is classified as "moderately concentrated." No suppliers had market shares greater than, or equal to, 20 percent. During 1 percent of hours, there was a single pivotal supplier. During 6 percent of hours, there were two pivotal suppliers. During 29 percent of the hours, there were three pivotal suppliers. For all units except CTs, during 5 percent of hours, there was a single pivotal supplier, during 23 percent of hours, there were two pivotal suppliers and during 68 percent of the hours, there were three pivotal suppliers.

Market Conduct

- **Offers.** The offer price is the only component of the total regulation offer price provided by the unit owner and is applicable for the entire operating day. The regulation offer price is subject to a $100 per MWh offer cap in the Mid-Atlantic Region, was subject to offer capping in Phase 4 in the Western Region and was subject only to a $100 per MWh offer cap in Phase 5 in the Western Region, with the exception of the dominant suppliers, Dominion and AEP, whose offers were capped at marginal cost plus $7.50 per MWh plus opportunity cost. The average MW-weighted offer price for regulation in the PJM Mid-Atlantic Region during Phases 4 and 5-a was $15.63. The average MW-weighted offer price for regulation in the Western Region Regulation Market during Phases 4 and 5-a was $7.73. For the PJM Combined Regulation Market during Phase 5-b, the average MW-weighted offer price for regulation was $16.29.

Market Performance

- **Price.** For the entire PJM RTO from January 1, 2005, to December 31, 2005, the average price per MWh (regulation market-clearing price) associated with meeting PJM's demand for regulation was

28 See Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
29 The market structure metrics reported in this summary are based on regulation capacity that is both offered to the market and is eligible to provide regulation.

$49.73. For the PJM region during Phases 4 and 5-a, the average price per MWh for regulation was $36.39. For the Western Region Regulation Market during Phases 4 and 5-a, the average price per MWh for regulation was $42.64. For the PJM Combined Regulation Market during Phase 5-b, the average price per MWh was $64.03.

The Spinning Reserve Markets

The structure of each of the Spinning Reserve Markets 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 and opportunity cost. The conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Prices for spinning in the PJM Mid-Atlantic Region, the ComEd Control Zone, the Western Region and Dominion are market-clearing prices determined by the supply curve and PJM-defined demand. The cost-based spinning offers are defined to be the unit-specific incremental cost of providing spinning reserve plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM.

Market Structure

- **Demand.** Computed in accordance with the specific spinning reserve requirements, the average MW spinning requirement was: 1,091 MW for the PJM Mid-Atlantic Region; 217 MW for the ComEd Spinning Zone; 437 MW for the Western Region; and 5 MW for the Southern Spinning Reserve Zone (May to December only).

- **Supply.** For the PJM Mid-Atlantic Region, the offered and eligible excess supply ratio was 1.15. For the Western and Southern Regions, the ratio was 1.76. For the ComEd Control Zone, the ratio was 1.21.

- **Concentration of Ownership.** In 2005, market concentration was high in the Tier 2 Spinning Reserve Market. The average offered and eligible Spinning Reserve Market HHI for the PJM Mid-Atlantic Region throughout 2005 was 2940. The average Spinning Reserve Market HHI for the Western Region was 4593. The average Spinning Reserve Market HHI for ComEd Control Zone was 8844. The average Spinning Reserve Market HHI for Dominion was 10000.

Market Performance

- **Price.** Load-weighted, average price associated with meeting the PJM system demand for Tier 2 spinning reserve throughout 2005 was $14.41 per MW, a $0.45 per MW decrease from 2004. The load-weighted, average price in the PJM Mid-Atlantic Region for Phases 4 and 5 was $15.44 per MW. The load-weighted, average price for spinning reserve in the ComEd Control Zone during Phases 4 and 5 was $12.73. The load-weighted, average price for spinning in the Western Control Zone during Phases 4 and 5 was $13.23. The load-weighted, average price for spinning in Dominion during Phase 5 was $13.08.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition. The MMU will make a recommendation in the near future as to whether the consolidation has resulted in a market that is structurally competitive. The market continues to be based on price offers for most sellers and all sellers are paid a market-clearing price based on offers plus opportunity costs. The result of this design has been a competitive outcome and consistent with competitive offers from all participants whether offer-capped or not. The marginal costs of providing regulation have been clearly defined and are consistent with the offers that would be made if the suppliers were behaving competitively.

PJM's Spinning 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 this approach to ancillary service markets. Even in the presence of structurally non-competitive markets, there are transparent, market-clearing prices based on competitive offers that account explicitly and accurately for opportunity costs. 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.

Congestion

Congestion occurs when available, lower-cost energy cannot be delivered to all loads for a period because transmission capabilities are not adequate to meet some loads for the period. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in this constrained area must be dispatched to meet that load.[30] 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. 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 of pricing energy supply 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 a negative nor a positive but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized through the capability of the transmission system to deliver the cheapest energy to all parts of the system in every hour. A rational planning process would attempt to choose the least cost combination of transmission and generation and would reflect the fact that investments in both transmission and generation have costs. The transmission system provides one 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 ARRs and/or FTRs. While the transmission system and, therefore, FTRs are not a complete hedge against congestion, FTRs do provide a substantial offset to the cost of congestion to firm load.

30 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.

As PJM integrated new transmission zones during 2005, the patterns of congestion changed, reflecting additional transmission and generation resources with new cost structures, load requirements and transmission system characteristics.

Overview

Congestion Cost

- **Total Congestion.** Congestion costs have ranged from 6 percent to 10 percent of PJM annual total billings since 2000. Congestion costs were approximately 9 percent of total PJM billings for 2005, as they were in 2004. Total congestion costs were $2.09 billion in calendar year 2005, a 179 percent increase from $750 million in calendar year 2004. The increased size of the total PJM Energy Market contributed to the increase in total congestion charges. The total PJM billing for 2005 was $22.63 billion, a 160 percent increase over the approximately $8.70 billion billed in 2004.

- **Monthly Congestion.** Differences in monthly congestion costs continued to be substantial. In 2005, 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.** FTRs were paid at 100 percent of the target allocation level for the 12-month planning period that ended May 31, 2005. FTRs were paid at 91 percent of the target allocation level through December 31, 2005, of the planning period ending May 31, 2006.

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.

- **Congested Facilities.** Congestion frequency increased in calendar year 2005 as compared to 2004. During 2005, there were 17,524 congestion-event hours as compared to 11,205 congestion-event hours in 2004. Interfaces, transformers and lines experienced overall increases in congested hours during 2005 as compared to 2004. The expansion of PJM through the integration of new control zones contributed to the increase in congestion frequency.

- **Zonal Congestion.** In calendar year 2005, the AP Control Zone experienced the largest increase in congestion frequency of any control zone in PJM. The 2,877 congestion-event hours in the AP Control Zone were a 746 percent increase over the 340 congestion-event hours the zone had experienced during 2004. The Doubs transformer and the Mount Storm-Pruntytown line together contributed 1,222 congestion-event hours or 42 percent of the AP Control Zone total. In the AECO Control Zone, there was a 119 percent increase in congestion on the Laurel-Woodstown 69 kV line. With 879 congestion-event hours, the Laurel-Woodstown line comprised 50 percent of all AECO Control Zone congestion during 2005. The AEP Control Zone saw increases in congestion on the Cloverdale-Lexington, Mahans Lane-Tidd and Kanawha-Matt Funk lines during 2005. These three facilities accounted for 1,357 congestion-event hours, or 71 percent of the total AEP Control Zone congestion during 2005. Congestion on 500 kV zone facilities increased in 2005 as compared to 2004, contributing 5,548 congestion-event hours or 32 percent of the total PJM congestion-event hours. Three 500 kV zone facilities, the Wylie Ridge transformer, Kammer transformer and the Bedington-Black Oak line contributed 4,045 congestion-event hours or 73 percent of all 500 kV zone congestion-event hours during 2005. The Wylie Ridge transformer, the Kammer transformer and the Bedington-Black Oak line were the first, second and third most frequently constrained facilities, respectively, during 2005.

Post-Contingency Congestion Management Program

- **Implementation.** PJM implemented a post-contingency congestion management protocol on September 1, 2004, under which a transmission facility may be operated to a 30-minute, short-term emergency rating if there is sufficient quick start generation capability or switching to respond to the loss of a facility.

- **Initial Results.** Beginning on June 1, 2005, there were 36 facilities included in this program, an increase of 21 facilities over the number as of June 1, 2004. During 2005, 136 hours of off-cost operation were avoided through the use of this protocol.

Economic Planning Process

- **Implementation.** PJM's regional transmission expansion planning (RTEP) protocol includes an economic planning component to identify the transmission upgrades needed to address unhedgeable congestion whether through a market window or directly through the RTEP protocol. However, the current methodology for calculating unhedgeable congestion overstates the value of economic generation as a congestion hedge unless economic local generation is owned by load. The result of such an overstatement is to undervalue the cost of unhedgeable congestion and to undervalue transmission upgrades. This, in turn, would lead to the rejection of cost-effective economic transmission upgrades under the cost-benefit calculation.

- **Early Results.** By December 31, 2005, 74 facilities had experienced sufficient levels of unhedgeable congestion to trigger the opening of a market window to solicit merchant solutions to relieve congestion. Of these, 31 or approximately 42 percent had completed their initial studies.

Conclusion

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 increased in 2005 in approximate proportion to the total increase in total billing as PJM continued to expand its footprint. The year 2005 was the first full calendar year reflecting the impact of areas integrated in 2004 in addition to the phased 2005 integrations of the DLCO and Dominion Control Zones. This constituted a dramatic change in the nature of the power system managed by PJM, including large new areas under LMP-based redispatch where borders had previously been managed by TLR procedures and ramp limits. Efficient redispatch displaced the less efficient management of borders. That redispatch was more efficient and, at the same time, revealed the underlying limitations of the ability of the transmission system over the broad footprint 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 for the first time, is an essential input to a rational market and planning process that covers the entire expanded footprint for the first time. PJM has made significant steps in the transmission planning process and needs to make more, in particular ensuring that the calculation of the costs and benefits of congestion is done appropriately. With all the changes, ARRs and FTRs continued to serve as a hedge against congestion. FTRs were paid at 100 percent of their target allocation for the planning year ended May 31, 2005, and at 91 percent for the first seven months of the current planning year.

Financial Transmission and Auction Revenue Rights

FTRs and ARRs give firm transmission customers an offset against congestion costs. In PJM, FTRs have been made available to firm point-to-point and network service transmission customers as a hedge against congestion costs since the inception of LMP on April 1, 1998.[31]

FTRs and ARRs are 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. ARRs provide holders with revenues or charges based on the locational price difference between ARR sources and sinks determined in the Annual FTR Auction.[32] These price differences are based on the bid prices of participants in the Annual FTR Auction Market. 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. 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.

Firm transmission customers have access to FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission customers receive requested FTRs to the extent that they are consistent both with the physical capability of the transmission system and with FTR requests of other eligible customers.

Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[33] Firm transmission customers have the option either to take allocated ARRs or to take the underlying FTRs through a process called self-scheduling.

PJM also runs Monthly FTR Auctions designed to permit bilateral FTR transactions and to allow any market participant to buy residual system FTRs. PJM introduced 24-hour FTRs into the Monthly Auctions for the 2003 to 2004 planning period. At the same time, PJM also added annual and monthly FTR option products to the FTR Auction Market. Unlike standard FTRs, the FTR options can never be a financial liability.

The *2005 State of the Market Report* focuses on two FTR/ARR planning periods: the 2004 to 2005 planning period which covers June 1, 2004, to May 31, 2005, and the 2005 to 2006 planning period which covers June 1, 2005, through May 31, 2006.[34]

31 PJM network and firm, long-term point-to-point transmission service customers are referred to as eligible customers.

32 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.

33 87 FERC ¶ 61,054 (1999).

34 Annual FTR accounting changed from calendar year to planning period beginning with the 2003 to 2004 planning period. The transition to this new accounting period required the 2003 calendar year accounting to be extended by five months to encompass January 1, 2003, through May 31, 2004.

For the 2005 to 2006 planning period (June 1, 2005, through May 31, 2006), ARR allocations were provided to eligible market participants in the Mid-Atlantic Region and AP Control Zone. The choice of ARRs or direct allocation FTRs was available in the recently integrated ComEd, AEP, DAY, DLCO and Dominion Control Zones. Participants in newly integrated control zones retain the option of ARR allocations or direct allocation FTRs for the two planning periods following integration. After that, they can participate fully in the FTR Markets and receive ARR allocations through the PJM allocation process. For example, since its May 1, 2004, integration, direct allocation FTRs were available to participants in the ComEd Control Zone for the 2004 to 2005 planning period and for the 2005 to 2006 planning period. For subsequent periods, eligible customers in the ComEd Control Zone will be full participants in the ARR allocation process.

Overview

Financial Transmission Rights (FTRs)

- **Products.** FTR products include FTR obligations and FTR options. Each of these is available for 24-hour, off-peak and on-peak periods.

- **Supply and Demand.** PJM operates an Annual FTR Auction Market for all zones in the PJM footprint. Participants in newly integrated zones must choose to receive either an FTR allocation or an ARR allocation before the start of Annual FTR Auction. In the Annual Auction Market, total FTR Auction demand was 871,841 MW during the 2005 to 2006 planning period, up from 861,323 MW during the 2004 to 2005 planning period. The Auction Market cleared 141,179 MW (16.2 percent of demand), leaving 730,662 MW of uncleared bids. In the FTR Auction Market for the 2004 to 2005 planning period, the demand was 861,323 MW while the market cleared only 119,629 MW (13.9 percent of demand), leaving uncleared bids of 741,694 MW. Under the Annual FTR Auction, there is no limit on FTR demand. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and numerous combinations of FTRs are feasible. The principal binding constraints limiting the supply of FTRs were the Jefferson 138 kV line, the Mahans Lane 138 kV line and the Branchburg 500/230 kV transformer.

  In the allocation of FTRs or ARRs for the ComEd, AEP, DAY, DLCO and Dominion Control Zones, total demand for annual FTR allocations was 42,641 MW for the 2005 to 2006 planning period, down from 65,757 MW for the 2004 to 2005 planning period. This decrease was the net result of a number of factors including the AP Control Zone becoming ineligible for direct allocation FTRs, increased demand by customers in the ComEd Control Zone for ARRs rather than directly allocated FTRs and the integration of Dominion. Demand for allocations cleared at 39,429 MW, leaving uncleared bids of 3,212 MW. The principal binding constraints limiting the supply of allocated FTRs were the Chesterfield-Lakeside 230 kV line, the Kanawha River-Matt Funk 345 kV line, the South Canton transformer and the Crete-St Johns 345 kV line, and the Bedington-Black Oak interface.

  In addition to the Annual FTR Auction and allocation markets, PJM conducts Monthly FTR Auction Markets covering the entire PJM footprint, to allow participants to buy and sell any residual transmission entitlement that is available after FTRs are awarded from the Annual FTR Auction. Any market participant can participate in the Monthly Auctions as a buyer or as a seller.

- **Ownership Concentration.** Ownership of FTRs is moderately concentrated and maximum market shares exceed 20 percent in some cases based on the results of the Annual Auction. Given PJM's Annual and Monthly FTR Auctions, the market shares may fluctuate when FTR-owning entities trade, buy or sell the instruments.

- **Volume.** Of 914,483 MW in annual FTR requests for the 2005 to 2006 planning period, 180,609 MW (19.7 percent) were cleared. Of 927,081 MW[35] in annual FTR requests for the 2004 to 2005 planning period, 179,950 MW (19.4 percent) were cleared.

- **Price.** For the 2005 to 2006 planning period, 84.3 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 89.1 percent for less than $2 per MWh. The overall average prices paid for annual FTR obligations were $1.56 per MWh for 24-hour, $0.40 per MWh for on-peak and $0.33 per MWh for off-peak FTRs. Comparable prices for the 2004 to 2005 planning period were $1.27 per MWh for 24-hour, $0.16 per MWh for on-peak and $0.13 per MWh for off-peak FTRs. The overall average prices paid for 2005 to 2006 planning period annual FTR obligations and options were $0.10 per MWh and $0.18 per MWh, respectively, compared to $0.31 per MWh and $0.19 per MWh, respectively, in the 2004 to 2005 planning period.

- **Revenue.** Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,672 million of FTR revenues during the first seven months of the 2005 to 2006 planning period and $1,118 million during the 12-month 2004 to 2005 planning period.[36]

- **Revenue Adequacy.** FTRs were paid at 91 percent of the target allocation level for the 2005 to 2006 planning period, through the end of calendar year 2005.[37] FTRs were 100 percent revenue adequate during the 2004 to 2005 planning period.

Auction Revenue Rights (ARRs)

- **Supply and Demand.** Total demand in the annual ARR allocation was 82,343 MW for the 2005 to 2006 planning period, up from 55,128 MW during the 2004 to 2005 planning period and 39,888 MW during the 2003 to 2004 planning period. ARR demand is limited by the total amount of network and long-term, firm point-to-point transmission service. ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs, and numerous combinations of ARRs are feasible.

- **Volume.** Of 82,343 MW in ARR requests for the 2005 to 2006 planning period, 59,410 MW were allocated. Eligible market participants subsequently self-scheduled 32,631 MW (55 percent) of these allocated ARRs as annual FTRs. Of 55,128 MW in ARR requests for the 2004 to 2005 planning period, 33,589 MW were allocated. Eligible market participants subsequently self-scheduled 13,061 MW (39 percent) of these allocated ARRs as annual FTRs.

35 The number reported here is slightly higher than the number reported in *2004 State of the Market Report*, which was 924,154 MW, because the number reported here includes 1,524 MW of requested bids in the DLCO Control Zone and 1,402 MW of additional requested bids in the AEP and DAY Control Zones.

36 See Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period."

37 See Section 7, "Congestion," for an additional discussion of FTR revenue adequacy.

- **Revenue.** Revenues from the Annual FTR Auction are first distributed to ARR holders based on ARR target allocations. If that revenue is not sufficient to meet ARR target allocations, then revenues from Monthly FTR Auctions are used to make up any shortfall. For the 2005 to 2006 planning period, the ARR target allocations were $870 million while PJM collected $892 million from the combined Annual and Monthly FTR Auctions through the end of calendar year 2005, making ARRs revenue adequate. During the 2004 to 2005 planning period, the ARR target allocations were $345 million while PJM collected $385 million from the combined Annual and Monthly FTR Auctions, making ARRs revenue adequate.

- **Revenue Adequacy.** ARRs were 100 percent revenue adequate for both the 2005 to 2006 and the 2004 to 2005 planning periods. ARR holders will receive credits valued at $870 million during the 2005 to 2006 planning period, with an average hourly ARR credit of $1.67 per MWh. ARR holders received credits valued at $345 million during the 2004 to 2005 planning period, with an average hourly ARR credit of $1.17 per MWh.

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 allows a market valuation of FTRs. The 2005 FTR Auction Market results were competitive and succeeded in providing all qualified market participants with equal access to FTRs. A potential barrier to competition was removed by implementing the rules which explicitly allow that the ARRs with positive economic values (FTRs in newly integrated zones) follow load as load shifts among suppliers, although the fact that the underlying FTRs do not also follow load in the case of self-scheduled ARRs should also be addressed. FTRs were paid at 100 percent of the target allocation level for the 12-month planning period that ended May 31, 2005, and at 91 percent of the target allocation level for the first seven months of the planning period ending May 31, 2006. Although in the aggregate, FTRs provided a hedge against 100 percent of the target allocation level during the 12-month period that ended May 31, 2005, 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.

SECTION 2 – ENERGY MARKET, PART 1

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of other transaction types. For PJM, 2005 was a time of growth with two control zones being integrated into PJM Markets. The PJM Market Monitoring Unit's (MMU) analysis of the Energy Market treats these new zones as parts of existing markets as of the date of integration.

The MMU analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2005, including market size, concentration, residual supply index, price-cost markup, net revenue and prices. The MMU concludes that, despite ongoing concerns about market structure, the PJM Day-Ahead and Real-Time Energy Market performance results were competitive in 2005.

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 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.

During the last two calendar years, PJM has 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. In the *2005 State of the Market Report* the calendar year is 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]

1 PJM Market Monitoring Plan, OATT, Attachment M.

2 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

3 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

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 the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three 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).

- **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.

Overview

Market Structure

- **Supply.** During the June to September 2005 summer period, PJM Energy Markets received an average of 168,600 MW in net supply, including hydroelectric generation, excluding real-time imports or exports. The 2005 net supply represented an approximately 60,600 MW increase compared to the comparable 2004 summer period. The increase in 2005 was comprised of 39,000 MW from the Phase 3 AEP and DAY Control Zone integrations, 3,100 MW from the Phase 4 DLCO Control Area integration, 20,600 MW from the Phase 5 Dominion Control Zone integration, an average net increase of 200 MW of hydroelectric power generation and 2,300 MW from a net decrease in capacity from the Mid-Atlantic Region, the AP Control Zone and the ComEd Control Zone.

- **Demand.** The PJM system peak load in 2005 was 133,763 MW on July 26, 2005, a coincident summer peak load reflecting the Mid-Atlantic Region and the AP, ComEd, AEP, DAY, DLCO and Dominion Control Zones.[6] The PJM summer peak load in 2004 of 77,887 MW occurred prior to the integrations of the AEP, DAY, DLCO and Dominion Control Zones. If the 2004 summer peak load were adjusted to include the AEP, DAY, DLCO and Dominion zones for comparison purposes, the 2004 summer peak load of the combined area would have been 120,353 MW.[7]

- **Ownership 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

6 For the purpose of the *2005 State of the Market Report*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix H, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

7 This calculated 2004 peak load of the combined area was a total system coincident peak load and occurred on a different day and hour than the 2004 peak load for PJM.

segments. Specific geographic areas of PJM exhibited moderate to high levels of concentration when transmission constraints defined local markets. No evidence exists, however, that market power was exercised in these areas during 2005, both because of generator obligations to serve load and because of PJM's rules limiting the exercise of local market power.

- **Pivotal Suppliers.** A generation owner or group of generation owners is pivotal if the output of the owner's or owners' generation facilities is required in order to meet market demand. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The residual supply index (RSI) is a measure of the extent to which generation owners are pivotal suppliers. Like concentration ratios, the RSI is an indicator of market structure. When the RSI is less than 1.0, a generation owner or group of generation owners is pivotal. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.0 clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power. The RSI results are consistent with the conclusion that the PJM Energy Market results were competitive in both 2004 and 2005, with an average one pivotal RSI of 1.64 and 1.55, respectively. In 2005, a generation owner in the PJM Energy Market was pivotal for only 24 hours, less than 0.3 percent of all hours during the year. This represents an increase in pivotal hours from 2004, when a generation owner was pivotal in the Energy Market for eight hours, or less than 0.1 percent of all hours.

- **Ownership of Marginal Units.** The concentration of ownership of marginal units provides an additional dimension of the pivotal supplier results. The higher the level of concentration of ownership of marginal units the greater is the potential market power issue.

- **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 during the 11-month period ended November 30, 2005, were 2,065 MW from active load management, 1,619 MW from the Emergency Load-Response Program and 2,210 MW from the Economic Load-Response Program. There were 260 MW enrolled in both the Load-Response Program and in active load management. The 10,194 MW in total DSR resources, including additional programs reported by PJM customers in response to a survey, were approximately 8 percent of PJM's peak demand.

Market Conduct

- **Price-Cost Markup.** Price-cost markups are a measure of market power when they measure the impact of particular conduct on market outcomes. The price-cost markup reflects both participant conduct and the resultant market performance. The price-cost markup index is defined here as the difference between price and marginal cost, divided by price for the marginal units in the PJM Energy Market. The MMU has expanded and refined the analysis of markup measures. Overall, data on the price-cost markup are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2005, with markup index results averaging 0.3 percent for the calendar year.

- **Offer Capping.** PJM rules provide that PJM will offer cap units when their owners would otherwise have the ability to exercise local market power. Offer-capping levels remained steady in 2005. Offer capping is an effective means of addressing local market power.

- **Frequently Mitigated Units.** Rulings in 2005 by the United States Federal Energy Regulatory Commission (FERC) resulted in additional compensation as a form of scarcity pricing for units that were offer-capped more than 80 percent of their real-time run hours over the prior year.

Market Performance: Load and Locational Marginal Prices (LMPs)

- **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 average prices increased from 2004 to 2005. The simple, hourly average system LMP was 37.0 percent higher in 2005 than in 2004, $58.08 per MWh versus $42.40 per MWh. When hourly load levels are reflected, the load-weighted LMP of $63.46 per MWh in 2005 was 43.1 percent higher than 2004's $44.34. When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP was 1.5 percent higher in 2005 than in 2004, $45.02 per MWh compared to $44.34 per MWh. This means that, if it had not been for fuel cost increases, LMP would have been 1.5 percent higher in 2005 than in 2004.

  PJM average Real-Time Energy Market prices increased in 2005 over 2004 for several reasons, including, but not limited to, significant increases in fuel cost for the marginal units and in load. PJM load growth in 2005 reflected the geographic expansion created by the DLCO and Dominion integrations and hotter summer weather. The PJM system price was above $150 per MWh for only five hours in 2004; in 2005 it was above the $150 benchmark for 234 hours and above $200 per MWh for 35 hours.

Conclusion

The PJM MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for calendar year 2005, including aggregate supply and demand, concentration ratios, local market concentration ratios, residual supply indices, participation in demand-side response programs, price-cost markup and offer capping in this section of the report. The next section continues the analysis of the PJM Energy Market including measures of market performance.

Aggregate supply increased by about 60,600 MW when comparing the summer of 2005 to the summer of 2004 while aggregate peak load increased by 55,876 MW, retaining the general supply-demand balance from 2004 with a corresponding moderating impact on aggregate Energy Market prices. Market concentration levels remained moderate, relatively few hours exhibited pivotal suppliers and markups remained low. 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.

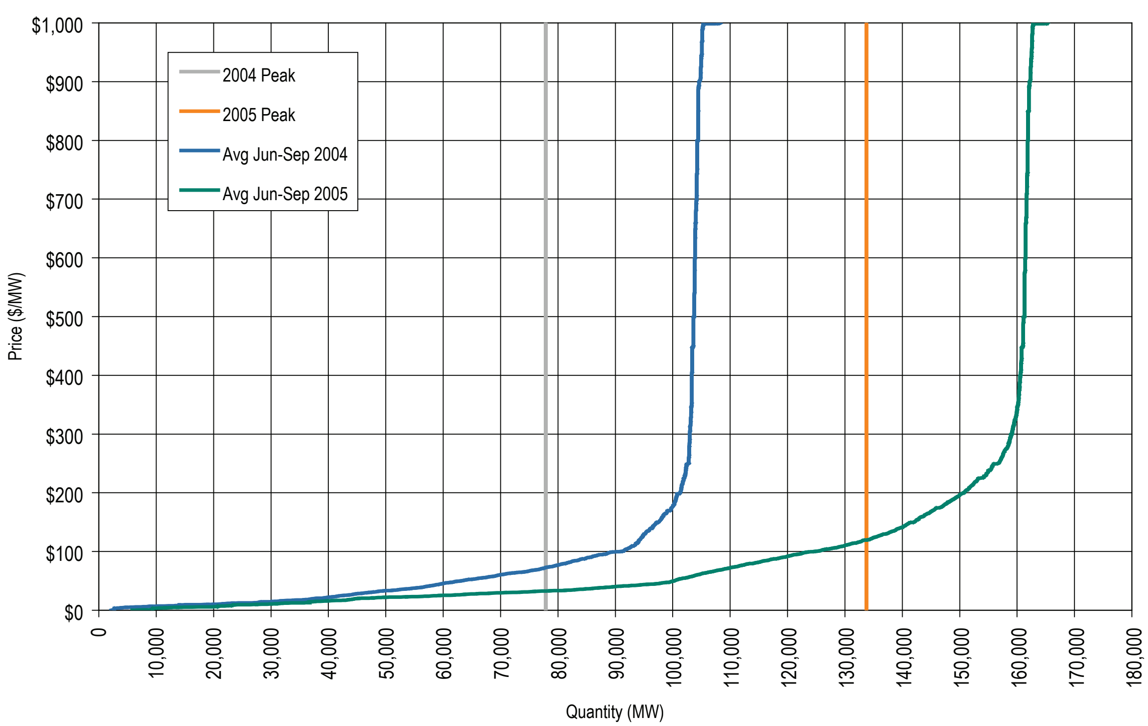
Energy Market results, including prices, for 2005 reflect supply-demand fundamentals. Significantly higher nominal and load-weighted prices are consistent with a competitive outcome as the higher prices reflect both higher input fuel costs and warmer summer weather. If fuel costs had been the same in 2005 as they had been in 2004, prices would have increased by 1.5 percent rather than the actual 37.0 percent increase in nominal average prices and the 43.1 percent increase in load-weighted average prices. While the existing structure of the Energy Market does not guarantee competitive outcomes, actual market performance results were reasonably competitive in 2005. Given the structure of the Energy Market, tighter markets or a change in participant behavior are potential sources of concern in the Energy Market.

Market Structure

Supply

During the June to September 2005 summer period, PJM Energy Markets received an hourly average of 168,600 MW in net supply, including hydroelectric generation, excluding real-time imports or exports. The 2005 net supply represented an approximately 60,600 MW increase compared to the comparable 2004 summer period. The increase in 2005 was comprised of 39,000 MW from the Phase 3 AEP and DAY Control Zone integrations, 3,100 MW from the Phase 4 DLCO Control Area integration, 20,600 MW from the Phase 5 Dominion Control Zone integration, an average net increase of 200 MW of hydroelectric power generation and 2,300 MW from a net decrease in capacity from the Mid-Atlantic Region, the AP Control Zone and the ComEd Control Zone. During the summer of 2005, the demand curve intersected the supply curve at a lower price level than would have occurred with less additional generation or with a different mix of additional generation. (See Figure 2-1.)[8]

Figure 2-1 - Average PJM aggregate supply curves: Summers 2004 and 2005



8 All figures in this paragraph have been rounded to the nearest 100 MW.

During the 12 months ended September 30, 2005,[9] approximately 1,540 MW of generation entered service in the Mid-Atlantic Region, AP and ComEd Control Zones. The additions consisted of 490 MW in upgrades to existing generation and 1,050 MW in new generation. After accounting for offsetting decreases from the derating of 250 MW of generation and the retirement of 3,560 MW, the net decrease in capacity was 2,270 MW. Of the 1,050 MW of new generation, 750 MW consisted of gas-fired combined-cycle generation, 240 MW consisted of fossil-fired steam, 20 MW consisted of diesel generation and 40 MW consisted of wind generation. Upgrades to existing facilities included 290 MW of fossil-fired steam units, 120 MW of gas-fired combined-cycle units, 10 MW of combustion turbine (CT) generation and 70 MW of nuclear generation. The ComEd Control Zone experienced the largest portion of retirements during the period with 3,200 MW out of 3,560 MW or almost 90 percent of the total retirements occurring in that Control Zone. Most of the 250 MW of derated generation was either fossil-fired steam or gas-fired combined-cycle units while the retired generation consisted of 3,060 MW of gas/oil-fired steam units and 500 MW of CTs.[10]

The net result was a slight shift to the left of the PJM aggregate supply curve as the costly retired generation was removed from the upper middle portion of the supply curve. The shape of the aggregate supply curve was changed only slightly by the new generation. Table 2-1 shows the units that retired for the entire PJM footprint from October 1, 2004, to September 30, 2005.[11]

Table 2-1 - Retired units: From October 1, 2004, through September 30, 2005

Unit Name	Installed Capacity (MW)	Unit Type	Retire Date
JC Riegel	27	CT	01-Jan-05
COM Collins 1	554	Steam	01-Jan-05
COM Collins 2	554	Steam	01-Jan-05
COM Collins 3	530	Steam	01-Jan-05
COM Collins 4	530	Steam	01-Jan-05
COM Collins 5	530	Steam	01-Jan-05
COM Electric Junction 31	59	CT	01-Jan-05
COM Electric Junction 32	59	CT	01-Jan-05
COM Electric Junction 33	59	CT	01-Jan-05
COM Lombard 32	32	CT	01-Jan-05
COM Lombard 33	32	CT	01-Jan-05
COM Sabrooke 31	25	CT	01-Jan-05
COM Sabrooke 32	25	CT	01-Jan-05
COM Sabrooke 33	24	CT	01-Jan-05
COM Sabrooke 34	13	CT	01-Jan-05
DPL Madison 1	11	CT	07-Jan-05
COM Crawford 31	56	CT	01-Mar-05
COM Crawford 32	58	CT	01-Mar-05
COM Crawford 33	56	CT	01-Mar-05
ACE Deepwater A	19	CT	01-May-05
PS Kearny 7	150	Steam	01-Jun-05
PS Kearny 8	150	Steam	01-Jun-05
ACE Vineland 7	8	Steam	17-Jun-05
Total	3,561		

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.
11 Retired unit parameters obtained from PJM.

The PJM supply curve (See Figure 2-1.) was extended with the additions of AEP and DAY in Phase 3, DLCO in Phase 4 and Dominion in Phase 5. Figure 2-1 compares the average supply curves for the pre and post Phase 3, 4 and 5 integrations. The pre Phase 3, 4 and 5 curve represents the average volume of offer MW for the summer period June through September 2004 while the post Phase 3, 4 and 5 integration curve represents the average volume of offer MW for June through September 2005. The average offered supply increased from about 110,000 MW for pre Phase 3, 4 and 5 integrations to about 170,000 MW for the post integration footprint.

Demand

In order to compare the 2005 summer peak load to the summer peak load in prior years, the change in the size of the PJM footprint had to be accounted for. PJM's geographic area was larger in the summer of 2005 than in prior years as the result of the Phase 3, 4 and 5 integrations of the AEP and DAY, DLCO and Dominion Control Zones, respectively. The comparison is presented in two ways. The peak load for the summer of 2005 is compared to what the summer peak load would have been in prior years if the larger footprint had been in place for those prior years. In addition, the peak load for the summer of 2005 is calculated without the Phase 3, 4 and 5 integrations compared to the PJM summer peak load for prior years for the same footprint.

Table 2-2 shows the actual coincident summer peak load for 2005 (including all integrations) and the calculated coincident summer peak loads for 2001 through 2004 for the same footprint based on an analysis of hourly loads in PJM and ComEd. Table 2-2 shows that the 2005 actual summer peak load of 133,763 MW was 13,410 MW more than the calculated 2004 summer peak load of 120,353 MW for the 2005 footprint.

Table 2-3 shows the calculated coincident summer peak load for PJM with the Phase 2 footprint for 2001 through 2003 and 2005 and the actual coincident summer peak loads for PJM in 2004 with the Phase 2 integration of the ComEd Control Zone. The 2005 calculated coincident summer peak load of 85,322 MW without the Phase 3, 4 and 5 integrations was 7,435 MW higher than the actual 2004 PJM coincident summer peak load of 77,887 MW, for the same footprint.

When comparable footprints are used, the summer peak demand in 2004 was lower than the summer peak demand in 2003 or 2002.

Table 2-2 - Actual 2005 summer peak demand and calculated Phase 3, 4 and 5 coincident summer peak demand: For 2001 through 2004

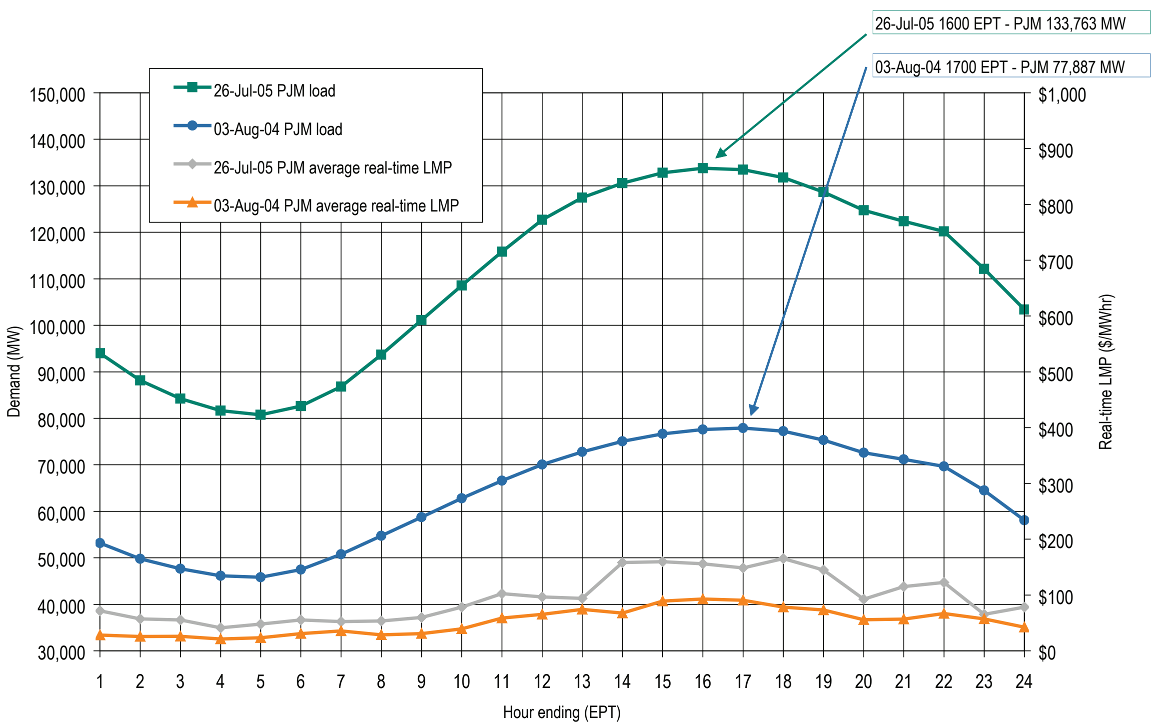
	Date	EPT Hour Ending	PJM Load (MW)	Difference (MW)
2001	09-Aug-01	1500	126,099	NA
2002	01-Aug-02	1700	128,135	2,036
2003	21-Aug-03	1700	126,288	(1,847)
2004	09-Jun-04	1700	120,353	(5,935)
2005	26-Jul-05	1600	133,763	13,410

Table 2-3 - Calculated 2005 Phase 2 coincidental summer peak demand: For 2001 through 2003 and 2005 and actual Phase 2 coincident summer peak demand for 2004

	Date	EPT Hour Ending	PJM Load (MW)	Difference (MW)
2001	09-Aug-01	1500	83,713	NA
2002	01-Aug-02	1700	84,795	1,082
2003	21-Aug-03	1700	81,992	(2,803)
2004	03-Aug-04	1700	77,887	(4,105)
2005	26-Jul-05	1600	85,322	7,435

The actual, unadjusted PJM coincident summer peak demand based on the actual footprint in each year increased from 77,887 MW in 2004 to 133,763 MW in 2005. The hourly load and average PJM LMP are shown for these two summer peak days in Figure 2-2.

Figure 2-2 - PJM summer peak-load comparison: Tuesday, July 26, 2005, and Tuesday, August 3, 2004



The unadjusted, actual summer peak demands for PJM, based on the actual footprint in each year, are shown in Table 2-4 for the years 2001 through 2005. The 2001 PJM footprint is the footprint for the PJM Mid-Atlantic Region. The AP Control Zone was integrated prior to the summer peak period in 2002; the ComEd Control Zone was integrated prior to the summer peak period in 2004 and AEP, DAY, DLCO and Dominion Control Zones were integrated prior to the 2005 summer peak period.

Table 2-4 - Actual PJM footprint summer peak loads: From 1999 to 2005

	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

Market Concentration

During all phases of 2005, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[12] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. A generation owner is pivotal if the output of the owner's generation facilities is needed to meet load.[13] Further, specific geographic areas of PJM exhibit moderate to high concentration that may be problematic when transmission constraints exist. No evidence suggests that market power was exercised in these areas during 2005, primarily because of generation owners' obligations to serve load and PJM rules limiting the exercise of local market power. If those obligations were to change, however, the market-power-related incentives would change as a result.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their impact on price. The 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. This analysis reflects the evolving nature of the PJM Markets during 2004 and 2005. In 2004, the PJM Markets encompassed the Mid-Atlantic Region and the AP Control Zone in Phases 1 and 2 and in Phase 3, PJM Markets incorporated the ComEd, AEP and DAY Control Zones. In 2005, the PJM Markets encompass all 2004 elements, plus the DLCO Control Zone in Phase 4 and the Dominion Control Zone in Phase 5. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators located in each geographic footprint, adjusted for hourly net imports by owner. (See Table 2-5.)

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

13 See RSI calculations in Section 2, "Energy Market, Part 1," for a direct measure of whether generation owners were pivotal.

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.

In addition to the aggregate PJM calculations, HHIs were calculated for selected transmission-constrained areas of PJM to provide an indication of the level of concentration that exists when specific areas within PJM are isolated from the larger PJM Market by transmission constraints.

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.[14]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2004 and 2005 was moderately concentrated. (See Table 2-5.) Based on the hourly Energy Market measure, overall market concentration varied from 857 to 1788 in 2004 and from 855 to 1854 in 2005.[15]

Table 2-5 - PJM hourly Energy Market HHI: Calendar years 2004 to 2005[16]

	Minimum	Average	Maximum
Phases 1 and 2	857	1182	1500
Phase 3	1164	1448	1788
Calendar Year 2004	857	1249	1788
Phase 4	1087	1428	1854
Phase 5	855	1200	1565
Calendar Year 2005	855	1275	1854

14 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.
15 The 2004 HHI results reported in the *2004 State of the Market Report* were incorrect. The corrected 2004 HHI results are reported here.
16 Statistics shown in the tables have been derived from the underlying data and may not exactly match statistics calculated using the values shown due to rounding.

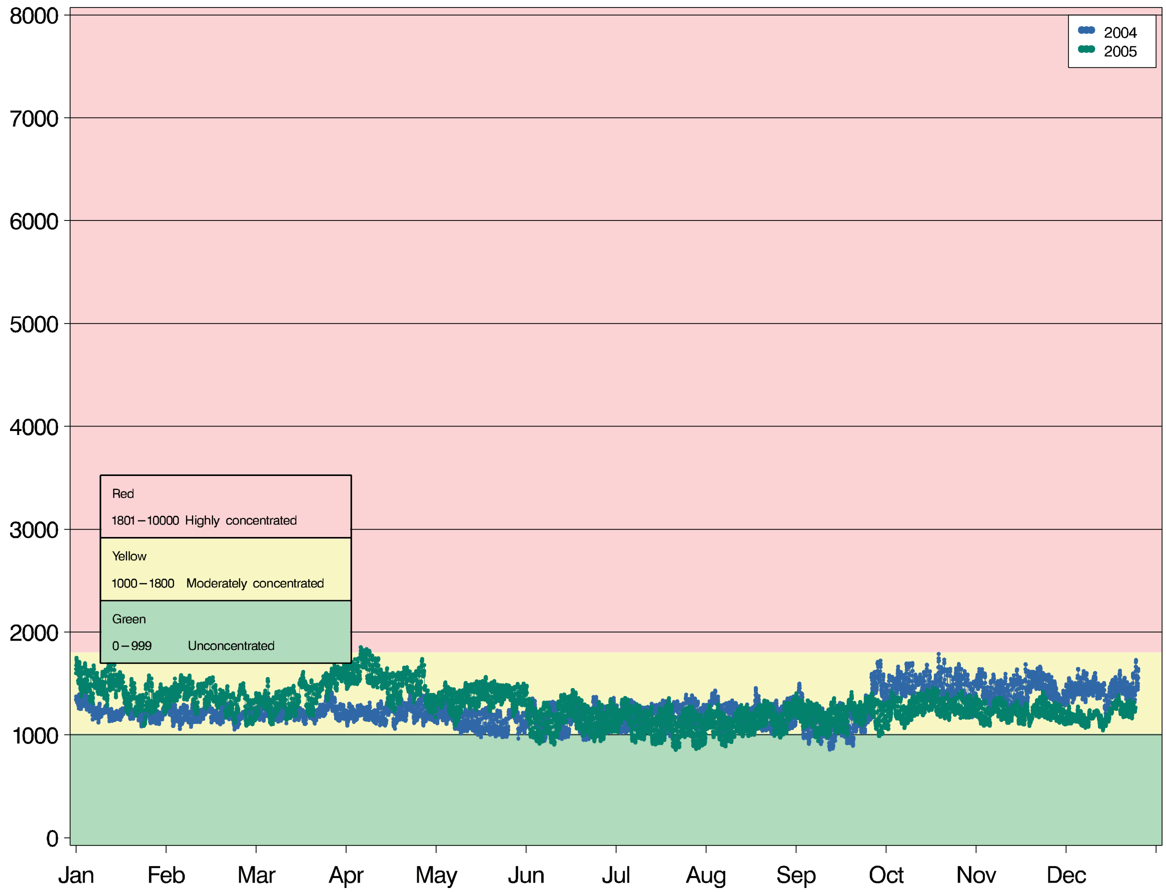
Table 2-6 includes 2004 and 2005 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated. HHIs are calculated for facilities located in PJM; imports are not included.

Table 2-6 - PJM hourly Energy Market HHI (By segment): Calendar years 2004 to 2005

	Statistic	Base	Intermediate	Peak
Phases 1 and 2	Maximum	1594	6292	10000
	Average	1355	2065	4604
	Minimum	1209	866	1143
Phase 3	Maximum	2001	6352	10000
	Average	1762	3761	5294
	Minimum	1522	1590	931
Calendar Year 2004	Maximum	2001	6352	10000
	Average	1467	2565	4839
	Minimum	1209	866	931
Phase 4	Maximum	1995	6920	10000
	Average	1659	3705	5011
	Minimum	1399	1032	827
Phase 5	Maximum	1593	8257	10000
	Average	1362	2793	4437
	Minimum	1232	731	717
Calendar Year 2005	Maximum	1995	8257	10000
	Average	1451	3078	4612
	Minimum	1232	731	717

Figure 2-3 presents detailed hourly HHI results for the PJM Energy Market summarized in Table 2-5.

Figure 2-3 - PJM hourly Energy Market HHI: Calendar years 2004 and 2005



Local Market Concentration and Frequent Congestion

With the marked increased in total congestion-event hours in PJM from 2004 to 2005, several geographic areas in the PJM Mid-Atlantic Region, the Western Region and the Southern Region experienced frequent congestion and showed high local market concentration: namely the PSEG, AP, Met-Ed, BGE, ComEd, PECO, PENELEC, Dominion, AEP and AECO Control Zones.[17] Other areas, including the DPL, DLCO, JCPL, PPL, RECO, PEPCO and DAY Control Zones, had a limited amount of constrained hours during 2005.[18]

- **PSEG North.** In calendar year 2005, the number of constrained hours increased from 456 hours in 2004 to 784 hours, with 56 percent of all constrained hours occurring during on-peak periods. The Roseland-Cedar Grove 230 kV line contributed 364 hours of congestion, representing an increase of 143 percent from 2004 when it had been constrained for 150 hours. The Cedar Grove–Clifton 230 kV line also experienced an increase in congestion from 37 hours in 2004 to 176 hours in 2005. Twenty

17 For 2005, any area that experienced congestion for more than 100 hours was analyzed for market concentration and the effect of each constraint on load in the constrained area. HHIs were measured based on installed capacity in the constrained area for calendar year 2005.

18 A constrained hour is defined as any hour during which one or more facilities are congested. A congestion-event hour is defined as the total number of constrained hours for a particular facility. Constraints are often simultaneous and, therefore, the sum of congestion-event hours can exceed the sum of constrained hours in a zone.

other constraints, each occurring for less than 100 hours, accounted for the remainder of the congestion. While both of these lines experienced increases from 2004, over 85 percent of the constrained hours came after the installation of a third transformer at Branchburg on April 25, 2005. In March 2004, the derating of the Branchburg 500/230 kV transformer in northcentral PSEG, contributed to the increase in congestion at Branchburg. The increased Branchburg 230/500 kV transformer congestion significantly limited the flow of power into the northern PSEG area, thus eliminating overloads that might otherwise have occurred, such as the Roseland–Cedar Grove and Cedar Grove–Clifton 230 kV lines. On average, the Roseland-Cedar Grove line and the Cedar Grove-Clifton line affected 541 MW and 703 MW of load, respectively.[19] The 2005 gross congestion cost associated with the Roseland-Cedar Grove 230 kV constraint totaled $44.9 million, while the Cedar Grove-Clifton 230 kV constraint totaled $28.8 million.[20] Both the Roseland-Cedar Grove and the Cedar Grove-Clifton constraints resulted in high market concentration and HHIs of 8198 and 7582, respectively.

- **PSEG Northcentral.** In 2005, the number of constrained hours decreased from 1,121 hours in 2004 to 881 hours, with 71 percent of all constrained hours occurring during on-peak periods. The Branchburg 500/230 kV transformer constraint, which accounted for 90 percent of congestion in the area during 2004, was significantly decreased from 1,005 hours to 412 hours in 2005. The installation of a third transformer on April 25, 2005, which was necessary due to the March 2004 derating of the original transformers, was the primary cause for the decrease in congestion at Branchburg. In 2004, the derating had limited the flow through the transformer and the Branchburg constraint had reduced the occurrence of other constraints such as the Edison-Meadow Road 138 kV. In 2005, the frequency of the Edison-Meadow Road 138 kV line increased from 33 hours to 191 hours and 93 percent of the hours occurred after April 25. The Branchburg – Readington 230 kV line was also constrained for 175 hours, an increase from 108 hours in 2004. Five additional constraints contributed to the remainder of congestion in this area. On average, the Branchburg transformer affected 565 MW of load, the Edison-Meadow Road 138 kV line affected 302 MW of load, and the Branchburg-Readington 230 kV line affected 448 MW of load. The 2005 gross congestion cost for the Branchburg transformer was $125.2 million, the Edison-Meadow Road line was $13.5 million, and the Branchburg-Readington line was $30.1 million. All three constraints resulted in high market concentration with HHIs of 2998, 8070 and 8198, respectively.

- **Eastern Interface.** During 2005, congestion on the Eastern Interface decreased from 221 hours to 103 hours. Seventy-four percent of all congestion occurred during on-peak periods. The Eastern Interface affected, on average, 5,940 MW of load. The 2005 gross congestion cost associated with the Eastern Interface was $34.7 million. Market concentration in the affected area was moderate with an HHI of 1575.

- **Delmarva Peninsula (DPLS).** Congestion on the Delmarva Peninsula increased from 320 constrained hours to 402 hours, with 56 percent occurring during on-peak periods. However, no single constraint occurred for more than 100 hours during 2005.

- **Delaware North (SEPJM/DPLN).** In 2005, the northern area of Delaware in the DPL Control Zone experienced a decrease in constrained hours from 102 hours to 49 hours.

19 The affected load calculation for 2005 was derived by taking the sum of the product of MW and distribution factor. Distribution factors were limited to those greater than, or equal to, 3 percent on the high-priced side of the constraint.

20 The gross congestion cost calculation is equal to the product of the hourly affected load and the average hourly marginal value of each real-time transmission constraint.

- **Southern New Jersey (AECO).** The southern New Jersey (SNJ) subarea of the AECO Control Zone experienced 970 hours of congestion, with one constraint, the Laurel-Woodstown 69 kV line, accounting for 91 percent of all congestion in the area. The Laurel-Woodstown line was constrained for 879 hours, an increase of 119 percent from 2004, with 75 percent of all hours occurring during on-peak periods. Nine other constraints, each occurring for less than 100 hours, contributed to the remainder of congestion in the area. On average, the Laurel-Woodstown constraint affected 81 MW of load. The 2005 gross congestion cost associated with the Laurel-Woodstown constraint was $24.2 million. High market concentration resulted from the Laurel-Woodstown constraint with an HHI of 9012.

- **Cedar Subarea (AECO).** In 2005, the Cedar subarea in the AECO Control Zone continued to be frequently constrained. Two constraints accounted for most of the congestion in the area. The 749 constrained hours experienced during 2005 represented a small increase from the 742 hours that had been experienced in 2004. Seventy-one percent of all constrained hours occurred during on-peak periods. In 2005, the Cedar interface was constrained 438 hours, a decrease from 605 hours in 2004. Additionally, the Absecon-Lewis 69 kV line constraint appeared in 2005 and was constrained for 283 hours. On average, the Cedar interface and the Absecon-Lewis line isolated 79 MW and 97 MW of load, respectively. The 2005 gross congestion cost for the Cedar interface was $5.7 million, while the Absecon-Lewis line was $5.1 million. Each constraint defined highly concentrated markets with HHIs of 10000.

- **Met-Ed West.** In 2005, the Met-Ed west subarea was constrained for 313 hours, an increase from 262 hours in 2004. Eighty-seven percent of all congestion in the area occurred during on-peak periods. The Bair-Hill 115 kV line was constrained for 225 hours in 2005, up from 27 hours in 2004. Seven other constraints, each occurring for less than 100 hours, accounted for the remaining congestion in this area. The Bair-Hill 115 kV line affected, on average, 106 MW of load. The 2005 gross congestion cost associated with the Bair-Hill line was $2.4 million. High market concentration and an HHI of 10000 resulted from this constraint.

- **PENELEC.** In 2005, the northcentral and northwest subareas of the PENELEC Control Zone were constrained for 264 hours and 170 hours, respectively. The northcentral subarea experienced 30 percent of its constrained hours during peak periods, while the northwest subarea experienced 21 percent. Two constraints contributed to the majority of congestion in these areas. The Garman – Glory 115 kV line was constrained 105 hours, up from 29 hours in 2004. Congestion on the Erie West 345/115 kV transformer also increased from one hour in 2004 to 170 hours in 2005. On average, the Garman-Glory line affected 58 MW of load and the Erie West transformer affected 142 MW of load. The 2005 gross congestion cost associated with the Garman-Glory line was $670,000 and $7 million was associated with the Erie West transformer. High market concentration resulted from both the Garman-Glory line and the Erie West transformer with HHIs of 9773 and 3306, respectively.

- **BGE Control Zone.** In 2005, the BGE Control Zone experienced 144 constrained hours and 86 percent of the hours occurred during on-peak periods. The 144 constrained hours represented a 92 percent increase in constrained hours from 75 hours in 2004. The Center-Westport 115 kV line was constrained 104 hours in 2005, compared to 48 hours in 2004. On average, the Center-Westport line affected 264 MW of load. The 2005 gross congestion cost associated with the Center-Westport line was $5.6 million dollars. The Center-Westport line created a highly concentrated market with an HHI of 7221.

- **PECO Control Zone.** In 2005, the PECO Control Zone experienced 212 constrained hours and 82 percent of the hours occurred during on-peak periods. The 212 hours represented a 51-hour increase from 2004. The Chichester-Linwood 230 kV line was constrained 128 hours and did not occur in prior years. Thirteen other constraints, each occurring less than 100 hours, contributed to the remainder of the constrained hours. The Chichester-Linwood line affected 901 MW of load. The 2005 gross congestion cost associated with this line was $12 million. The constraint created a highly concentrated market with an HHI of 2988.

- **ComEd Control Zone.** In 2005, the ComEd Control Zone experienced 401 constrained hours and 84 percent of the hours occurred during on-peak periods. This was a substantial increase from 130 hours in 2004, and only 5 percent of the hours in 2005 occurred prior to May 1, 2005. The largest contributor to the 2005 congestion was the Cherry Valley 345/138 kV transformer, which occurred for 104 hours in 2005 and only five hours in 2004. On average, the Cherry Valley transformer affected 478 MW of load. The 2005 gross congestion cost associated with the transformer was $4.3 million dollars. The market defined by the Cherry Valley transformer was highly concentrated with an HHI of 5383.

- **Dominion Control Zone.** In 2005, the Dominion Control Zone experienced 570 constrained hours and 83 percent of the hours occurred during on-peak periods. Two constraints accounted for over half of the constrained hours. The Alta Vista-Dominion 115 kV line was constrained for 173 hours and the Beechwood-Kerr Dam 115 kV line was constrained 128 hours. On average, the Alta Vista-Dominion constraint affected 45 MW of load, while the Beechwood-Kerr Dam constraint affected 55 MW of load. The 2005 gross congestion cost associated with the Alta Vista-Dominion constraint was $4.1 million and $2 million was associated with the Beechwood-Kerr Dam constraint. Each constraint defined a highly concentrated market with HHIs of 10000.

- **AEP Control Zone.** In 2005, the AEP Control Zone experienced 1,772 constrained hours and 42 percent of the hours occurred during on-peak periods. AEP congestion in 2005 increased substantially from 2004, when there were only 165 constrained hours, but was measured only during the three-month period from the AEP integration with PJM. During the same three-month period in 2005, AEP experienced 374 constrained hours in 2005 compared to 165 hours in 2004. The three major constraints that contributed to the 2005 congestion total were: the Cloverdale-Lexington 500 kV line, the Kanawha River–Matt Funk 345 kV line and the Mahans Lane-Tidd 138 kV line. The Cloverdale-Lexington line was constrained for 31 hours in 2004, or 19 percent of total hours, and 508 hours during 2005, or 29 percent of total hours. The Kanawha River-Matt Funk line was constrained 51 hours in 2004, or 31 percent of total hours, and 401 hours in 2005, or 23 percent of total hours. The Mahans Lane-Tidd line was constrained 69 hours in 2004, or 42 percent of total hours, and 448 hours in 2005, or 25 percent of total hours. On average, the Cloverdale-Lexington line affected 3,327 MW of load, the Kanawha River-Matt Funk line affected 1,694 MW of load, and the Mahans Lane-Tidd line affected 160 MW of load. The 2005 gross congestion cost associated with each of these constraints was $157.6 million, $150.8 million and $11.9 million, respectively. The Cloverdale-Lexington line and the Kanawha River-Matt Funk created moderately concentrated markets that have HHIs of 1078 and 1066, respectively. The Mahans Lane-Tidd line creates a highly concentrated market with an HHI of 10000.

- **AP Control Zone.** In 2005, the AP Control Zone experienced frequent congestion totaling 2,746 constrained hours.[21] Fifty-four percent of the constrained hours occurred during on-peak periods. In 2004, the AP Control Zone experienced 336 constrained hours. Congestion on the Krendale–Seneca 138 kV line, located in the northern AP subarea, increased to 173 hours from 14 hours in 2004. On average, the Krendale-Seneca line affected 100 MW of load. The 2005 gross congestion cost associated with this line was $3.2 million. The Krendale-Seneca line created a moderately concentrated market with an HHI of 1296.

  In addition to the northern AP congestion, three facilities located in the eastern AP subarea each experienced increases in congestion and each totaled more than 100 hours. The Bedington-Nipetown 138 kV line increased from 21 hours to 213 hours in 2005. The Bedington 500/138 kV transformer increased from 37 hours to 144 hours in 2005. The Meadow Brook 500/138 kV transformer increased from 11 hours to 135 hours in 2005. On average, the Bedington and Meadow Brook transformers affected 383 and 389 MW of load, respectively while the Bedington-Nipetown line affected 160 MW of load. The 2005 gross congestion cost for the Bedington, Meadowbrook and Bedington-Nipetown facilities was $15 million, $40.9 million and $9 million, respectively. All three constraints created highly concentrated markets with HHIs ranging from 3821 to 5684.

  Similarly, the central AP subarea also had three facilities on which congestion was increased and each totaled more than 100 hours. The Elrama-Mitchell 138 kV line increased from 59 hours to 137 hours. The Mitchell-Shepler Hill 138 kV line increased from 42 hours to 214 hours. The Charleroi-Mitchell 138 kV line increased from 10 to 318 hours. On average, the Elrama-Mitchell line affected 1,417 MW of load, the Mitchell-Shepler Hill line affected 17 MW of load, and the Charleroi-Mitchell line affected 130 MW of load. The 2005 gross congestion cost associated with these respective lines was $18.8 million, $6.2 million and $723,000. The Charleroi-Mitchell and the Mitchell-Shepler Hill constraints each created highly concentrated markets with an HHI of 5386 and 10000, respectively. The Elrama-Mitchell line created an unconcentrated market with an HHI of 916.

  Finally, three other large constraints contributed significantly to the AP Control Zone total. Congestion on the Mt. Storm-Pruntytown 500 kV line increased from zero hours in 2004, to 696 hours in 2005. Additionally, congestion on the Doubs-Mt. Storm 500 kV line increased from 87 hours in 2004, to 422 hours in 2005. Congestion on the Doubs transformers also increased from 85 hours in 2004, to 526 hours in 2005. On average, the Mt. Storm-Pruntytown line had the largest affected load total of 10,094 MW followed by the Doubs-Mt. Storm line, which affected 4,798 MW of load. The Doubs transformers affected 396 MW of load. The 2005 gross congestion cost associated with each of these constraints was $765.9 million, $672.1 million and $99.9 million. Market concentration was moderate for both the Mt. Storm-Pruntytown and Doubs-Mt. Storm with HHIs of 1048 and 1042, respectively. The Doubs transformers created a highly concentrated market with an HHI of 4841.

- **Western Interface.** In 2005, congestion on the Western Interface increased from 63 hours to 216 hours. Sixty-two percent of all constrained hours occurred during on-peak periods. The Western Interface, on average, affected 9,388 MW of load. The 2005 gross congestion cost associated with the Western Interface was $139.7 million. Market concentration was moderate overall with an HHI of 1130.

21 The AP Control Zone totals reported here exclude the contribution from the Wylie Ridge 500/230 kV transformer and the Bedington – Black Oak 500 kV line. These constraints are analyzed separately due to their size and effect on the PJM system.

- **5004/5005 Interface.** In 2005, congestion on the 5004/5005 interface increased from 19 hours to 567 hours.[22] Fifty-three percent of all constrained hours occurred during on-peak periods. The 5004/5005 interface, on average, affected 3,009 MW of load. The 2005 gross congestion cost associated with the 5004/5005 interface was $176.6 million. Market concentration was moderate overall with an HHI of 1451.

- **Kammer Transformer (AEP).** In 2005, congestion on the Kammer 765/500 kV transformer increased from 84 hours to 1,332 hours. Forty percent of all hours occurred during on-peak periods. In 2004, 100 percent of congestion on the Kammer transformer came after the integration of AEP on October 1. Comparing the last three months of 2005, the Kammer transformer was constrained 572 hours or 43 percent of the 2005 Kammer total. On average, the Kammer transformer affected 3,847 MW of load. The 2005 gross congestion cost associated with the transformer was $608.7 million. The market defined by the Kammer transformer was unconcentrated with an HHI of 916.

- **Bedington - Black Oak (AP).** In 2005, the Bedington – Black Oak 500 kV line was constrained for 1,314 hours, with 45 percent of congestion occurring during on-peak periods. Congestion was up from 2004 when it had been constrained for 1,131 hours. The location and size of this line contributed to its substantial impact on the entire PJM system, with an average affected load of 3,912 MW and a total gross congestion cost of $921.6 million. The Bedington – Black Oak 500 kV line caused moderate concentration in the affected area with an HHI of 1083.

- **Wylie Ridge (AP).** During 2005, congestion on the Wylie Ridge 345/500 kV transformers more than doubled from 642 hours in 2004 to 1,399 hours. Thirty-one percent of all congestion occurred during on-peak periods. The Wylie Ridge transformers affected approximately 1,463 MW of load and had a total gross congestion cost of $289.6 million. The area affected by this constraint was unconcentrated, with an HHI of 824.

Pivotal Suppliers

In addition to the aggregate PJM and local market HHI calculations used to measure market concentration, the RSI is a measure of the extent to which one or more generation owners are pivotal suppliers in the PJM Energy Market. A generation owner or group of generation owners is pivotal if the output of the owner's or owners' generation facilities is required in order to meet market demand. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. For a given level of market demand, the RSI compares the market supply net of the generation supply owned by a specified owner or group of owners, to the market demand. The RSI for generation owner "*i*" is [($Supply_m$ - $Supply_i$)/($Demand_m$)], where $Supply_m$ is total supply in the energy market including net imports.[23] $Supply_i$ is the supply owned by the individual generation owner or group of generation owners "*i*" and $Demand_m$ is total market demand. If the RSI is greater than 1.0, the supply of the specific generation owner or group of owners is not needed to meet market demand and that generation owner or group of generation owners has a reduced ability to influence market price. If the RSI is less than 1.0, the supply owned by the specific generation owner or group of owners is needed to meet market demand and the generation owner or group of generation owners is pivotal. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.0 for a single generation owner clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power.

22 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.

23 Total supply in the Energy Market is the sum of all offers to provide energy. If net imports are negative (exports), they are treated as additional demand.

The RSI was calculated hourly for every individual generation owner. The overall PJM Energy Market RSI is the minimum RSI for each hour, equal to the RSI for the largest generation owner in each hour. (See Table 2-7.) The RSI was also calculated for the largest two generation owners together in order to determine the extent to which two suppliers were jointly pivotal. These results are reported in Table 2-8.

PJM RSI Results

The RSI results reported in Table 2-7 are consistent with the conclusion that PJM Energy Market results were competitive in both 2004 and 2005, with an average hourly RSI of 1.64 and 1.55, respectively.[24] In 2005, a generation owner in the PJM Energy Market was pivotal for only 24 hours, less than 0.3 percent of all hours during the year. This represents an increase in pivotal hours from 2004, when a generation owner was pivotal in the Energy Market for eight hours, or less than 0.1 percent of all hours. The 24 hours when a single generation owner was pivotal in the Energy Market occurred during July and August of 2005, when demand exceeded 130,000 MW. Further, the minimum RSI for the two pivotal supplier test was 0.80 while the average two pivotal RSI was 1.27. There were 861 hours in which the two pivotal RSI was less than 1.0. Ninety-five percent of the jointly pivotal hours occurred between June 6, 2005, and September 22, 2005. The probability of having one or more pivotal suppliers increases during periods of peak demand.

Table 2-7 - PJM RSI statistics: Calendar years 2004 to 2005

	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Phases 1 and 2	45	8	0.12%	1.62	0.96
Phase 3	0	0	0.00%	1.67	1.14
Calendar Year 2004	45	8	0.09%	1.64	0.96
Phase 4	0	0	0.00%	1.57	1.10
Phase 5	262	24	0.41%	1.52	0.97
Calendar Year 2005	262	24	0.27%	1.55	0.98

Table 2-8 shows two pivotal supplier RSI results.

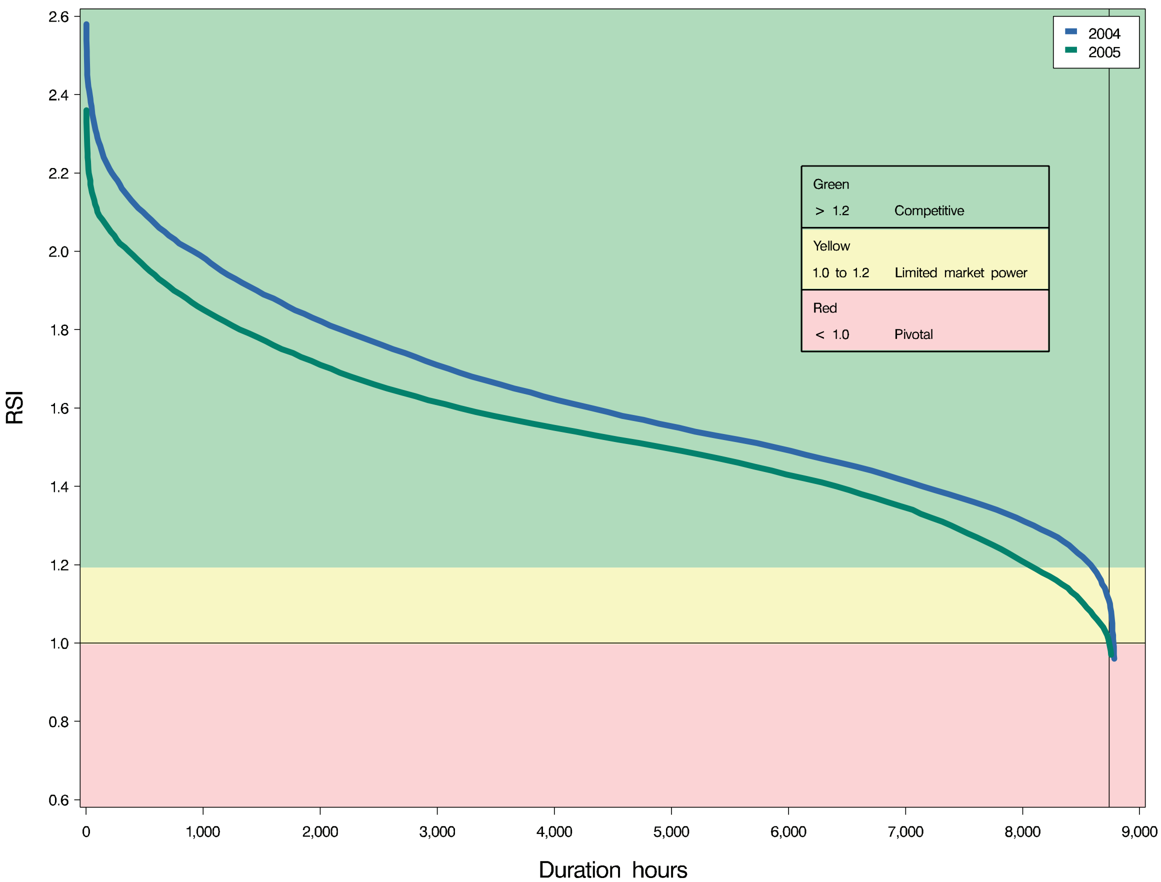
Table 2-8 - PJM top two supplier RSI statistics: Calendar years 2004 to 2005

	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Phases 1 and 2	830	194	2.95%	1.35	0.81
Phase 3	138	22	1.00%	1.34	0.90
Calendar Year 2004	968	216	2.46%	1.35	0.81
Phase 4	350	43	1.49%	1.28	0.95
Phase 5	1502	818	13.91%	1.27	0.80
Calendar Year 2005	1852	861	9.83%	1.27	0.80

24 While there is no defined RSI threshold, the California Independent System Operator (CAISO) has used an energy market RSI value exceeding 1.20 to 1.50 as an indicator of a reasonably competitive market.

Figure 2-4 shows the one pivotal supplier RSI duration curves for PJM during 2004 and 2005. The curve shows the limited number of hours below 1.0 in both 2004 and 2005.

Figure 2-4 - PJM RSI duration curve: Calendar years 2004 and 2005



Ownership of Marginal Units

Table 2-9 presents the ownership distribution of marginal units. The table shows the percent of the five-minute intervals for which one or more companies owned the marginal unit, based on data for all units that were on the margin for one or more five-minute intervals during the specified year. For example, in 2004, one company owned the marginal unit from 20 percent to 35 percent of the time. In 2005, two different companies each owned the marginal unit from 15 percent to 20 percent of the intervals. In other words, together, two companies owned the marginal unit from 30 percent to 40 percent of the time. The higher the proportion of the time that a small number of companies own the marginal unit, the greater the potential market power concern.

Table 2-9 - Ownership of marginal units (By number of companies in frequency category): Calendar years 2001 to 2005

	Number of Companies that Owned the Marginal Unit in Frequency Category:				
	5% or Less	5% to 10%	10% to 20%	15% to 20%	20% to 35%
2001	14	4	2	2	0
2002	19	4	2	2	0
2003	20	4	1	2	0
2004	27	6	0	1	1
2005	45	5	1	2	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 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 all or most customers, or their designated proxies, 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. 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 smaller scale retail and residential applications. 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 those tradeoffs.

A functional demand side of wholesale energy markets 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 tend to induce more competitive behavior among suppliers and to limit their 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 PJM Open Access Transmission Tariff (PJM Tariff) and to the Amended and Restated Operating Agreement (PJM Operating Agreement) to establish a multiyear Economic Load-Response Program (the Economic Program).[25] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[26] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007.[27]

The PJM Economic Load-Response Program provides 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 whereby customers do not require mandated payments but where customers see and react to market signals or where customers enter into contracts with intermediaries who see and react to market signals on their behalf. 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.[28] On March 1, 2002, PJM filed amendments to the PJM Tariff and to the PJM Operating Agreement to establish a permanent Emergency Load-Response Program (the Emergency Program).[29] 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.[30] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[31]

25 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1326-000 (March 15, 2002).
26 99 FERC ¶ 61,227 (2002).
27 *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER04-1193-000 (October 29, 2004).
28 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).
29 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).
30 99 FERC ¶ 61,139 (2002).
31 *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

Emergency Program

The number of currently active sites with associated MW in the Emergency Program is shown in Table 2-10.[32] As of November 30, 2005, there were 1,618.8 MW of resources active in the Emergency Program.[33] This is a 4 percent increase from 1,557.9 MW at the end of 2004.[34]

Table 2-10 - Currently active participants in the Emergency Program

	Currently Active by Year Enrolled		Cumulative Total	
	Sites	MW	Sites	MW
2001	NA	NA	NA	NA
2002	64	514.6	64	514.6
2003	103	148.1	167	662.7
2004	3,706	895.3	3,873	1,557.9
2005	120	60.9	3,885	1,618.8

Table 2-11 presents the zonal distribution of DSR capability in the Emergency Program as of November 30, 2005.[35] One zone includes 95 percent of all available sites and 53 percent of all available MW in the Emergency Program. In addition, 95 percent of sites and 60 percent of MW of Emergency Program capabilities are located in the Western Region of PJM.

32 The data on currently active sites and MW differ from that reported in the *2004 State of the Market Report* because corrections were made to the DSR source data by PJM.

33 For both Emergency and Economic programs the results reported for 2005 are based on the 11 months, January through November, only that data was available at the end of the calendar year. Under the terms of the Operating Agreement, participants have 60 days to submit data to PJM, after which LSE and EDC have an additional 10 days to verify these data. The results for 2004 reported in the table are based on 12 months of data, but the *2004 State of the Market Report* was based on the nine months of 2004 data available at that time. The 2002 program began on June 1, 2002. The 2002 data are based on the five-month period, June through October which represents all available data.

34 The numbers of registered sites and currently active sites with associated MW for Emergency and Economic programs for 2001 are not available.

35 In Table 2-11, Table 2-14 and Table 2-16 pricing zones include a UGI zone consistent with the practice of the PJM DSR department.

Table 2-11 - Current zonal capability in the Emergency Program: Eleven months ended November 30, 2005

	Sites	MW
AECO	3	4.0
AEP	0	0.0
AP	12	74.5
BGE	15	112.9
ComEd	3,681	856.3
DAY	0	0.0
DLCO	2	41.5
Dominion	0	0.0
DPL	6	17.3
JCPL	8	3.3
Met-Ed	7	6.6
PECO	76	293.0
PENELEC	14	7.7
PEPCO	10	7.5
PPL	27	163.4
PSEG	23	30.6
RECO	0	0.0
UGI	1	0.3
Total	3,885	1,618.8

During the summer of 2005, activity under the Emergency Program occurred on five days: July 25, August 3, August 4, August 5 and August 14. The maximum hourly reduction was 205 MW. Activity occurred during hours when real-time LMPs were between $68 per MW and $206 per MW. The total of individual hours of Emergency Program reductions in 2005 was 23 and all occurred between the hours ending 1500 EPT and 1900 EPT.

The total MWh of load reductions and the associated payments under the Emergency Program are shown in Table 2-12.[36] Load reduction levels decreased in 2003 by 91 percent from 551 MW in 2002.[37] There was no activity in the program during 2004 due to the mild weather conditions and associated prices. At 3,662 MWh, 2005 had the largest load reduction level since the program began. In the 11-month period ended November 30, 2005, payments under the program were $508 per MWh. There were 2 MWh of actual load reduction per currently active MW in the Emergency Program for the 11-month period ended November 30, 2005.

Table 2-12 - Performance of Emergency Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Cumulative Total MW
2002	551	$282,756	$513	1
2003	49	$26,613	$543	0
2004	0	$0	$0	0
2005	3,662	$1,859,638	$508	2

Economic Program

The Economic Program experienced a significant increase in MW enrolled in the program in 2004 and 2005, primarily associated with the integration of new areas into PJM. Data on the number of currently active sites in the Economic Program are presented in Table 2-13 along with the associated MW. As of November 30, 2005, there were 2,210.4 MW currently active in the Economic Program. This is a 34 percent increase from the 1,644.4 MW active in the Economic Program in the end of 2004 which was in turn an increase of 251 percent from the 468.7 MW active at the end of 2003.

Table 2-13 - Currently active participants in the Economic Program

	Currently Active by Year Enrolled		Cumulative Total	
	Sites	MW	Sites	MW
2001	NA	NA	NA	NA
2002	106	320.6	106	321.0
2003	142	147.7	248	468.7
2004	2,218	1,175.7	2,466	1,644.4
2005	124	566.0	2,590	2,210.4

36 In Table 2-12 and Table 2-15, the MMU includes only data that have been confirmed by PJM.

37 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.

Table 2-14 shows the zonal distribution of DSR capability in the Economic Program as of November 30, 2005. One zone includes 84 percent of total sites and 49 percent of total MW in the Economic Program. In addition, 85 percent of the sites and 67 percent of the MW in the Economic Program are located in the Western Region of PJM.

Table 2-14 - Current zonal capability in the Economic Program: Eleven months ended November 30, 2005

	Sites	MW
AECO	3	5.9
AEP	7	164.5
AP	16	195.1
BGE	147	120.8
ComEd	2,167	1074.5
DAY	0	0.0
DLCO	4	42.9
Dominion	3	77.5
DPL	25	127.8
JCPL	42	38.2
Met-Ed	15	44.8
PECO	73	72.8
PENELEC	9	81.8
PEPCO	29	35.4
PPL	14	85.0
PSEG	35	42.4
RECO	1	1.0
UGI	0	0.0
Total	2,590	2,210.4

The total MWh of load reductions and the associated payments under the Economic Program are shown in Table 2-15.[38] Load reduction levels in the Economic Program increased from 6,727 MWh in 2002 to 19,518 MWh in 2003 to 58,352 MWh in 2004 to 113,393 MWh in 2005. Payments per MWh were $106 in 2005. The Economic Program's actual MWh of load reduction per currently active MW increased to 51 for the 11-month period ending November 30, 2005.

Table 2-15 - Performance of PJM Economic Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Cumulative Total MW
2002	6,727	$801,119	$119	21
2003	19,518	$833,530	$43	42
2004	58,352	$1,917,202	$33	35
2005	113,393	$12,000,354	$106	51

38 Table 2-15 contains rounded numbers of "Total MWh" and "Total Payments."

During the 11 months ended November 30, 2005, the Economic Program showed significant differences in activity among the PJM control zones. For example, 58 percent of MWh reductions, 45 percent of payments and 27 percent of curtailed hours under the real-time rate option occurred within a single zone while one pricing zone saw no activity in any DSR program. (See Table 2-16.) The total number of curtailed hours for the Economic Program was about 113,393 and the total payment amount was $12,000,354.

Overall, approximately 66 percent of the MWh reductions, 51 percent of payments and 80 percent of curtailed hours resulted from customers with the real-time option under the Economic Program. Approximately 34 percent of the MWh reductions, 48 percent of payments and 19 percent of curtailed hours resulted from customers with the day-ahead option. Approximately 0.5 percent of the MWh reductions, 1 percent of the payments and 1 percent of the curtailed hours resulted from the dispatched-in-real-time option of the program. (See Table 2-16.)

A total of 26 retail customers registered as LMP-based customers,[39] of which seven were active load management (ALM) customers. In total, 68 customers selected the ALM option. PJM initiated ALM events twice in the summer 2005: July 27 and August 4. On July 27, ALM was invoked in the Mid-Atlantic Region and in the Dominion Control Zone. On August 4, ALM was invoked in the Mid-Atlantic Region.

During the Phase 2 integration of the ComEd Control Area, participants in ComEd load management initiatives were provided with an opportunity to take part in PJM's DSR programs. By November 30, 2005, 5,848 ComEd retail customers had enrolled in the program. Out of all registered ComEd participants, 2,167 selected the Economic Program and 3,681 selected the Emergency Program. Of the ComEd participants, 218 entered the program as ALM/mandatory interruptible load (MIL) customers.[40] None registered as LMP-based customers.

The maximum hourly load reduction attributable to the Economic Program was 226 MW in the 11-month period ended November 30, 2005. Using real-time supply curves, the price impact of this reduction in the Economic Program was estimated to be approximately $1 per MWh.[41] The total impact was approximately $124,000 during the hour of maximum hourly load reduction.

Based on real-time supply curves for a representative day during the summer of 2005 and the summer peak load, a reduction of 1,000 MW would have resulted in an approximate $4 per MW LMP decrease.

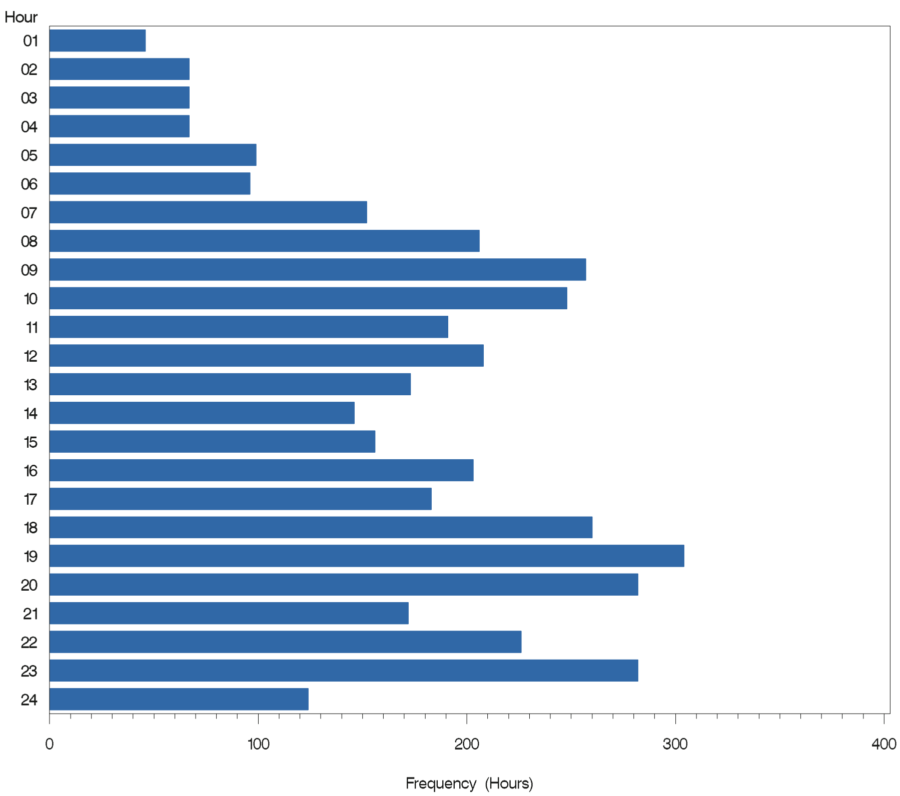
39 LMP-based customers are eligible to participate in the dispatched-in-real-time option of the program.
40 MIL is a month-by-month, year-round program for ComEd. For additional information, see Appendix H, "Glossary."
41 See Section 2, "Energy Market, Part 1," at Figure 2-1, "Average PJM aggregate supply curves: Summers 2004 and 2005."

Table 2-16 - PJM Economic Program by zonal reduction: Eleven months ended November 30, 2005

	Real time			Day ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	3,464.0	$300,855.08	813	0.0	$0.00	0	13.9	$3,214.75	18	3,477.8	$304,069.83	831
AEP	1,880.8	$104,605.75	227	0.0	$0.00	0	0.0	$0.00	0	1,880.8	$104,605.75	227
AP	43,357.3	$2,791,632.10	3,165	3,836.5	$823,131.70	303	315.7	$38,696.73	103	47,509.5	$3,653,460.53	3,571
BGE	7,419.7	$1,272,976.55	2,436	0.0	$0.00	0	0.0	$0.00	0	7,419.7	$1,272,976.55	2,436
ComEd	71.8	$4,052.16	183	(0.3)	$1,809.76	36	5.4	$467.14	29	76.9	$6,329.06	248
DLCO	2,718.9	$106,945.66	104	322.6	$55,878.95	14	182.5	$17,481.06	6	3,224.0	$180,305.67	124
Dominion	348.0	$35,451.81	22	0.0	$0.00	0	0.0	$0.00	0	348.0	$35,451.81	22
DPL	6,838.6	$868,445.42	1,747	32,789.3	$4,597,474.50	1,193	0.0	$0.00	0	39,627.9	$5,465,919.92	2,940
JCPL	44.8	$9,176.93	21	0.0	$0.00	0	0.0	$0.00	0	44.8	$9,176.93	21
Met-Ed	670.0	$36,819.76	720	0.0	$0.00	0	0.0	$0.00	0	670.0	$36,819.76	720
PECO	1,375.9	$224,882.91	1,105	0.0	$0.00	0	0.0	$0.00	0	1,375.9	$224,882.91	1,105
PENELEC	0.0	$0.00	0	0.0	$0.00	0	34.1	$3,695.43	29	34.1	$3,695.43	29
PPL	6,080.8	$362,615.53	504	261.7	$53,899.79	255	0.0	$0.00	0	6,342.5	$416,515.32	759
PSEG	416.4	$50,424.12	800	930.1	$233,274.64	1,005	11.1	$2,119.66	30	1,357.5	$285,818.42	1,835
RECO	3.3	$326.06	45	0.0	$0.00	0	0.0	$0.00	0	3.3	$326.06	45
UGI	0.0	$0.00	0	0.0	$0.00	0	0.0	$0.00	0	0.0	$0.00	0
Total	74,690.1	$6,169,209.84	11,892	38,140.0	$5,765,469.34	2,806	562.7	$65,674.77	215	113,392.7	$12,000,353.95	14,913
Max	43,357.3	$2,791,632.10	3,165	32,789.3	$4,597,474.50	1,193	315.7	$38,696.73	103	47,509.6	$5,465,919.92	3,571
Avg	4,668.1	$385,575.62	743	2,383.7	$360,341.83	175	35.2	$4,104.67	13	7,087.0	$750,022.12	932

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 33 percent of all MWh reductions, 9 percent of all payments and 28 percent of all curtailed hours under the Economic Program occurred when LMP was less than $75 per MWh. Figure 2-5 shows that reductions under the Economic Program when LMP was less than $75 per MWh were dispersed over all hours of the day, with maximum activity spread over hours ended 0800 EPT to 1000 EPT, 1200 EPT, 1600 EPT, 1800 EPT to 2000 EPT and 2200 EPT to 2300 EPT.

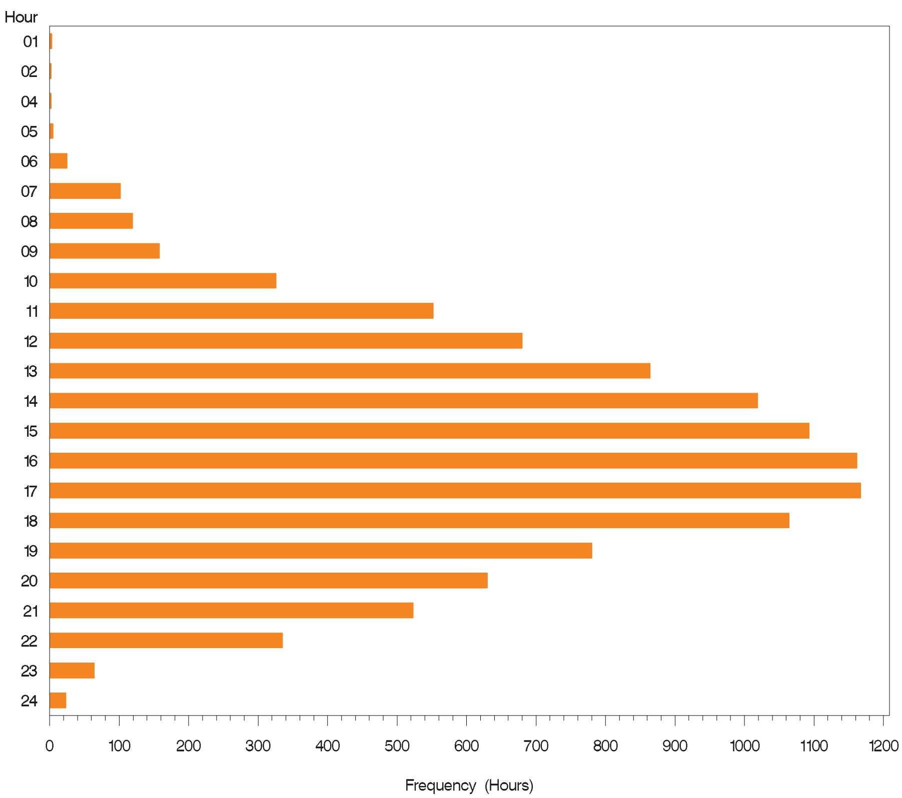
Figure 2-5 - Frequency distribution of Economic Program hours when LMP less than $75 per MWh (By hours): Eleven months ended November 30, 2005



Hour	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
01	46	46	1.09	1.09
02	67	113	1.59	2.68
03	67	180	1.59	4.27
04	67	247	1.59	5.86
05	99	346	2.35	8.21
06	96	442	2.28	10.49
07	152	594	3.61	14.09
08	206	800	4.89	18.98
09	257	1057	6.10	25.08
10	248	1305	5.88	30.96
11	191	1496	4.53	35.49
12	208	1704	4.93	40.43
13	173	1877	4.10	44.53
14	146	2023	3.46	48.00
15	156	2179	3.70	51.70
16	203	2382	4.82	56.51
17	183	2565	4.34	60.85
18	260	2825	6.17	67.02
19	304	3129	7.21	74.23
20	282	3411	6.69	80.93
21	172	3583	4.08	85.01
22	226	3809	5.36	90.37
23	282	4091	6.69	97.06
24	124	4215	2.94	100.00

Figure 2-6 shows that reductions under the Economic Program when LMP was equal to or greater than $75 per MWh were generally concentrated more narrowly in hours ended 1100 EPT to 2100 EPT, with maximum activity concentrated in hours ended 1400 EPT to 1800 EPT.

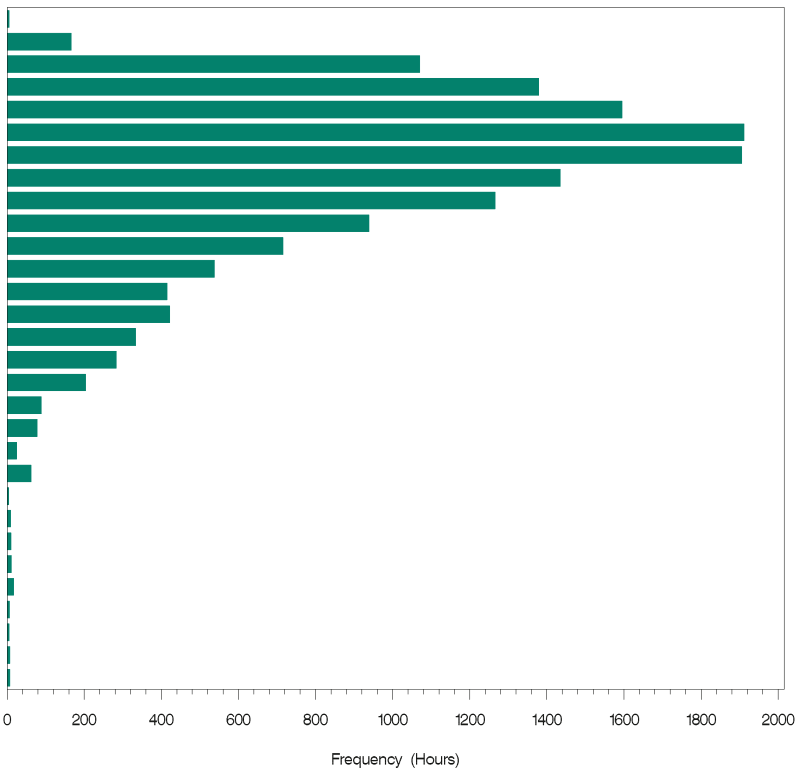
Figure 2-6 - Frequency distribution of Economic Program hours when LMP greater than or equal to $75 per MWh (By hours): Eleven months ended November 30, 2005



Hour	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
01	3	3	0.03	0.03
02	2	5	0.02	0.05
04	2	7	0.02	0.07
05	5	12	0.05	0.11
06	25	37	0.23	0.35
07	102	139	0.95	1.30
08	119	258	1.11	2.41
09	158	416	1.48	3.89
10	326	742	3.05	6.94
11	552	1294	5.16	12.10
12	680	1974	6.36	18.45
13	864	2838	8.08	26.53
14	1019	3857	9.53	36.05
15	1093	4950	10.22	46.27
16	1162	6112	10.86	57.13
17	1167	7279	10.91	68.04
18	1064	8343	9.95	77.99
19	780	9123	7.29	85.28
20	630	9753	5.89	91.17
21	523	10276	4.89	96.06
22	335	10611	3.13	99.19
23	64	10675	0.60	99.79
24	23	10698	0.21	100.00

Figure 2-7 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 $30 and $150 per MWh. A majority, 72 percent, of all hours in which reductions took place had an LMP greater than or equal to $75 per MWh.

Figure 2-7 - Frequency distribution of Economic Program LMP (By hours): Eleven months ended November 30, 2005



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$0 to $15	5	5	0.03	0.03
$15 to $30	166	171	1.11	1.15
$30 to $45	1070	1241	7.17	8.32
$45 to $60	1379	2620	9.25	17.57
$60 to $75	1595	4215	10.70	28.26
$75 to $90	1911	6126	12.81	41.08
$90 to $105	1906	8032	12.78	53.86
$105 to $120	1435	9467	9.62	63.48
$120 to $135	1266	10733	8.49	71.97
$135 to $150	939	11672	6.30	78.27
$150 to $165	716	12388	4.80	83.07
$165 to $180	538	12926	3.61	86.68
$180 to $195	415	13341	2.78	89.46
$195 to $210	422	13763	2.83	92.29
$210 to $225	333	14096	2.23	94.52
$225 to $240	283	14379	1.90	96.42
$240 to $255	204	14583	1.37	97.79
$255 to $270	89	14672	0.60	98.38
$270 to $285	78	14750	0.52	98.91
$285 to $300	25	14775	0.17	99.07
$300 to $315	62	14837	0.42	99.49
$315 to $330	4	14841	0.03	99.52
$330 to $345	9	14850	0.06	99.58
$345 to $360	10	14860	0.07	99.64
$360 to $375	11	14871	0.07	99.72
$375 to $390	17	14888	0.11	99.83
$390 to $405	6	14894	0.04	99.87
$405 to $420	5	14899	0.03	99.91
$450 to $465	7	14906	0.05	99.95
$480 to $495	7	14913	0.05	100.00

Nonhourly, Metered Program (Pilot Program)

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 the 11-month period ended November 30, 2005, there was no activity under the nonhourly, metered program.

Customer Demand-Side Response Programs

DSR Program Summary Data

In evaluating the level of DSR activity, it is important to include not just the activity that occurs in direct response to PJM programs, but also other types of DSR activity. Both state public utility commission policies on retail competition and the programs of individual LSEs have had a significant impact on DSR activity. It has been difficult to acquire meaningful data on these programs. To address this issue, PJM conducted surveys of LSEs in June 2003, June 2004 and June 2005 to obtain information about price-responsive tariffs as well as load-response programs offered at the retail level by either electric distribution companies or competitive electric suppliers.

The June 2005 PJM survey revealed that there is 3,653 MW of load in the PJM footprint that is exposed to a price signal that is a direct or indirect function of real-time prices, because of actions by state public utility commissions.

The survey results identified 1,216 MW of load that is exposed to real-time prices and an additional 2,437 MW of load that is partially exposed to real-time prices either directly or through an intermediary competitive supplier.[42] The prices paid by these retail customers are based on tariffs approved by state public utility commissions in New Jersey and Maryland or on supply contracts entered into with competitive LSEs. A total of 2,012 MW or 55 percent, take retail electric service under a rate that changes regularly to reflect current market prices. These prices change less frequently than hourly and more frequently than monthly. A total of 1,216 MW of load purchases electricity at a tariff rate tied directly to the hourly LMP. This load has chosen to pay LMP rates directly rather than to enter into a contract with a competitive supplier. The remaining 425 MW of the load pays prices determined by other contract provisions that link at least incremental usage decisions to hourly LMP prices.

The survey also identified a total of 907 MW enrolled in the programs administered by LSEs in the PJM territory. These programs provide incentives to reduce load during periods of high prices or system emergencies by means other than direct exposure to real-time LMP. Of the total, 289 MW or 32 percent was in direct load control programs under distribution LSEs that was not offered to PJM as ALM capability. Twenty-five percent or 224 MW is curtailable load. Twenty-three percent or 212 MW of load have a state approved regulated rate that provides incentives to curtail in response to market signals. Nineteen percent of the total was load that participated in the interruptible load programs of distribution LSEs and 2 percent was load subject to a distribution LSE's demand-response program and not offered to PJM as ALM capability.

The June 2005 PJM survey revealed that significant DSR activity has resulted from actions of state public utility commissions as they have implemented policies governing retail competition. The primary result has been that more load is exposed, at least partially, to real-time prices, either directly or via competitive supplier intermediaries. This is a critical prerequisite to an effective demand side of the wholesale energy markets. In addition, individual LSEs have implemented independent DSR programs that parallel PJM programs in basic design and that have resulted in additional DSR activity.

42 Load-Response Survey data were provided by PJM's Demand-Side Response department.

Summary data for demand-side response programs in PJM are presented in Table 2-17. The programs include the PJM Emergency Load-Response Program, the PJM Economic Load-Response Program, the PJM Active Load Management Program (net of ALM resources participating directly in other PJM demand-side programs) and additional programs reported by PJM customers in response to a survey.

Table 2-17 - Demand-side response programs: Eleven months ended November 30, 2005

PJM Programs	MW Registered
PJM Economic Load-Response Program (rounded value)	2,210
PJM Emergency Load-Response Program (rounded value)	1,619
PJM Active Load-Management Resources	2,065
PJM ALM Resources Included in Load-Response Program	(260)
Total PJM Programs	5,634
Additional Programs Reported By Customers in PJM Survey	
MW under DSR Programs Administered by LSEs in PJM Territory	
Competitive LSEs Reported Curtailable Load	224
Distribution LSEs Reported Direct Load Control Load not in ALM	289
Distribution LSEs Reported Other Demand Response not in ALM	14
Distribution LSEs Reported Other (Price Sensitive) Regulated Retail Rate Load	212
Distribution LSEs Reported Regulated Interruptible Load	168
Total MW under DSR Programs Administered by LSEs in PJM Territory	907
MW with Full and Partial Exposure to Real-Time LMP	
Competitive LSEs Reported Load - Partial Exposure to LMP	2,012
Competitive LSEs Reported Load - Other Contract Mechanism	425
Distribution LSEs Reported LMP Based Load	1,216
Total MW with Full and Partial Exposure to Real-Time LMP	3,653
Net Load, Including Survey Responses	10,194

Market Conduct

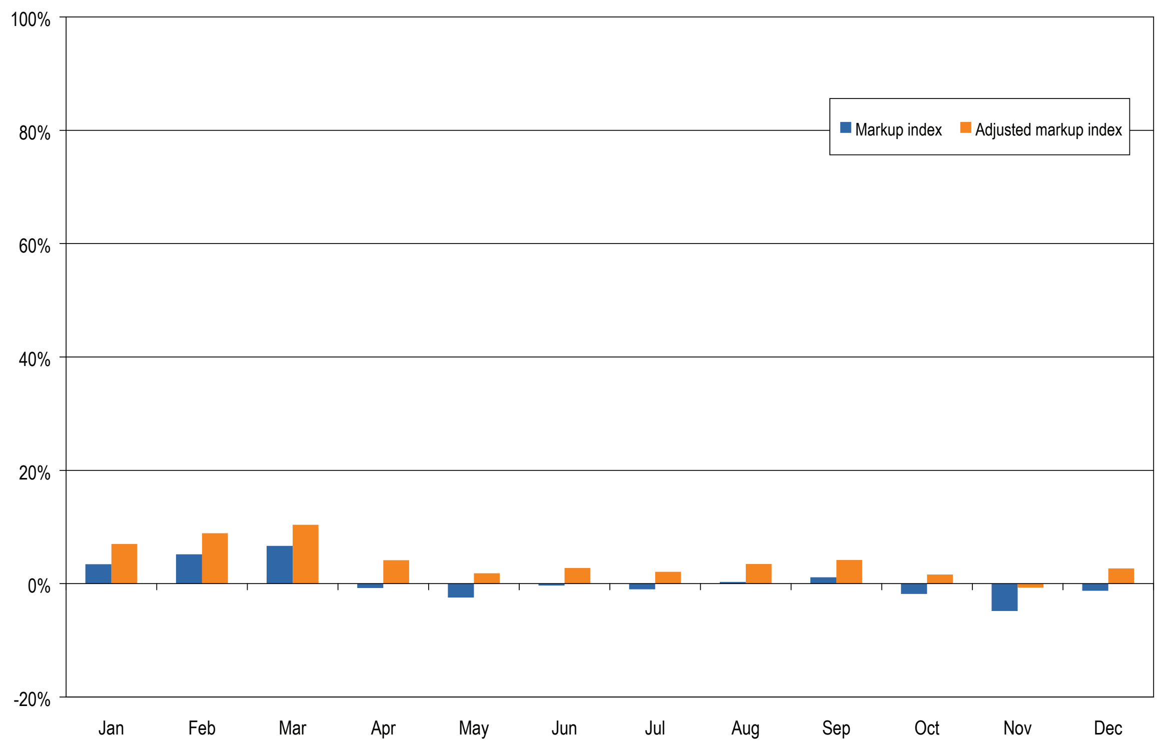
Price-Cost Markup Index

The price-cost markup index is a measure of market power. The goal of the markup analysis is to estimate the difference between the observed market price and the competitive market price.

The price-cost markup index is defined here as the difference between price (*P*) and marginal cost (*MC*), divided by price, where price and marginal cost are determined by the offers of the marginal unit [The markup index = (*P* – *MC*)/*P*]. The marginal unit is the unit that sets LMP in the five-minute interval. The markup of each marginal unit is load-weighted.[43] 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.[44] (See Figure 2-8.)

PJM receives daily price and cost offers for every unit in PJM which is not exempt from offer capping. For exempt units, cost offers are estimated. The markup index is calculated for the marginal unit or units in every five-minute interval.[45]

Figure 2-8 - Load-weighted, average monthly markup indices: Calendar year 2005



43 For example, if a marginal unit with a markup index of 0.50 set the LMP for 3,000 MW of load in an interval and a second marginal unit with a markup index of 0.01 set the LMP for 27,000 MW of load, the weighted-average markup index for the interval would be 0.06. Markup indices are load-weighted both within an individual five-minute interval and across intervals to determine monthly/annual averages.

44 The value of the index can be less than zero if a unit offers its output at less than marginal cost. This is not implausible because units in PJM may provide a cost curve equal to cost plus 10 percent. Thus the index can be negative if the marginal unit's offer price is between cost and cost plus 10 percent.

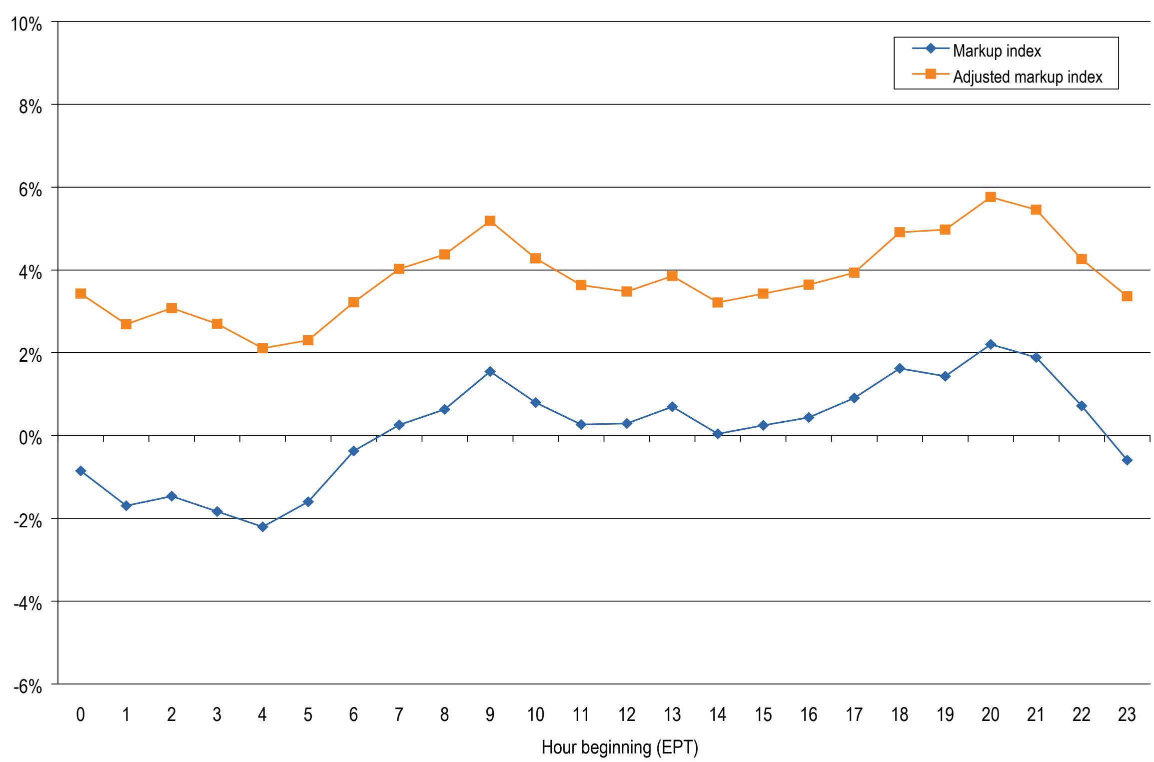
45 The markup indices incorporate several refinements including improvements to load weighting within and across hours.

Figure 2-8 shows the average monthly markup index. The load-weighted, average markup index was 0.3 percent in 2005, with a maximum of 6.7 percent in March and a minimum of -4.8 percent in November. Generators in PJM submit cost-based offers up to defined marginal cost plus 10 percent.[46] Since most, if not all, generators submit cost-based offers including this 10 percent, the calculated markup index may be low to the extent that the submitted offers are greater than actual marginal cost. The adjusted markup index in Figure 2-8 assumes that all unit owners have included a 10 percent markup over actual marginal cost and compares price to submitted cost less the 10 percent adder. This is an extreme assumption, but provides an upper bound to the actual markup index. Given this assumption, the load-weighted, average adjusted index for 2005 was 3.9 percent, with a maximum index of 10.4 percent in March and a minimum index of -0.7 percent in November. The correct markup index lies between the adjusted and unadjusted index values.

Actual markups for units exceed these average values at times and units with higher markups set the market price during some intervals. Similarly, actual markups for units are less than the average values at times and units with negative markups also set the price during some intervals. The load-weighted, average markup is a reasonable measure of the extent to which energy offers at levels in excess of marginal cost set the price in PJM. Observed markups in 2005 are lower than in 2004.

To illustrate the variation in markup levels in the Energy Market, the MMU analyzed the load-weighted, average markup index for each hour. Figure 2-9 shows the average markup by hour for the year. The figure shows that the markup tends to be higher during the peak hours of the day.

Figure 2-9 - Load-weighted, average hourly markup indices: Calendar year 2005



46 PJM Manual M-15, "Cost Development Guidelines," Revision 5 (August 18, 2005) provides the detailed definition of marginal cost that generation owners must follow when submitting cost-based offers. The 10 percent increment was designed to reflect the uncertainty associated with the calculation of marginal costs for the actual range of units in PJM and not to provide a mark up over cost.

The markup calculation is based on the marginal production cost of the marginal unit and could overstate the actual markup because it does not include the marginal cost of the next most expensive unit, an appropriate scarcity rent, if any, or an opportunity cost, if any. Thus, if the marginal unit is a CT with a price offer equal to $500 per MWh and the marginal cost of the unit is $130 per MWh, the observed price-cost markup index would be 0.74 [(500-130)/500]. If, however, the unit can export power and the real-time price in the external control area is $500 per MWh, then the appropriately calculated markup index would actually be zero.

To understand the dynamics underlying observed markups, the MMU analyzed marginal units in more detail, including by fuel type and plant type. Figure 2-10 shows the average, unit-specific markup by fuel type for marginal units. The unit markup index is calculated using price and marginal cost for the specific unit of the identified fuel type that is marginal during any five-minute interval. During 2005, unit markups ranged from -1.8 percent for coal-fired units to 10.1 percent for units burning petroleum.

Figure 2-10 - Average markup index of marginal units (By type of fuel): Calendar years 2001 to 2005

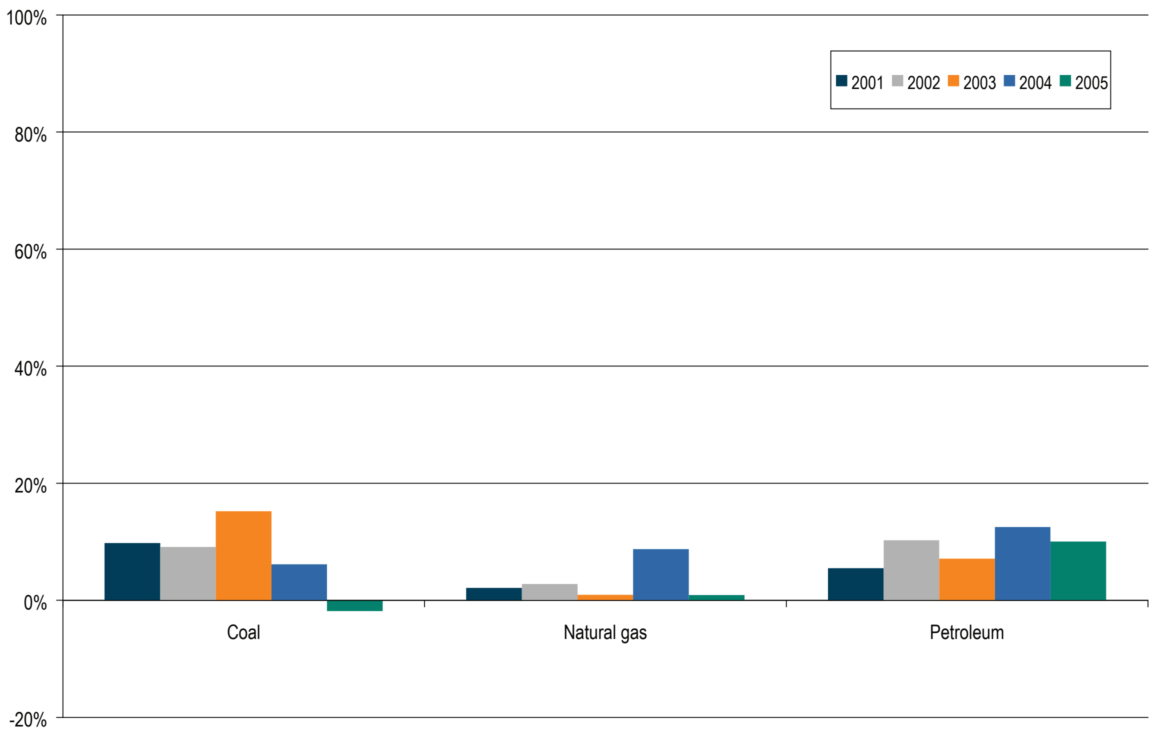


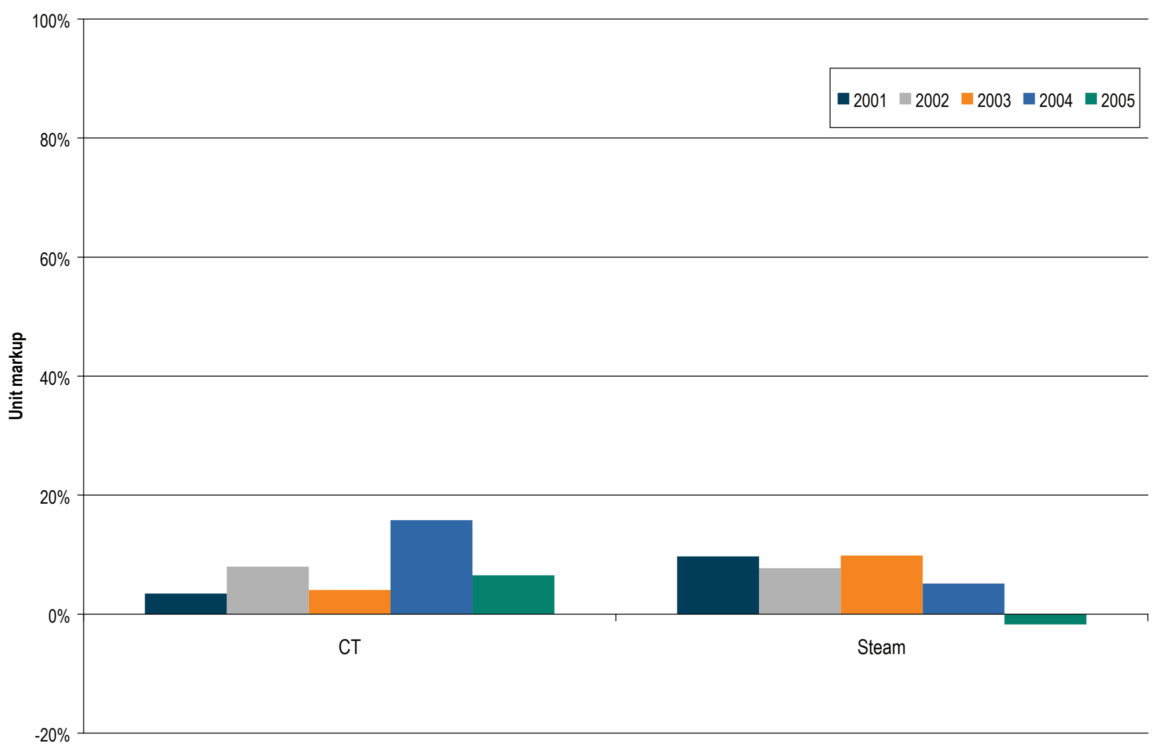
Table 2-18 shows the type of fuel used by marginal units.[47] Between 2004 and 2005, the share of coal rose from 56 percent to 62 percent; the share of natural gas decreased from 31 percent to 26 percent; the share of nuclear units held steady and the share of petroleum decreased from 12 percent to 11 percent.

Table 2-18 - Type of fuel used by marginal units: Calendar years 2001 to 2005[48]

Fuel Type	2001	2002	2003	2004	2005
Coal	49%	55%	52%	56%	62%
Misc	0%	0%	0%	0%	0%
Natural Gas	18%	23%	29%	31%	26%
Nuclear	1%	0%	1%	0%	0%
Petroleum	32%	21%	18%	12%	11%

Figure 2-11 shows the average markup index of marginal units by unit type. The markup levels reflect lower overall markups in 2005, with the average annual markup for CTs decreasing to 6.5 percent from 16 percent in 2004 and for steam units decreasing to -1.7 percent from 5 percent in 2004.

Figure 2-11 - Average markup index of marginal unit (By unit type): Calendar years 2001 to 2005



47 These percentages represent the number of times units of the specified fuel appeared on the margin versus the number of units on the margin overall. No weighting is done with respect to time or load share.

48 The primary fuels contained in the miscellaneous category include methane, petroleum coke, refuse, refinery gas, waste coal, wood and wood waste.

Table 2-19 shows the type of units on the margin from 2001 to 2005. During 2005, the marginal unit was a CT for 23 percent of the time and a steam unit for 77 percent of the time.

Table 2-19 - Type of marginal unit: Calendar years 2001 to 2005[49]

Unit Type	2001	2002	2003	2004	2005
CT	33%	26%	22%	22%	23%
Steam	67%	74%	77%	77%	77%

Overall, the markup results presented here are consistent with the conclusion that the Energy Market results were competitive in 2005.

Offer Capping

PJM has clear rules limiting the exercise of local market power.[50] 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-capped units receive the higher of the market price or their offer cap. Thus, if overall market conditions lead to a price greater than the offer cap, the unit receives the overall 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 do not permit the offer capping of exempt units. Such exempt units can and do exercise market power, at times, that would not be permitted if the units were not exempt.

During 2005, two FERC orders modified the rules governing exemptions from the offer-capping rules.

In the January 25 order, the Commission addressed the offer-capping exemption for units whose construction had commenced on or after July 9, 1996. The Commission 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."[51] The Commission 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."[52] The FERC stated: "The exemption will not apply to any unit in any PJM zone for which construction commenced after PJM submitted its proposal to remove the post-1996 exemption on September 30, 2003."[53]

In the July 5 order, the Commission modified the dates governing unit exemptions by zone.[54] These orders reduced the number of units potentially exempt from local market power mitigation from 215 to 56 as of the end of 2005.

49 Percentages for CTs include diesel units.
50 See "PJM Operating Agreement, Schedule 1," Section 6.4.2.
51 110 FERC ¶ 61,053 (2005).
52 110 FERC ¶ 61,053 (2005).
53 110 FERC ¶ 61,053 (2005).
54 112 FERC ¶ 61,031 (2005).

Despite regulatory changes, levels of offer capping have generally been quite stable over the past few years, as shown in Table 2-20.

Table 2-20 - Annual offer-capping statistics: Calendar years 2001 to 2005

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2001	2.8%	1.0%	2.8%	0.7%
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%

Table 2-21 through Table 2-24 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 Markets.

Table 2-21 - Average day-ahead, offer-capped units: Calendar years 2001 to 2005

	2001		2002		2003		2004		2005	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.5	0.1%	0.6	0.1%	0.5	0.1%	0.4	0.1%	0.4	0.0%
Feb	3.2	0.7%	0.4	0.1%	0.7	0.1%	0.2	0.0%	0.4	0.0%
Mar	6.8	1.5%	0.1	0.0%	0.1	0.0%	0.2	0.0%	0.6	0.1%
Apr	3.4	0.8%	0.7	0.1%	0.6	0.1%	0.3	0.1%	0.4	0.0%
May	2.8	0.6%	0.2	0.0%	0.3	0.0%	0.6	0.1%	0.2	0.0%
Jun	4.7	1.0%	1.4	0.3%	0.7	0.1%	1.1	0.2%	0.4	0.0%
Jul	3.8	0.8%	1.9	0.4%	1.4	0.3%	2.6	0.4%	0.9	0.1%
Aug	1.9	0.4%	4.5	0.8%	2.1	0.4%	3.0	0.4%	1.1	0.1%
Sep	5.0	1.1%	1.9	0.4%	1.1	0.2%	3.1	0.4%	0.2	0.0%
Oct	4.2	0.9%	0.4	0.1%	0.9	0.2%	0.6	0.1%	0.3	0.0%
Nov	2.1	0.5%	0.6	0.1%	0.2	0.0%	0.5	0.1%	0.2	0.0%
Dec	0.4	0.1%	0.8	0.1%	0.1	0.0%	0.5	0.1%	0.7	0.1%

Table 2-22 - Average day-ahead, offer-capped MW: Calendar years 2001 to 2005

	2001		2002		2003		2004		2005	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	32	0.1%	40	0.1%	37	0.1%	51	0.1%	87	0.1%
Feb	16	0.0%	30	0.1%	27	0.1%	68	0.1%	75	0.1%
Mar	101	0.3%	6	0.0%	4	0.0%	48	0.1%	58	0.1%
Apr	286	1.0%	48	0.1%	38	0.1%	41	0.1%	34	0.0%
May	286	1.0%	14	0.0%	52	0.1%	52	0.1%	14	0.0%
Jun	591	1.7%	48	0.1%	69	0.2%	49	0.1%	28	0.4%
Jul	203	0.6%	77	0.1%	132	0.3%	243	0.4%	52	0.0%
Aug	91	0.2%	106	0.2%	148	0.3%	348	0.5%	63	0.1%
Sep	332	1.0%	78	0.2%	139	0.3%	221	0.4%	13	0.0%
Oct	193	0.6%	57	0.1%	100	0.2%	34	0.0%	16	0.0%
Nov	192	0.6%	30	0.1%	21	0.1%	28	0.0%	26	0.0%
Dec	18	0.1%	25	0.1%	25	0.1%	35	0.0%	48	0.0%

Table 2-23 - Average real-time, offer-capped units: Calendar years 2001 to 2005

	2001		2002		2003		2004		2005	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.7	0.2%	1.6	0.3%	1.5	0.3%	2.7	0.4%	2.5	0.3%
Feb	0.5	0.1%	0.8	0.2%	1.5	0.3%	0.7	0.1%	1.3	0.1%
Mar	3.4	0.8%	0.4	0.1%	0.5	0.1%	0.8	0.1%	1.4	0.2%
Apr	3.3	0.8%	1.0	0.2%	0.8	0.1%	1.9	0.3%	1.2	0.1%
May	3.5	0.8%	1.2	0.2%	1.6	0.3%	5.9	0.8%	0.8	0.1%
Jun	6.5	1.5%	3.1	0.6%	2.9	0.5%	3.9	0.5%	10.0	1.0%
Jul	4.8	1.1%	8.6	1.6%	3.3	0.6%	4.7	0.7%	13.9	1.4%
Aug	8.1	1.8%	9.7	1.8%	6.3	1.1%	6.3	0.9%	13.7	1.4%
Sep	7.3	1.6%	4.1	0.8%	3.7	0.7%	4.2	0.6%	7.9	0.8%
Oct	6.9	1.5%	1.4	0.3%	1.8	0.3%	1.1	0.1%	7.9	0.8%
Nov	4.5	1.0%	1.2	0.2%	1.0	0.2%	1.1	0.1%	3.3	0.3%
Dec	1.3	0.3%	1.5	0.3%	0.8	0.1%	3.3	0.4%	4.4	0.4%

Table 2-24 - Average real-time, offer-capped MW: Calendar years 2001 to 2005

	2001		2002		2003		2004		2005	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	46	0.1%	90	0.3%	87	0.2%	175	0.4%	209	0.3%
Feb	7	0.0%	46	0.2%	74	0.2%	87	0.2%	145	0.2%
Mar	84	0.3%	24	0.1%	44	0.1%	76	0.2%	74	0.1%
Apr	248	0.9%	62	0.2%	29	0.1%	115	0.3%	59	0.1%
May	291	1.1%	63	0.2%	101	0.3%	257	0.5%	78	0.1%
Jun	455	1.4%	105	0.3%	110	0.3%	167	0.3%	652	0.7%
Jul	247	0.8%	218	0.6%	252	0.6%	332	0.6%	819	0.9%
Aug	372	1.0%	311	0.7%	294	0.7%	450	0.8%	908	1.0%
Sep	553	1.9%	177	0.5%	241	0.7%	268	0.5%	477	0.6%
Oct	571	2.1%	92	0.3%	96	0.3%	77	0.1%	337	0.5%
Nov	410	1.5%	55	0.2%	53	0.2%	110	0.2%	129	0.2%
Dec	90	0.3%	52	0.1%	44	0.1%	202	0.3%	156	0.2%

Table 2-25 through Table 2-29 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.[55] For example, in 2001 three units were offer-capped for more than 80 percent of their run hours and had at least 300 offer-capped run hours. The count of units in each category includes units that also met more restrictive criteria. In this example, the three units that were offer-capped more than 80 percent of their run hours and had a total of at least 300 run hours are also included in the 200 offer-capped run hour column as well as the 100 offer-capped run hour column and the one offer-capped run hour column. Similarly in this example, the three units that were offer-capped more than 80 percent of their run hours are also included in each of the following rows as they were also offer-capped more than 75 percent, 60 percent, 50 percent, 25 percent and 10 percent of their run hours. 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.

Table 2-25 - Offer-capped unit statistics: Calendar year 2001

Percentage of Offer-Capped Run Hours	2001 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	0	0	2	2	2	2
80%	0	0	3	3	6	8
75%	0	0	4	4	9	13
60%	0	0	4	5	11	22
50%	1	1	5	6	12	30
25%	13	15	19	20	28	72
10%	18	20	24	27	38	117

55 Data quality improvements have caused values in these tables to vary slightly from previously published results.

Table 2-26 - 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 2-27 - 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 2-28 - 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 2-29 - 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

Table 2-29 shows an increase in the number of units in most categories from 2004. This can be attributed to the expansion of the PJM footprint which increased the number of units, as 2005 was the first full calendar year reflecting the impact of the 2004 integrations in addition to the phased 2005 integrations of the DLCO and Dominion Control Zones. In addition, the 2005 results reflect for the first time the inclusion of 55 units that were offer-capped when running for reactive voltage support at nuclear power plants as well as the decrease in the number of units exempt from mitigation, noted above. Table 2-20 shows that real-time offer-capping levels did not increase in 2005 as a proportion of MW although they did increase slightly as a proportion of unit hours, suggesting offer capping of smaller units, and a slight decrease in day-ahead offer capping both as a proportion of MW and of unit hours.

Structural Definition of Local Market Power

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.

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 lift offer capping when the exercise of market power is unlikely based on the application of a market structure screen.

PJM's three pivotal supplier test represents the practical application of the FERC's market power tests in real time. 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 of less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

Through its January 25 order, the Commission instituted a section 206 inquiry to determine whether the three pivotal supplier test needed to be revised.[56] In its July 5 order, the Commission consolidated its January 25 section 206 inquiry with a second section 206 inquiry regarding PJM's proposal to conduct competitive analyses for major interfaces and issues related to scarcity pricing in PJM.[57]

On November 16, 2005, PJM filed a settlement agreement among the parties to the proceeding (the Settlement Agreement).[58] The agreement, approved by the FERC in January 2006, resolved all issues set for hearing in the consolidated proceeding.[59]

Frequently Mitigated Units

Table 2-30 - Aggregate offer-capping statistics for FMUs: Calendar year 2005

Real-Time Percent Hours Capped	80%
Real-Time Percent MW Capped	85%
Day-Ahead Percent Hours Capped	81%
Day-Ahead Percent MW Capped	74%

Early in 2005, the FERC ordered that frequently offer-capped units be provided additional compensation as a form of scarcity pricing. An FMU was defined to be a unit that was offer-capped more than 80 percent of its run hours over the prior 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.

The Settlement Agreement provided for an expansion of the definition of FMUs to include units offer-capped for 60 percent of their run hours and for a set of graduated adders associated with varying levels of offer capping. In addition, the Settlement provided for the designation of associated units (AU). This designation applies to a unit that is electrically identical to an FMU, but did not reach the target threshold. For instance, 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 an FMU. If the second unit were capped for 30 percent of its run hours, this unit would be an associated unit and receive the same adder as the FMU at the site.

There were a total of 40 units that met the FMU criteria in 2005 along with one AU for a total of 41 units. All the units were CTs that were located in the Phase 1 PJM footprint and are on the eastern side of the Central Interface. The designated units were permitted to include the $40 adder in their offer caps as of April 1, 2005. Table 2-30 shows summary statistics for FMUs for 2005.

56 110 FERC ¶ 61,053 (2005).
57 112 FERC ¶ 61,031 (2005).
58 *PJM Interconnection, L.L.C.,* Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
59 114 FERC ¶ 61,076 (2006).

Market Performance: Load and LMP

Energy Market Prices

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.[60]

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

The PJM system load and LMP reflect the configuration of the entire regional transmission organization (RTO). Thus, during Phases 4 and 5 of calendar year 2005, load and LMP reflect the integration of new PJM control zones as they occurred.

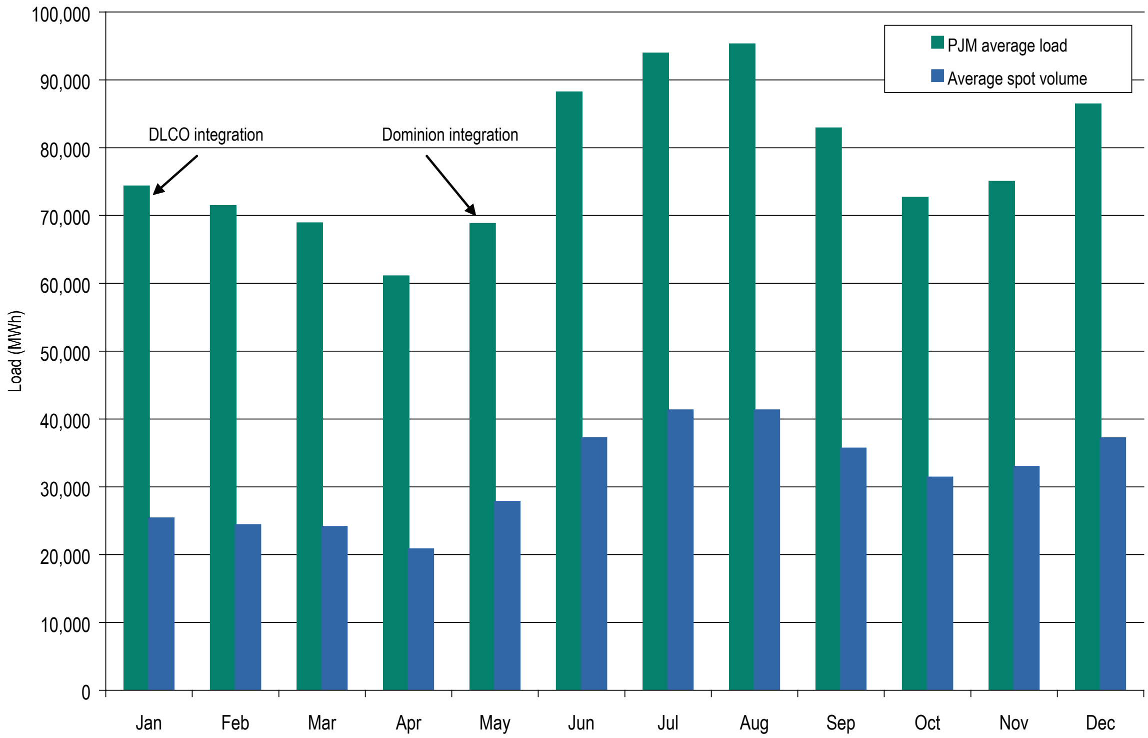
Spot Market Load and Spot Market Volume

In 2005, Real-Time Energy Market activity averaged 35,333 MW during on-peak periods, 28,226 MW during off-peak periods and 31,536 MW averaged over all hours. This represented 40.5 percent of on-peak load, 40.2 percent of off-peak load and 40.4 percent of all hours' real-time load. (See Figure 2-12.) In 2005, Day-Ahead Energy Market activity averaged 32,727 MW on peak, 25,289 MW off peak, or 28,831 MW averaged over all hours. This represented 31.9 percent of on-peak load, 30.6 percent of off-peak load and 31.3 percent of all hours' day-ahead load. 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 alternatives to such Spot Market transactions are self-supply and bilateral arrangements. The fact that transactions occur in the Real-Time and Day-Ahead Energy Markets does not necessarily mean that participants are exposed to the related short-term prices. Longer term bilateral contracts can and do clear through the PJM Energy Markets. A significant proportion of the Spot Market activity represents such underlying bilateral contracts.

Total Real-Time Energy Market activity increased by 79.6 percent on peak and 81.3 percent off peak over 2004 levels. Total real-time load also grew in 2005 and Spot Market activity as a proportion of load in the Real-Time Energy Market increased from 35 percent in 2004 to 40 percent in 2005. Total Day-Ahead Energy Market activity increased by 85.8 percent on peak and 81.2 percent off peak over 2004 levels. Total day-ahead load also grew in 2005 and Spot Market activity as a proportion of load in the Day-Ahead Energy Market increased from 26 percent in 2004 to 31 percent in 2005.

60 See Appendix C, "Energy Market," for methodological background, detailed price data and comparisons.

Figure 2-12 - PJM average hourly load and Spot Market volume: Calendar year 2005



Real-Time Energy Market Prices

PJM Real-Time Energy Market prices increased in 2005. The simple hourly average system LMP for 2005 was 37.0 percent higher than the 2004 annual average, $58.08 per MWh versus $42.40 per MWh.[61] The simple average LMP for 2005 was higher than in all previous years since the introduction of markets in PJM. When hourly load levels are reflected, the hourly load-weighted LMP for 2005 was 43.1 percent higher than it had been for the 2004 annual average, $63.46 per MWh versus $44.34 per MWh. In 2005, the highest load levels occurred during the summer while in 2004 the highest load levels occurred in the last quarter as a result of the integrations of ComEd, AEP and DAY when LMP was relatively low.

When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP in 2005 was 1.5 percent higher than the load-weighted LMP in 2004, $45.02 per MWh compared to $44.34 per MWh. If fuel prices for the year 2005 had been the same as for 2004, the 2005 load-weighted LMP would have been $45.02 per MWh instead of $63.46 per MWh. This means that, if it had not been for fuel cost increases, LMP would have been only 1.5 percent higher in 2005 than in 2004.

Real-time PJM system LMP in 2005 was consistently greater than it had been during 2004 from June through the end of the year. Several factors affect LMP, including fuel prices and load. All fuel prices were higher in 2005 than in 2004. Natural gas prices were 45.6 percent higher. No. 2 (light) oil prices were 41.5 percent higher and No. 6 (heavy) oil prices were 45.6 percent higher in 2005. In addition to higher fuel costs,

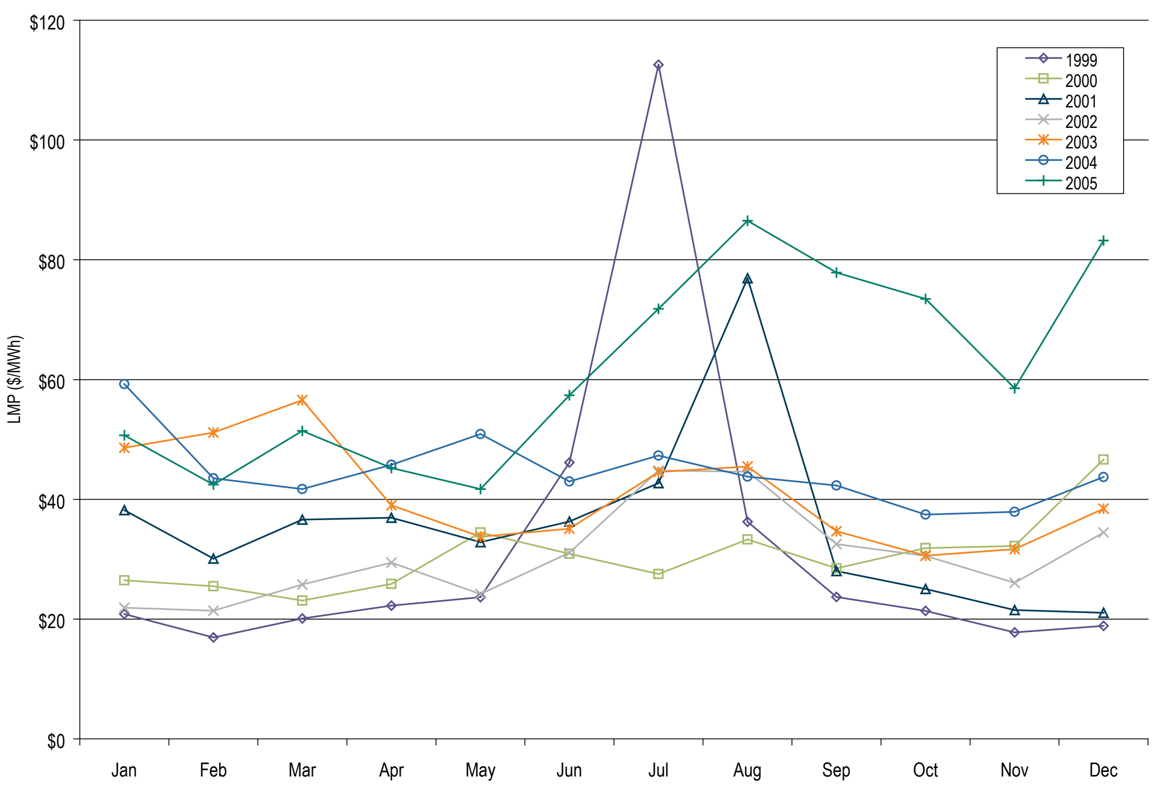
61 The simple average system LMP is the average of the hourly LMP in each hour without any weighting.

PJM load was higher in 2005 than it was in 2004 both as a result of integrations and as a result of warmer weather. Throughout the PJM footprint, the temperature-humidity index (THI) values for 2005 were higher than the THI values for 2004 indicating that the summer of 2005 was hotter than the summer of 2004.

Two principal factors contribute to higher overall LMP for 2005:

- **Fuel Prices.** Higher natural gas, oil and coal prices were a significant source of upward pressure on LMP in 2005. Figure 2-13 shows the PJM system monthly load-weighted LMP from 1999 through 2005. Figure 2-14 and Figure 2-15 show average, daily delivered coal, natural gas and oil prices for units within PJM.[62] Natural gas prices were 45.6 percent higher during 2005 as compared to 2004 with the largest differences starting in July and continuing throughout the rest of the year. No. 2 oil prices averaged 41.5 percent higher in 2005 and No. 6 oil averaged 45.6 percent higher in 2005. Higher fuel costs affect LMP when units burning those fuels are on the margin and thus setting price.[63]

Figure 2-13 - Monthly load-weighted, average LMP: Calendar years 1999 through 2005



62 Natural gas prices are the average of the daily cash price for Transco-Z6 (non-New York), Transco-Z5, Chicago Citygates and Texas Eastern-M3 and are 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 average price for 1.2 and 1.5 pound sulfur content per MBtu Central Appalachian coal for prompt rail delivery and for 0.8 pound sulfur content per MBtu Powder River Basin coal for prompt rail delivery and are adjusted for transportation. All fuel prices are from Platts except for the 2004 coal data which are from Energy Argus.

63 See Table 2-18 "Type of fuels used by marginal units: Calendar years 2001 to 2005."

Figure 2-14 - Spot coal and natural gas price comparison: Calendar years 2004 through 2005

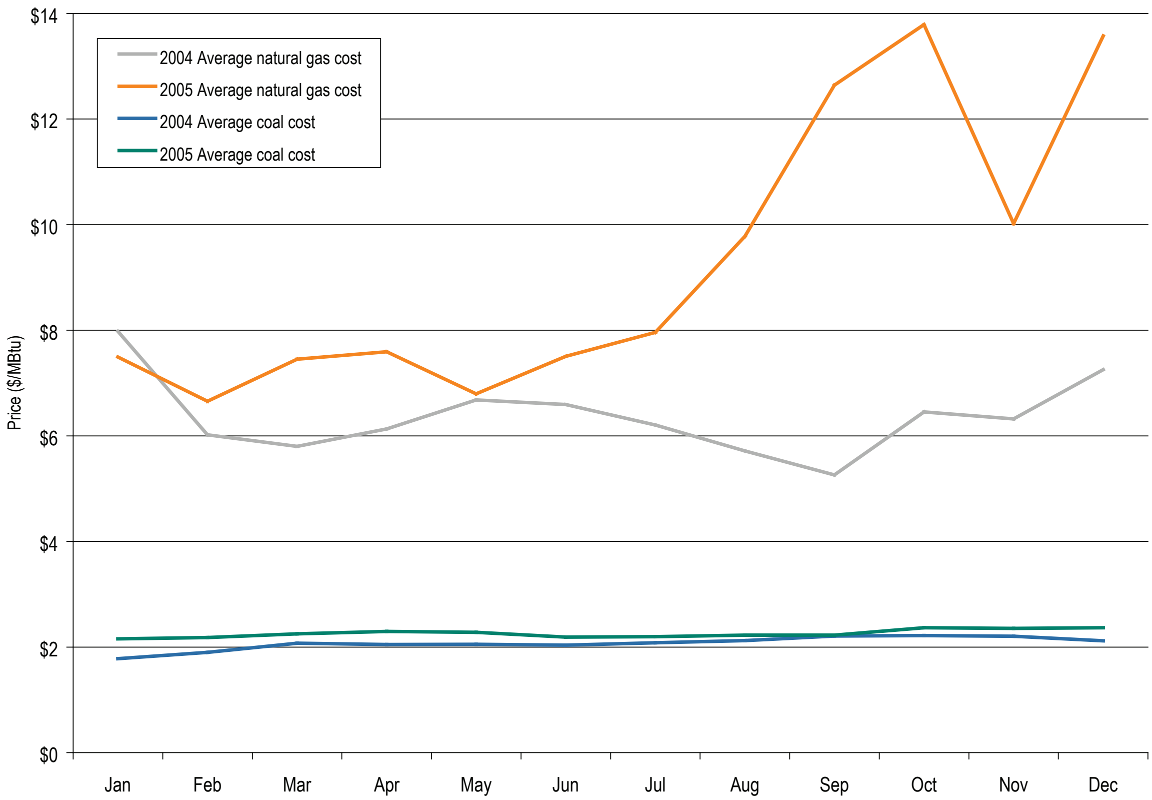
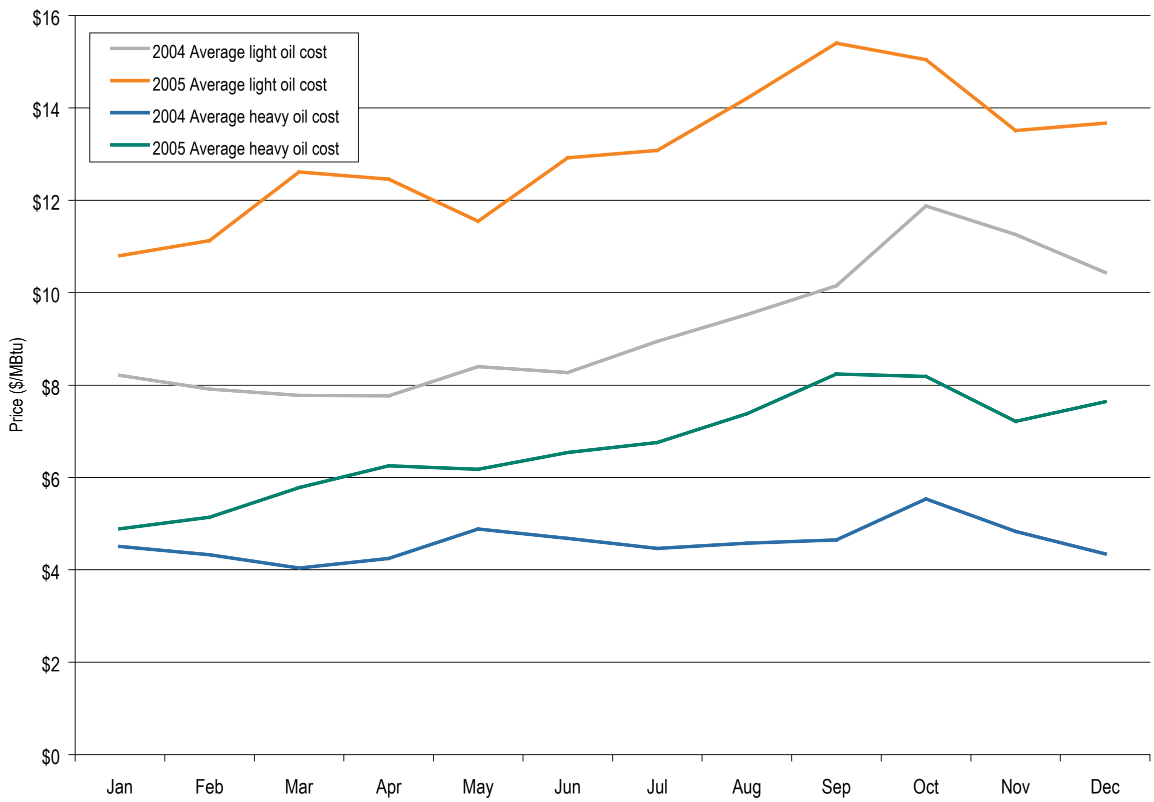


Figure 2-15 - Spot oil price comparison: Calendar years 2004 through 2005



- **Demand.** On average, PJM load increased in 2005 by 56.4 percent over the 2004 annual load primarily because of integrations and higher weather-related summer loads in 2005. Figure 2-16 shows the monthly average loads for 2004 and 2005 with and without the integrations. Figure 2-16 indicates that the 2005 PJM annual load, even without the integrations, was greater than it had been in 2004 by about 18.8 percent.

Figure 2-16 - PJM average load: Calendar years 2004 through 2005

THI is a measure of effective temperature using temperature and relative humidity. There is a correlation between THI and PJM summer load. Table 2-31 shows the monthly average of the daily maximum THI values of four representative sites within the PJM footprint: Philadelphia, Pennsylvania; Chicago, Illinois; Columbus, Ohio; and Richmond, Virginia.[64] THI is defined as follows:

temperature - .55*(1-relative humidity/100)*(temperature – 58).[65]

64 Temperature and relative humidity data that were used to calculate THI for Philadelphia, Chicago, Columbus and Richmond were obtained from Meteorlogix. See Appendix H, "Glossary," for more detail.

65 See PJM, "Load Data Systems Manual," Section M19, Section 3, pp. 11-16.

As Table 2-31 shows, the monthly averages of the daily maximum THI values for June, July and August within the PJM footprint were higher in 2005 than in 2004. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 3.20 percent, 2.56 percent and 4.06 percent, respectively.

Table 2-31 - Monthly average of daily maximum THI for four representative sites

	2004	2005	Difference
May	72.12	65.58	(9.07%)
Jun	73.69	76.05	3.20%
Jul	76.54	78.50	2.56%
Aug	74.69	77.72	4.06%
Sep	72.84	74.18	1.84%

Average Hourly, Unweighted System LMP

At $58.08 per MWh, the average hourly, unweighted system LMP for 2005 was 37.0 percent higher than the annual LMP for 2004. (See Table 2-32.)[66]

Table 2-32 - PJM average hourly LMP (Dollars per MWh): Calendar years 1998 through 2005

	Locational Marginal Prices (LMPs)			Year-to-Year Changes		
	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%

Price Duration

For 2005, PJM system prices exceeded $150 per MWh for 234 hours, and exceeded $200 per MWh for 35 hours with the maximum LMP of $286.86 per MWh occurring on July 27 during the hour ending 1400 EPT.[67]

Prices reflect the interaction of demand (in the form of energy bids) and supply (in the form of energy offers). The additional capacity provided by the 2004 integrations of the ComEd, AEP and DAY Control Zones as well as by the 2005 integrations of the DLCO and Dominion Control Zones, shifted the aggregate supply curve to the right. As a result of the fact that increases in aggregate supply exceeded increases in aggregate

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

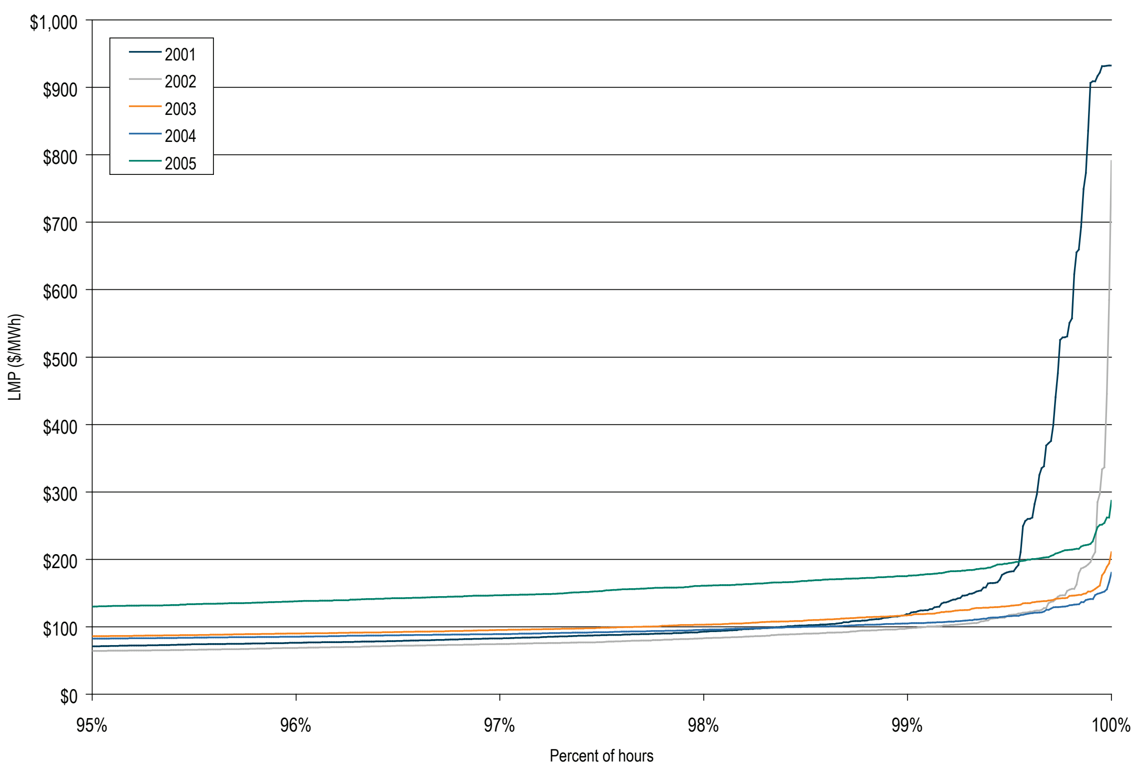
67 See Appendix C, "Energy Market," and Figure C-8.

demand, there were no hours when aggregate scarcity existed in 2005, although there were two days that exhibited regional scarcity.[68]

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-17 presents price duration curves for hours above the 95th percentile from 2001 to 2005. Figure 2-17 shows that since 2001, prices have generally exceeded $100 per MWh for less than 2 percent of the hours. In the year 2001, prices exceeded $100 per MWh for 1.6 percent of the hours, in 2002 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 and in 2005 for 12.6 percent of the hours. As Figure 2-17 shows, LMPs have been less than $100 per MWh during 95 percent or more of the hours, for every year except 2005.

Figure 2-17 shows that LMP exceeded $900 per MWh in 2001. In 2001, prices rose to more than $900 per MWh for 10 hours during the week of August 6. Prices in 2002 exceeded $700 per MWh for only one hour, but exceeded $150 per MWh for 20 hours. Prices in 2003 exceeded $200 per MWh for only one hour, but exceeded $150 per MWh for a total of 11 hours. Prices in 2004 exceeded $150 per MWh for only five hours and exceeded $120 per MWh for a total of 35 hours. Prices in 2005 exceeded $150 per MWh for 234 hours and exceeded $200 per MWh for a total of 35 hours.

Figure 2-17 - Price duration curves for the PJM Real-Time Energy Market during hours above the 95th Percentile: Calendar years 2001 through 2005



68 For additional information, see “Scarcity” in Section 3, “Energy Market, Part 2.”

Load

Table 2-33 presents summary load statistics for the eight-year period 1998 to 2005. The average load of 78,150 MWh in 2005 was 56.4 percent higher than in the 2004 annual average, reflecting the integrations of the DLCO and Dominion Control Zones and the impact of warmer summer weather.

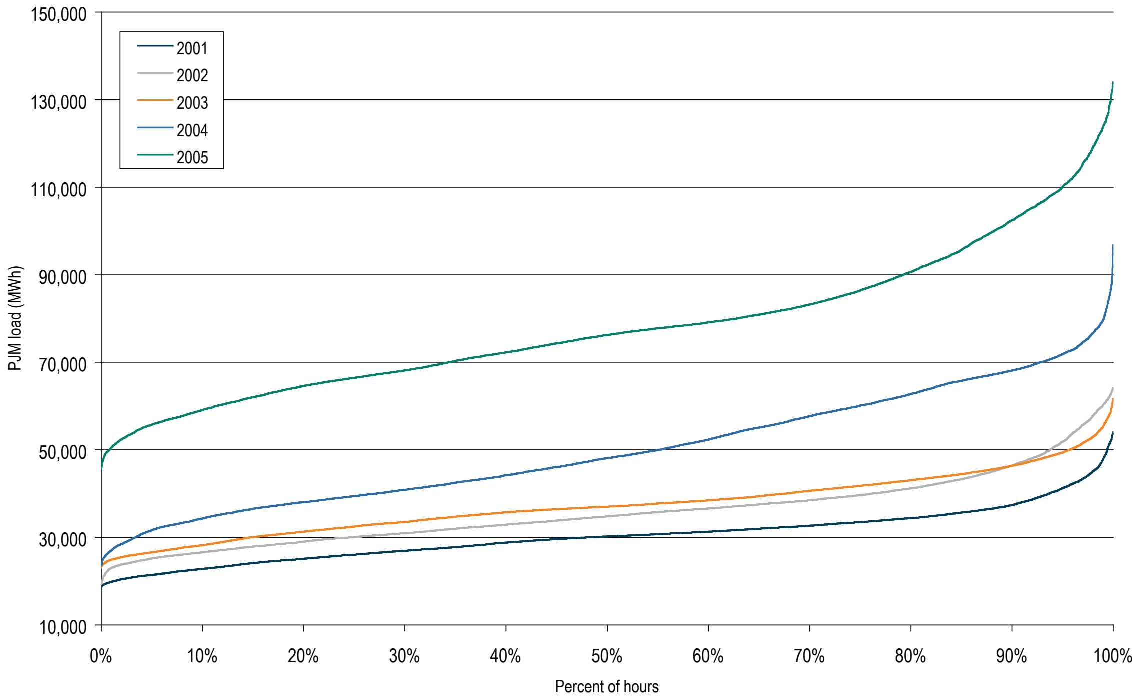
Table 2-33 - PJM average load: Calendar years 1998 through 2005

	PJM Load (MWh)			Year-to-Year Changes		
	Average	Median	Standard Deviation	Average Load	Median Load	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%

Load Duration

Figure 2-18 shows load duration curves from 2001 through 2005. A load duration curve shows the percent of hours that load was at, or below, a given level for the year. The 2005 load duration curve reflects the integrations of the DLCO and Dominion Control Zones as well as the impact of warmer summer weather.

Figure 2-18 - PJM hourly load duration curves: Calendar years 2001 through 2005



Load-Weighted LMP

Market participants typically purchase more energy during high-priced periods because higher demand 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. When hourly prices are weighted by hourly load levels, the increase from calendar year 2004 compared to 2005 in the hourly load-weighted, average LMP was 43.1 percent while the simple average LMP increased by 37.0 percent.

As Table 2-34 shows, 2005 load-weighted LMP rose to $63.46 per MWh, 43.1 percent higher than it had been in 2004, 53.9 percent higher than in 2003 and 100.9 percent higher than in 2002.[69]

Table 2-34 - PJM load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through 2005

	Load-Weighted, Average LMP			Year-to-Year Changes		
	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%

Fuel Cost and Price

Changes in LMP can result from changes in unit costs. The impact of fuel costs on LMP depends on the fuel burned by marginal units, the units setting LMP. Fuel costs make up between 80 percent and 90 percent of marginal costs depending on generating technology. To account for the changes in fuel cost between 2004 and 2005, the 2005 load-weighted LMP was adjusted to reflect the changes in the price of fuels used by marginal units and the change in the amount of load affected by the price of the marginal unit.

Spot prices were used for the gas and oil fuel prices and emission costs for NO_x and SO_2 for each fuel type were calculated based on unit-specific emission rates and the spot prices for NO_x and SO_2 emission credits. The emissions costs for NO_x are applicable for the May through September ozone season and the emissions costs for SO_2 are applicable throughout the year. Coal prices were calculated based on unit-specific information and also include the costs of NO_x and SO_2 emission credit costs.

Table 2-35 compares the 2005 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2004 load-weighted, average LMP. The fuel-cost-adjusted, load-weighted, average LMP for 2005 was 1.5 percent higher than load-weighed, average LMP for 2004.

Table 2-35 - PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2004	2005	Change
Average	$44.34	$45.02	1.5%
Median	$40.16	$38.75	(3.5%)
Standard Deviation	$21.25	$25.68	20.8%

69 See Appendix C, "Energy Market," for on-peak and off-peak, load-weighted LMP details.

Day-Ahead Energy Market LMP

When the PJM Day-Ahead Energy Market was introduced on June 1, 2000, it was expected that competition would cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Price convergence does not necessarily mean a zero or even a very small difference in price as there may be factors, from operating reserve charges to risk that result in a competitive, market-based differential. As Table 2-36, Figure 2-19 and Figure 2-21 show, day-ahead and real-time prices have converged. PJM average day-ahead prices were lower than real-time prices by $0.19 per MWh during 2005. The relationship between day-ahead and real-time prices changes from hour to hour and from year to year. In 2004, the day-ahead prices were lower than real-time prices by $0.97 per MWh. On average, day-ahead prices were higher than real-time prices by $0.45 per MWh in 2003, by $0.12 per MWh in 2002, by $0.37 per MWh in 2001 and by $1.61 per MWh in 2000.

In 2005 during Phase 4, day-ahead prices in PJM were $0.52 per MWh lower than real-time prices. During Phase 5, day-ahead prices in PJM were $0.02 per MWh lower than real-time prices. By contrast, in the DLCO Control Zone during Phase 4, day-ahead prices were greater than real-time prices by $0.03 per MWh. During Phase 5, the DLCO Control Zone day-ahead prices were greater than real-time prices by $2.25 per MWh. In the Dominion Control Zone during Phase 5, day-ahead prices were less than real-time prices by $1.97 per MWh.

Figure 2-19 shows the 2005 day-ahead and real-time price duration curves. The day-ahead prices were higher than real-time prices for 71 percent of the hours.

Figure 2-19 - PJM price duration curves for the Day-Ahead and Real-Time Energy Markets: Calendar year 2005

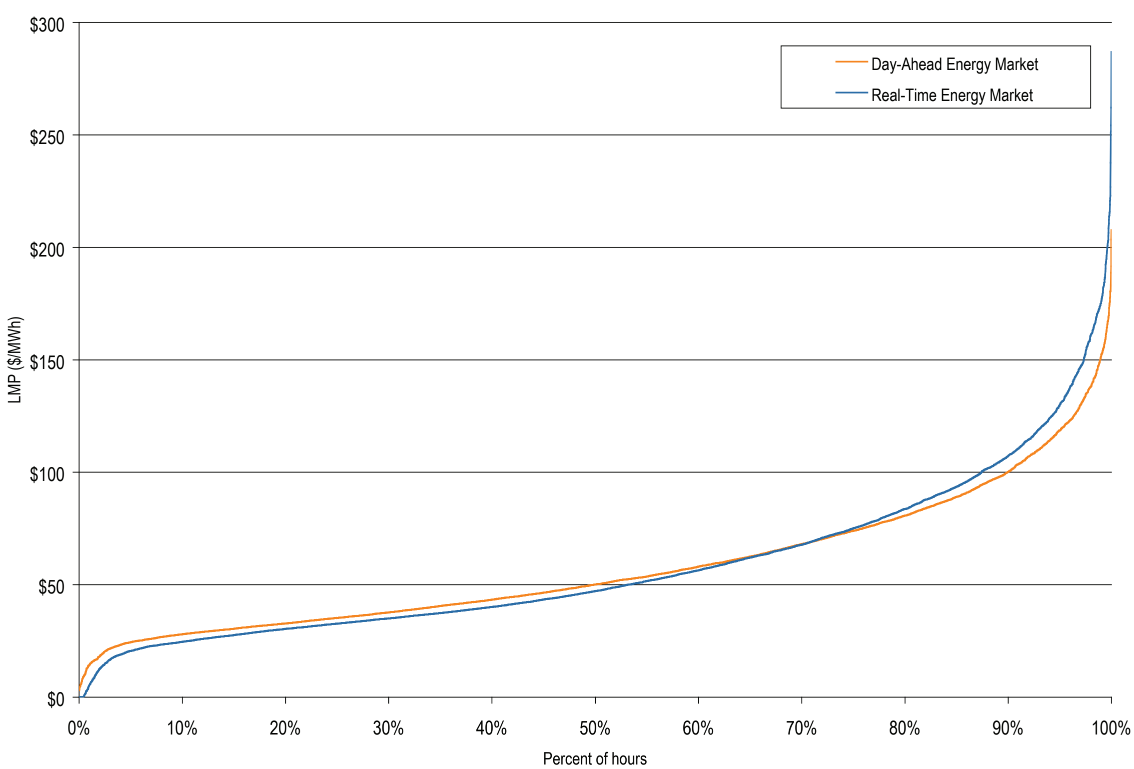


Figure 2-20 shows the hourly differences between day-ahead and real-time LMP in 2005. Although the average difference between the Day-Ahead and Real-Time Energy Markets was $0.19 per MWh for the entire year, Figure 2-20 shows considerable variation, both positive and negative, between day-ahead and real-time prices.

Figure 2-20 - Hourly real-time minus day-ahead average LMP: Calendar year 2005

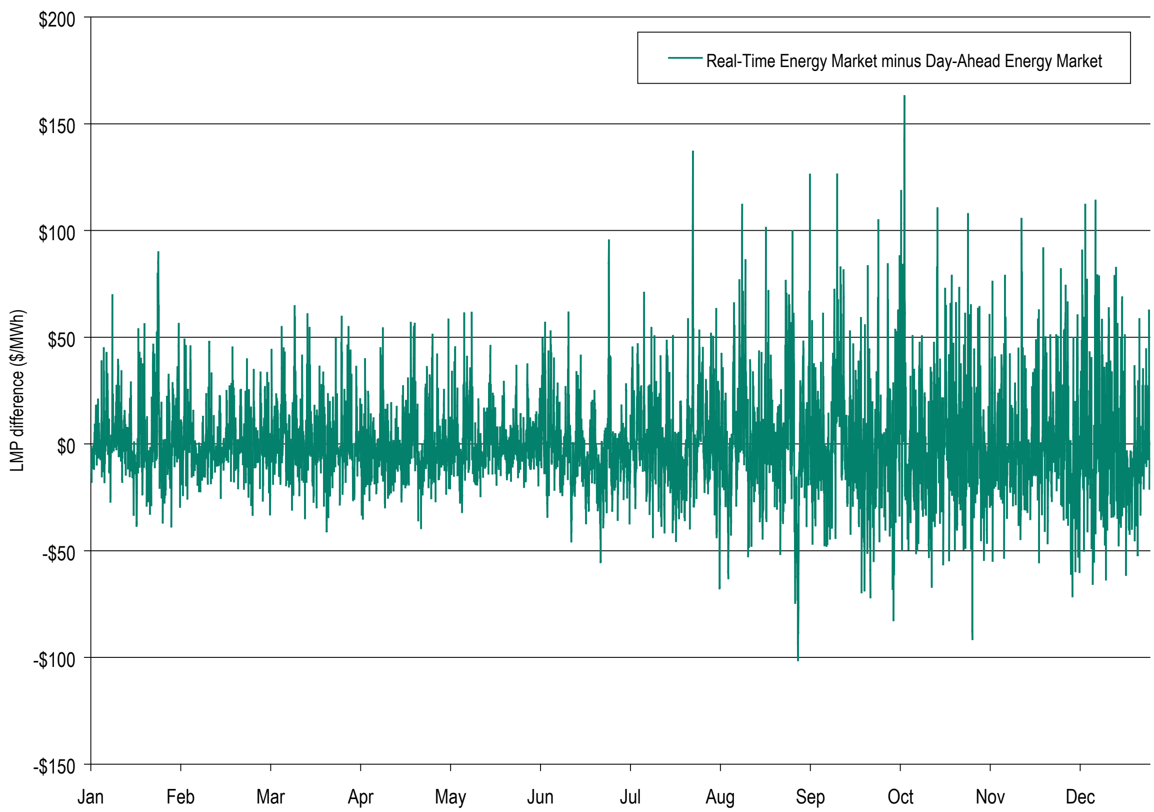
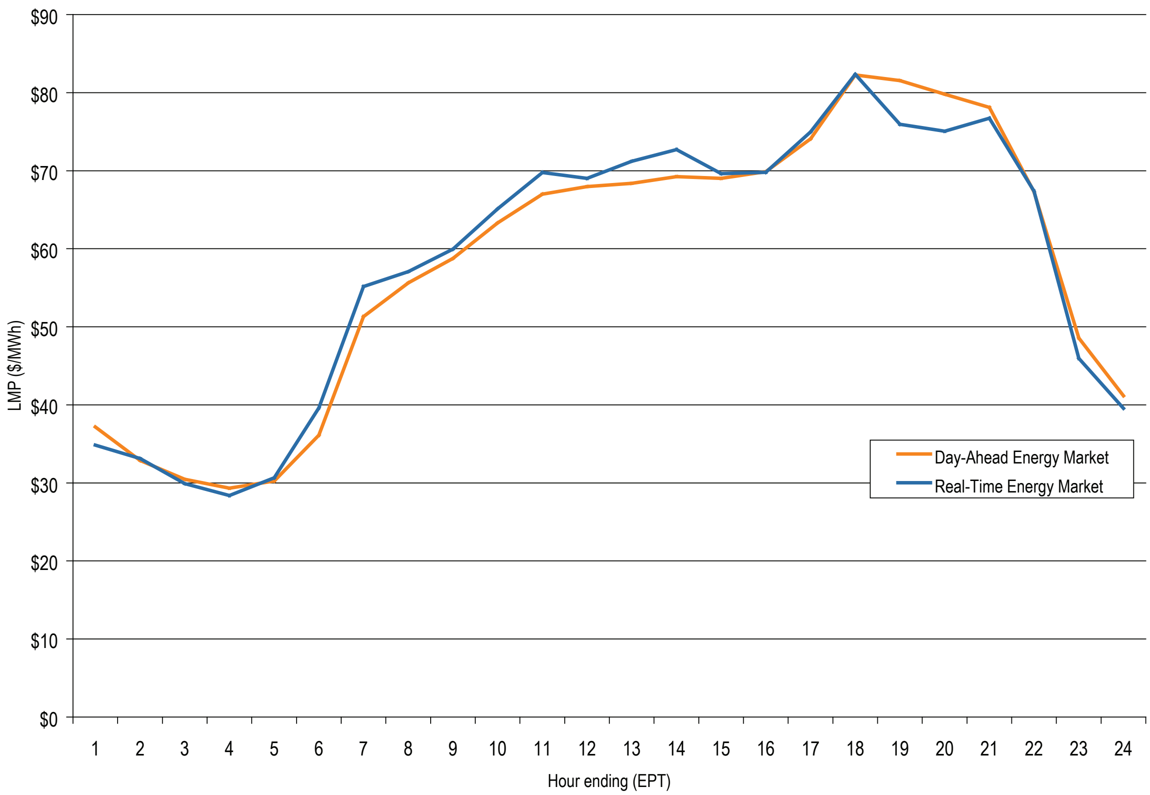


Figure 2-21 shows that average day-ahead and real-time LMPs were very close on an hourly basis, but that average real-time LMP was greater than average day-ahead LMP for 15 out of 24 hours.[70]

Figure 2-21 - PJM hourly system average LMP: Calendar year 2005



70 See Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Table 2-36 presents summary statistics for the PJM Energy Market. During 2005, average LMP in the Real-Time Energy Market was $0.19 per MWh or 0.3 percent higher than average LMP in the Day-Ahead Energy Market. The real-time median LMP was 6.1 percent lower than day-ahead median LMP, reflecting an average difference of $2.90 per MWh. Consistent with the price duration curve, price dispersion in the Real-Time Energy Market was 16.3 percent greater than in the Day-Ahead Energy Market, with an average difference in standard deviation between the two of $5.87 per MWh.

Table 2-36 - Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2005

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$57.89	$58.08	$0.19	0.3%
Median	$50.08	$47.18	($2.90)	(6.1%)
Standard Deviation	$30.04	$35.91	$5.87	16.3%

Zonal LMP

Table 2-37 shows PJM's 2004 and 2005 zonal real-time average LMPs. The largest zonal increase was in the ComEd Control Zone which experienced a 56.4 percent increase over 2004 and the smallest increase was in the JCPL Control Zone which experienced a 33.9 percent increase over 2004.

Table 2-37 - Zonal Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2004 and 2005

	2004	2005	Difference	Difference as Percent
AECO	$47.93	$68.17	$20.24	42.2%
AEP	$33.12	$47.36	$14.24	43.0%
AP	$41.16	$58.21	$17.05	41.4%
BGE	$44.27	$67.92	$23.65	53.4%
ComEd	$29.74	$46.50	$16.76	56.4%
DAY	$32.74	$45.95	$13.21	40.3%
DLCO	NA	$43.67	NA	NA
Dominion	NA	$73.27	NA	NA
DPL	$45.79	$65.64	$19.85	43.4%
JCPL	$49.03	$65.65	$16.62	33.9%
Met-Ed	$43.81	$64.24	$20.43	46.6%
PECO	$44.98	$65.44	$20.46	45.5%
PENELEC	$41.21	$56.55	$15.34	37.2%
PEPCO	$44.68	$69.10	$24.42	54.7%
PPL	$42.80	$63.05	$20.25	47.3%
PSEG	$49.54	$69.82	$20.28	40.9%
RECO	$46.87	$67.61	$20.74	44.3%

Table 2-38 shows the 2005 zonal day-ahead and real-time average LMPs. The difference between zonal day-ahead and real-time LMP ranged from 3.5 percent in the DLCO Control Zone, where the average day-ahead LMP was higher than the average real-time LMP, to -2.6 percent in the Dominion Control Zone, where the average day-ahead LMP was lower than the average real-time LMP.

Table 2-38 - Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2005

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$68.95	$68.17	$0.78	1.1%
AEP	$47.99	$47.36	$0.63	1.3%
AP	$58.14	$58.21	($0.07)	(0.1%)
BGE	$66.88	$67.92	($1.04)	(1.5%)
ComEd	$46.94	$46.50	$0.44	0.9%
DAY	$46.83	$45.95	$0.88	1.9%
DLCO	$45.19	$43.67	$1.52	3.5%
Dominion	$71.39	$73.27	($1.88)	(2.6%)
DPL	$67.06	$65.64	$1.42	2.2%
JCPL	$65.78	$65.65	$0.13	0.2%
Met-Ed	$64.90	$64.24	$0.66	1.0%
PECO	$66.78	$65.44	$1.34	2.0%
PENELEC	$56.74	$56.55	$0.19	0.3%
PEPCO	$68.24	$69.10	($0.86)	(1.2%)
PPL	$64.14	$63.05	$1.09	1.7%
PSEG	$68.56	$69.82	($1.26)	(1.8%)
RECO	$66.30	$67.61	($1.31)	(1.9%)

Day-Ahead and Real-Time Generation

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

In the Day-Ahead Energy Market,[71] 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.[72]

- **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.

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

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

Figure 2-22 shows average hourly values of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2005. Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. During 2005, real-time generation was always higher than day-ahead generation. If, however, increment offers were added to day-ahead generation, total day-ahead MW offers always exceeded real-time generation.

Figure 2-22 - Day-ahead and real-time generation (Average hourly values): Calendar year 2005

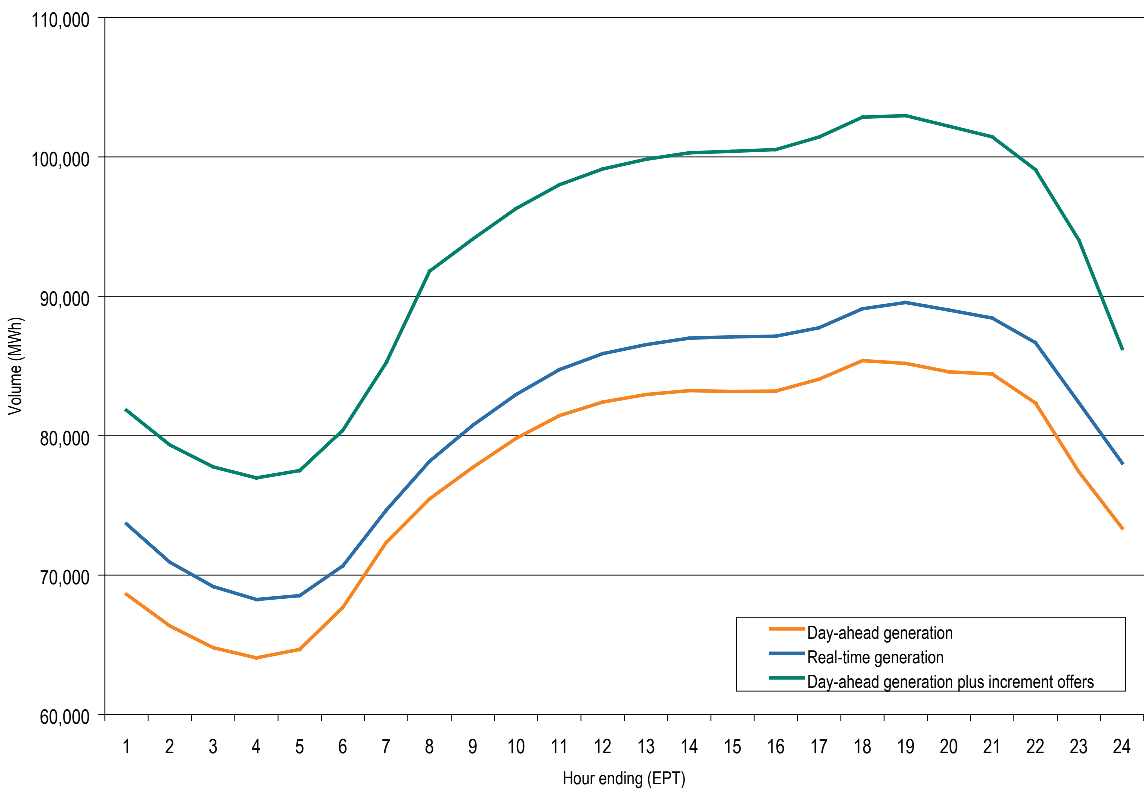


Table 2-39 presents summary statistics for 2005 day-ahead and real-time generation and the average differences between them. Day-ahead generation averaged 3,849 MWh less than real-time generation. Day-ahead generation offers plus cleared increment (INC) offers were 11,779 MWh higher than real-time generation, on average.

Table 2-39 - Day-ahead and real-time generation (MWh):[73] Calendar year 2005

	Day Ahead			Real Time	Average Difference	
	Generation	Cleared INC Offers	Generation Plus Cleared INC Offers	Generation	Generation	Generation Plus Cleared INC Offers
Average	77,278	15,628	92,906	81,127	(3,849)	11,779
Median	75,830	14,955	91,321	79,043	(3,213)	12,278
Standard Deviation	14,176	3,591	16,932	15,452	(1,276)	1,480

Day-Ahead and Real-Time 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 bids are made:

- **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.

73 Cleared INC offers represent the offers placed at the zone and not the offers at individual buses or aggregates within the zone.

Figure 2-23 shows the average 2005 hourly values of total day-ahead load, total fixed-demand bids, total price-sensitive bids, total decrement bids and total real-time load (total day-ahead load is the sum of the three types of demand bids).

Figure 2-23 - Day-ahead and real-time loads (Average hourly values): Calendar year 2005

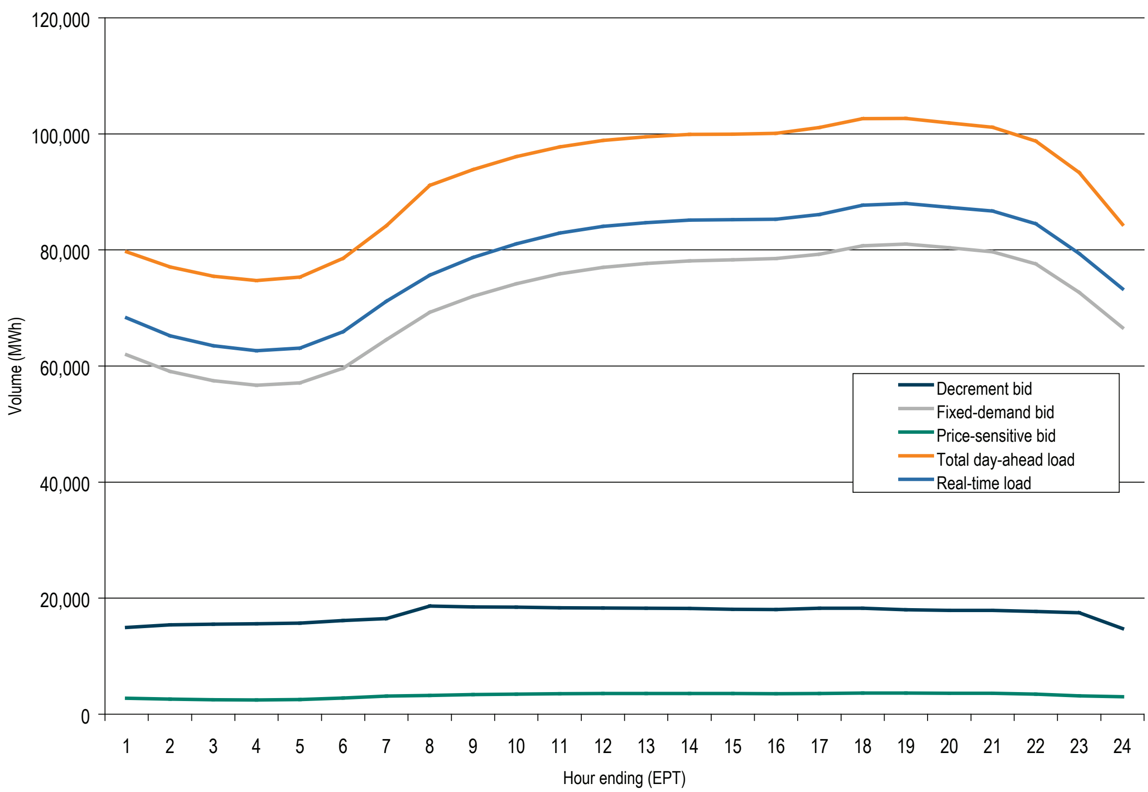


Table 2-40 presents 2005 summary statistics for day-ahead load components, total day-ahead load, real-time load and the difference between total day-ahead load and total real-time load.

Figure 2-23 and Table 2-40 show that, during 2005, total day-ahead load was higher than real-time load by an average of 13,852 MWh. The table also indicates that, at 77.7 percent, fixed demand was the largest component of day-ahead load. At 3.5 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 18.8 percent of day-ahead load.

Table 2-40 - Cleared day-ahead and real-time load (MWh): Calendar year 2005

	Day Ahead				Real Time	
	Fixed Demand	Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Difference
Average	71,469	3,246	17,287	92,002	78,150	13,852
Median	69,531	3,248	17,093	90,424	76,247	14,177
Standard Deviation	15,226	750	2,479	17,382	16,296	1,086

As Figure 2-23 shows, day-ahead load components increased during on-peak hours (i.e., hours ending 0800 EPT to 2300 EPT) as did real-time load. Table 2-41 shows average load MWh values in the Day-Ahead and Real-Time Energy Markets for 2005 during off-peak and on-peak hours. During 2005, real-time load was always higher than fixed-demand load plus price-sensitive load in the Day-Ahead Energy Market. If, however, decrement bids are included, then the day-ahead load always exceeded real-time load, and total day-ahead load was higher than real-time load during both off-peak and on-peak hours.

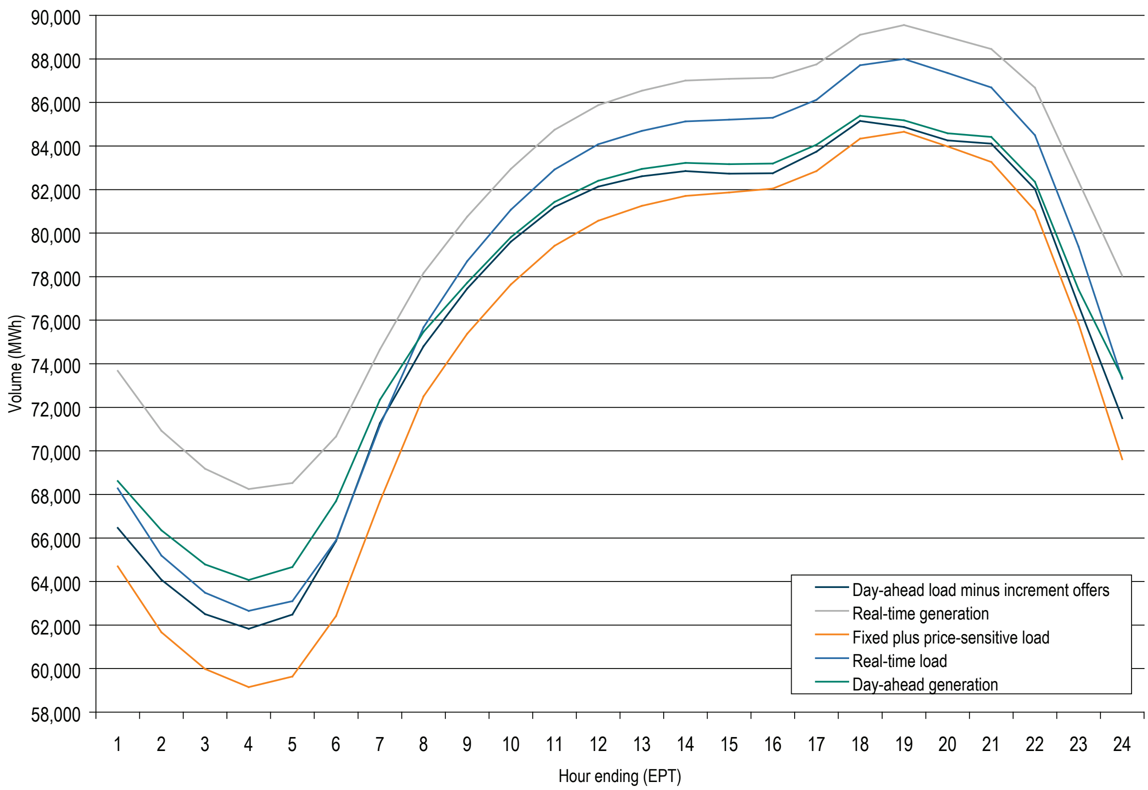
Referring to Table 2-41, the average difference during off-peak hours was 12,446 MWh, while the average difference during on-peak hours was 15,466 MWh. The percentage of day-ahead load represented by each of the components was generally different during off-peak as compared to during on-peak periods. Fixed demand accounted for the largest percentage of day-ahead load at approximately 77 percent and 78 percent during the off-peak and on-peak periods, respectively. Price-sensitive load accounted for the smallest percentage of day-ahead load at approximately 4 percent during both the off-peak and on-peak periods. Cleared decrement bids accounted for 19 percent and 18 percent for the off-peak and on-peak periods, respectively.

Table 2-41 - Cleared day-ahead and real-time loads during off-peak and on-peak hours (MWh): Calendar year 2005

	Day Ahead								Real Time	
	Off Peak				On Peak				Off Peak	On Peak
	Fixed Demand	Price Sensitive	Cleared DEC Bid	Total Load	Fixed Demand	Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load
Average	63,971	2,903	15,863	82,737	80,070	3,639	18,921	102,630	70,291	87,164
Median	62,138	2,885	15,887	81,212	75,520	3,606	18,651	97,721	68,049	82,503
Standard Deviation	11,551	689	1,724	12,654	14,363	610	2,188	15,926	12,733	15,236

Figure 2-24 shows day-ahead and real-time load and generation for 2005. For this analysis, increment offers were subtracted from total day-ahead load. The total day-ahead load is the sum of the fixed-demand bids, price-sensitive bids and the decrement bids. The subtraction of increment offers from day-ahead load equals the day-ahead generation that would have had to be turned on to meet the load.

Figure 2-24 - Day-ahead and real-time load and generation (Average hourly values): Calendar year 2005



SECTION 3 – ENERGY MARKET, PART 2

The PJM Market Monitoring Unit (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.

During the last two calendar years, PJM has 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. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[1]

- **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,[2] and the Allegheny Power Company (AP) Control Zone.[3]

- **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).[4]

- **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* for more detailed descriptions of Phases 1, 2 and 3.

2 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

3 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 the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

4 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).

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 PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. 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 2005 net revenue indicates that the fixed costs of new peaking and midmerit units were not fully covered, but that the fixed costs of new coal-fired baseload were covered. During the seven-year period 1999 to 2005, 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 prices and lower Capacity Market prices.

Existing and Planned Generation

- **PJM Installed Capacity**. During the period January 1 through December 31, 2005, PJM installed capacity grew by approximately 20,100 MW, primarily as a result of the integration of new areas into the PJM markets.

- **PJM Installed Capacity by Fuel Type.** At the end of 2005, PJM installed capacity was about 163,471 MW. Of the total installed capacity, 41.5 percent was coal, 27.5 percent was natural gas, 19.1 percent was nuclear, 7.2 percent was oil, 4.3 percent was hydroelectric and 0.3 percent was solid waste.

- **Generation Fuel Mix.** During 2005, coal was 56.4 percent, nuclear 34.2 percent, natural gas 5.9 percent, oil 1.2 percent, hydroelectric 1.7 percent, solid waste 0.6 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 is potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure.

Scarcity

- **Historical Scarcity Pricing.** Scarcity exists when supply is less than, or equal to, demand where demand includes a level of operating reserves. In PJM, scarcity pricing has resulted under these conditions as the result of the shape of the PJM aggregate supply curve. Scarcity pricing occurred, for example, in the summer of 1999 in PJM.

- **Scarcity in 2005.** In the summer of 2005, the first hot summer since the integrations of Phases 1 through 5, the dynamic in the PJM Energy Market changed. The change was due, in part, to the larger footprint. What had been PJM's entire Energy Market in 1999 was now just a regional part of the market. Units that might have been dispatched in 1999 to meet aggregate PJM load were dispatched in 2005 to resolve constraints associated with bringing lower cost power from the west to east. The result was that rather than units in the eastern part of PJM being dispatched in merit order to meet aggregate demand in the relatively small eastern part of PJM, the units were dispatched out of merit order to solve local constraints. The result, in turn, was that there was not a market mechanism to ensure that prices increased to reflect the scarcity conditions that existed on two occasions.

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, 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. 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 2005.** Operating reserve charges were significantly higher in 2005 than in prior years. The reasons for the observed increase in the operating reserve rate include increased fuel costs, unexpected transmission outages, unanticipated fluctuations in interchange transactions levels and market power.

Conclusion

Wholesale electric power markets, apparently without exception, are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability, typically measured as an acceptable loss of load probability level. This level of reliability is enforced through a requirement to maintain a target level of installed or unforced capacity, which, based on planning models, is considered to be a level that will produce the desired loss of load probability. 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 impact of having capacity in excess of the equilibrium level likely to result from the operation of an energy market alone 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 electricity market design.

While net revenue in PJM has been 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, net revenue has 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.

A capacity market is a formal market-based mechanism 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 also an explicit mechanism for valuing capacity and is preferable to non market and non-transparent mechanisms for that reason.

PJM's proposed 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 Markets.

A market design cannot be deemed truly successful until it results in the retirement and replacement of a significant portion of the existing investment in generating assets, based on incentives endogenous to the market design. The net revenue performance of the markets over six years illustrates that additional market modifications are necessary if PJM is to pass the ultimate test of a market, the successful provision of long-term incentives to invest.

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.[5] Gross Energy Market revenue is the product of the Energy Market price and generation output. Gross revenues are also received from the Capacity Markets 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 operations 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.

Table 3-1 illustrates the relationship between generator variable cost and net revenue from the PJM Energy Market alone for the years 1999 through 2005.

Table 3-1 - PJM Energy Market net revenue [By unit marginal cost (Dollars per installed MW-year)]: Calendar years 1999 to 2005

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

5 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.

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 real markets, net revenue fluctuates annually based on actual conditions in all relevant markets.

The net revenue analysis includes a natural gas-fired CT, a two-on-one natural gas-fired CC plant and a 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.

The net revenue analysis includes nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emission market credit 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 startup 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.[6] 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 startup 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.[7] 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.

6 A two-hour hot start, including a notification period, is consistent with the CC technology.
7 An eight-hour cold status notification plus startup is consistent with the CP technology.

Energy Market Net Revenue

The Energy Market revenues in Table 3-1 reflect net Energy Market revenues from all hours during 1999 to 2005 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.[8] For example, during 2005, if a unit had marginal costs (fuel plus variable operations and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2005, adjusted for forced outages, it would have received $241,977 per installed MW-year in net revenue from the Energy Market alone.

Figure 3-1 displays the information from Table 3-1. As Figure 3-1 illustrates, the Energy Market net revenue curve was higher in 2005 for every level of unit marginal costs compared to 2004. The 2005 net revenues for units with marginal costs equal to, or less than, $80 were higher than for any year since PJM introduced markets in 1999.

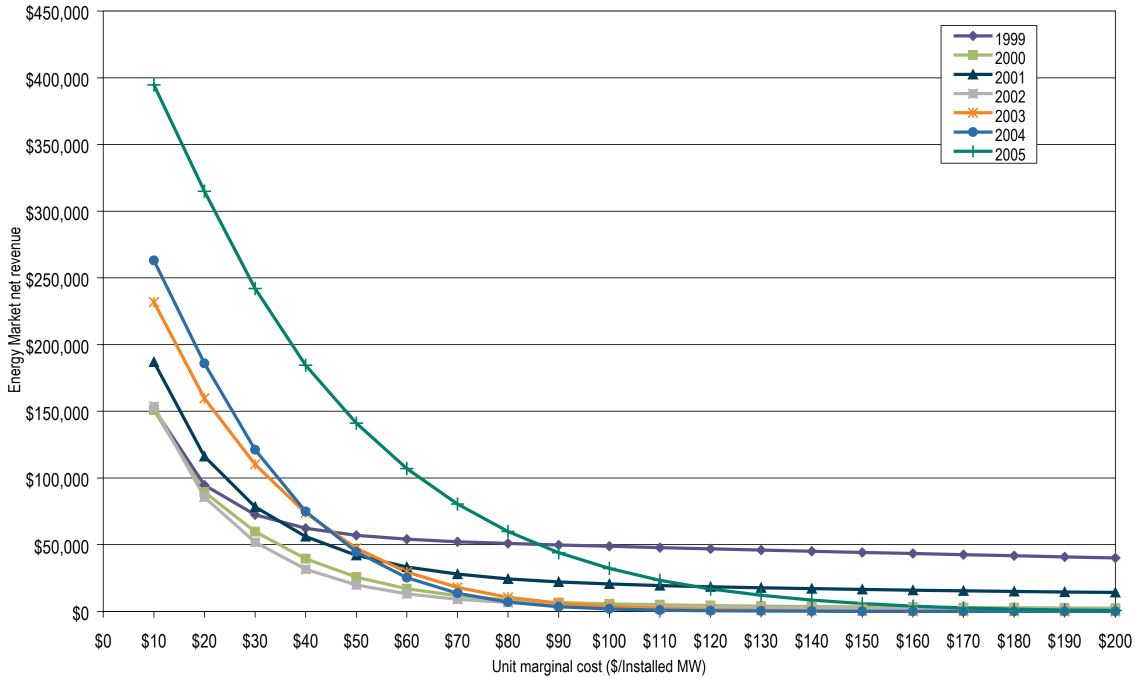
The increase in 2005 net energy revenue compared to 2004 is the result of changes in the frequency distribution of energy prices. In 2005, prices were greater than, or equal to, $30 more frequently than in any other year dating back to 1999. In 1999, LMP was greater than or equal to $30 per MWh during 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 and 81 percent in 2005.

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 $120 in 2005. An efficient CC could have produced energy at an average cost of $20 in 1999, but $85 in 2005. An efficient CP could have produced energy at an average cost of $20 in 1999, but $30 in 2005.

The 2005 load-weighted, average LMP for the PJM system was $63.46 per MWh compared to $44.34 in 2004. There were no price spikes in 2005. The system average hourly LMP exceeded $200 for 35 hours with the maximum LMP at $286.86.

8 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.

Figure 3-1 - PJM Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2005



Differences in the shape and position of net revenue curves for the six 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] Energy Market revenues for 2005 are significantly higher for units with marginal costs up to and including $80 than for any other year, 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.

Capacity 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 2005, PJM capacity resources received a weighted-average payment from the PJM Capacity Credit Markets of $6.12 per unforced MW-day, or $2,089 per MW-year of installed capacity. This is the lowest level of Capacity Market revenues since the opening of PJM Markets in 1999.

The PJM Capacity Market price used for net revenue calculations is the composite Capacity Market, excluding ComEd through May 31, 2005, and the entire PJM footprint from June 1, 2005, onward. The corresponding annual Capacity Market prices are presented in Table 3-2.

9 See Section 2, "Energy Market, Part 1," at "Load and LMP," for detailed data on the annual distribution of prices.

Table 3-2 - PJM's average annual Capacity Market price: Calendar years 1999 to 2005

	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

Ancillary Service and Operating Reserve Net Revenue

Generators also receive revenue from the sale of ancillary services, including those from the Spinning Reserve and Regulation Markets as well as black start and reactive services. Aggregate ancillary service revenues were $5,135 per installed MW-year in 2005, the highest level since the introduction of PJM Markets in 1999. (See Table 3-3.) 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 3-3 - System average ancillary service revenues: Calendar years 1999 to 2005

	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

Although not included in the net revenue analyses, generators also receive operating reserve revenues from both the Day-Ahead and Real-Time Energy Markets. Operating reserve payments were about $3,600 per installed MW-year in 2004 and were about $3,800 per installed MW-year in 2005. 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

The analysis of 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.

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 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 Capacity Market, 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 capacity auctions, by plant type.

NO_x and SO_2 credit 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 credit costs were obtained from actual historical daily spot cash prices for the prompt year.[15] NO_x credit costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 credit 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.

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 Strategic Energy Resources, 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 Strategic Energy Services, Inc. for PJM.

13 Strategic Energy Services, 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 L.L.C.

16 Outage figures obtained from the PJM eGADS database.

Variable operations 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 3-4.

Ancillary service revenues for the provision of spinning reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 spinning reserve in PJM. The same is true for the CC configuration. Steam units, like the coal plant, do provide Tier 1 spinning reserve, but the 2005 Tier 1 revenues were minimal. 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. 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 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 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 $2,248 per installed MW-year; for CCs, the calculated rate is $3,155 per installed MW-year and for CPs, the calculated rate is $1,692 per installed MW-year.[21]

Table 3-4 - Burner tip average fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2005

	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

17 Strategic Energy Services, Inc.

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

19 Gas daily cash prices obtained from Platt's.

20 Coal prompt prices obtained from Energy Argus for 1999 to 2004 and from Platt's for 2005.

21 The CT plant reactive revenues are based on 22 recent FERC filings for CT reactive costs. The CC plant revenues are based on 18 recent FERC filings for CC reactive costs, and the CP plant revenues are based on five recent FERC filings for CP reactive costs. These figures have been updated from those reported in the *2004 State of the Market Report* to include the large number of generators integrated into PJM from the AEP, DAY, DLCO and Dominion Control Zones as well as new generation in existing zones.

The perfect dispatch scenario total net revenues for 1999 to 2005 are shown in Table 3-5, Table 3-6 and Table 3-7 for the new entrant CT, CC and CP facilities, respectively.

Table 3-5 - New entrant gas-fired CT (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2005

	Energy	Capacity	Spin	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

Table 3-6 - New entrant gas-fired CC (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2005

	Energy	Capacity	Spin	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

Table 3-7 - New entrant CP (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2005

	Energy	Capacity	Spin	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

To demonstrate the sensitivity of the CT Energy Market net revenue results to the assumption of perfect dispatch with no operating constraints, 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 PJM 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 are 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 reserves based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the same variable operations and maintenance costs, outage, fuel cost, emissions and plant performance assumptions reflected in the Table 3-5 results.

A comparison of the results is shown in Table 3-8, where the first column in Table 3-8 is the perfect economic dispatch Energy Market net revenue results from Table 3-5. For the seven-year period, the average Energy Market net revenue under the perfect economic dispatch scenario was about $25,300 per installed MW-year while the seven-year average for the peak-hour dispatch scenario is about $17,000 per installed MW-year or about a 33 percent reduction in Energy Market net revenues. Additional, more complex dispatch scenarios were analyzed for the CT plant; however, the resultant effect on Energy Market net revenue was about the same as the results of the peak-hour dispatch scenario versus the perfect economic dispatch scenario.

Table 3-8 - Energy Market net revenues for a CT under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2005

	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%)
Average	$25,286	$16,955	($8,331)	(32.9%)

To demonstrate the sensitivity of the CC 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[24] 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 reserves 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 costs, outage, fuel cost, emissions and plant performance assumptions reflected in the Table 3-6 results.

22 Startup and shutdown fuel burn obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platt's fuel prices. Per PJM Manual M-15, "Cost Development Guidelines," Revision 5 (August 18, 2005), 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.

24 Startup and shutdown fuel burn obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platt's fuel prices. Per PJM Manual M-15, "Cost Development Guidelines," Revision 5 (August 18, 2005), 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.

A comparison of the results is shown in Table 3-9 where the first column in Table 3-9 is the perfect economic dispatch Energy Market net revenue results from Table 3-6. For the seven-year period, the average Energy Market net revenue under the perfect economic dispatch scenario was about $60,200 per installed MW-year while the seven-year average for the peak-hour dispatch scenario is about $41,200 per installed MW-year or about a 32 percent reduction in Energy Market net revenues. Additional, more complex dispatch scenarios were analyzed for the CC plant; however, the resultant effect on Energy Market net revenue was about the same as the results of the peak-hour dispatch scenario versus the perfect economic dispatch scenario.

Table 3-9 - Energy Market net revenues for a CC under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2005

	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%)
Average	$60,156	$41,189	($18,967)	(31.5%)

To demonstrate the sensitivity of the CP Energy Market net revenue results to the assumption of perfect dispatch with no operating constraints, 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 reserves, when applicable, since the assumed operation is under the direction of PJM operations. The additional dispatch scenario uses the same variable operations and maintenance costs, outage, fuel cost, emissions and plant performance assumptions reflected in the Table 3-7 results.[25]

A comparison of the results is shown in Table 3-10 where the first column in Table 3-10 is the perfect economic dispatch Energy Market net revenue results from Table 3-7. For the seven-year period, the average, Energy Market net revenue under the perfect economic dispatch scenario was about $136,700 per installed MW-year while the seven-year average for the available dispatch scenario is about $128,700 per installed MW-year or about a 6 percent reduction in Energy Market net revenues. The two scenarios are provided to present a reasonable bound of energy net revenues for a new entrant CP.

25 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.

Table 3-10 - Energy Market net revenues for a CP under two dispatch scenarios (Dollars per installed MW-year): Calendar years 1999 to 2005

	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	($11,505)	(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%)
Average	$136,656	$128,724	($7,932)	(5.8%)

Net Revenue Adequacy

To put the net revenue results in perspective, the first operating year's annual fixed costs for the assumed new entrant CT plant configuration would be about $61,700 per installed[26] MW-year or about $72,200 per installed MW-year if levelized over the 20-year life of the project.[27] The first operating year's annual fixed cost for the assumed CC and CP plant configurations would be about $80,000 per installed MW-year and $178,000[28] per installed MW-year, respectively. The levelized 20-year operating annual costs for the CC and CP plants would be about $93,500 per installed MW-year and $208,200 per installed MW-year, respectively. A tabulation of the first operating year and 20-year operating life levelized costs is shown in Table 3-11.[29]

Table 3-11 - 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	$61,726	$72,207
CC	$79,969	$93,549
CP	$178,019	$208,247

In 2005, under the perfect economic dispatch scenario, net revenue from the Energy Market, the Capacity Market and ancillary services for a new entrant CT were approximately $20,000 per installed MW-year. The associated operating costs were between $110 and $120 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $9.73 per MBtu and a VOM rate of $5 per MWh.[30] The resulting net revenue stream would not have covered the fixed costs of a new CT if it ran during all profitable hours.

26 Installed capacity at 92 degrees F.

27 This is the same analysis performed for PJM by Strategic Energy Services, Inc. during 2004 in the development of the cost of new entry for the reliability pricing model (RPM). After evaluation for current market conditions, there is little to no change in the project cost, and as such the 2004 study results are reasonable for 2005 analysis. 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 20-year modified accelerated cost-recovery schedule (MACRS). A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

28 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2005.

29 The figures in Table 3-11 represent the annual cost for the first year of operation. For example, the $61,726 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 $58,752 per installed MW-year.

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

In 2005, under the perfect economic dispatch scenario, net revenue from the Energy Market, the Capacity Market and ancillary services for a new entrant CC were approximately $73,500 per installed MW-year. The associated operating costs were between $75 and $85 per MWh, based on a design heat rate of 7,500 Btu per kWh, average daily delivered natural gas prices of $9.73 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 2005, under the perfect economic dispatch scenario, net revenue from the Energy Market, the Capacity Market and ancillary services for a new entrant CP would have been approximately $237,900 per installed MW-year. The associated operating costs would have ranged between $30 and $35 per MWh,[31] based on a design heat rate of 9,500 Btu per kWh, average delivered coal prices of $2.88 per MBtu and a VOM rate of $2 per MWh. This revenue stream would 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 of $61,700 per installed MW-year and $80,000 per installed MW-year, respectively. In 2000 and 2002 through 2005, 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 of $178,000 per installed MW-year.

Under the perfect economic dispatch scenario, the seven-year net revenue averaged $40,700 per installed MW-year for a new entrant CT plant, $76,000 per installed MW-year for a new entrant CC plant and $154,400 per installed MW-year for a new entrant CP plant. Thus, under perfect economic dispatch over the seven-year period, the average net revenue was not adequate to cover the first year's fixed costs for the CT, CC or CP plant.

Table 3-12 - CT 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2005

	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%
Average	$72,207	$40,724	56%	$32,393	45%

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

Table 3-13 - CC 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2005

	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%
Average	$93,549	$76,028	81%	$57,061	61%

Table 3-14 - CP 20-year levelized fixed cost vs. perfect dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2005

	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%
Average	$208,247	$154,368	74%	$146,436	70%

Table 3-12 through Table 3-14 show net revenues under the perfect dispatch and economic scenarios compared to the 20-year levelized fixed costs of each plant type. During the seven-year period from 1999 to 2005, the CT plant recovered 56 percent of the 20-year levelized fixed costs under the perfect dispatch scenario and 45 percent under the economic scenario. During that same period the CC plant recovered 81 percent of the fixed costs under the perfect dispatch scenario and 61 percent under the economic and the CP recovered 74 percent of the 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 2005 net revenue indicates that the fixed costs of new peaking and midmerit units were not fully covered, but that the fixed costs of new coal-fired baseload were covered. During the seven-year period 1999 to 2005, 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 prices and lower Capacity Market 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 20-year levelized fixed costs from Table 3-11. 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 3-15.[32]

Table 3-15 - 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	$77,207	14.0%	$98,549	13.5%	$218,247	13.3%
Base Case	$72,207	12.0%	$93,549	12.0%	$208,247	12.0%
Sensitivity 2	$67,207	9.9%	$88,549	10.4%	$198,247	10.7%
Sensitivity 3	$62,207	7.7%	$83,549	8.8%	$188,247	9.3%
Sensitivity 4	$57,207	5.2%	$78,549	7.1%	$178,247	7.9%
Sensitivity 5	$52,207	2.3%	$73,549	5.3%	$168,247	6.5%
Sensitivity 6	$47,207	(1.6%)	$68,549	3.3%	$158,247	4.9%

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.

32 This table is based on the same analysis performed for PJM by Strategic Energy Services, Inc. during 2004 in the development of the cost of new entry for the RPM. After evaluation for current market conditions, there is little to no change in the project cost, and as such the 2004 study results are reasonable for 2005 analysis. 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 20-year modified accelerated cost-recovery schedule (MACRS). A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

Existing and Planned Generation

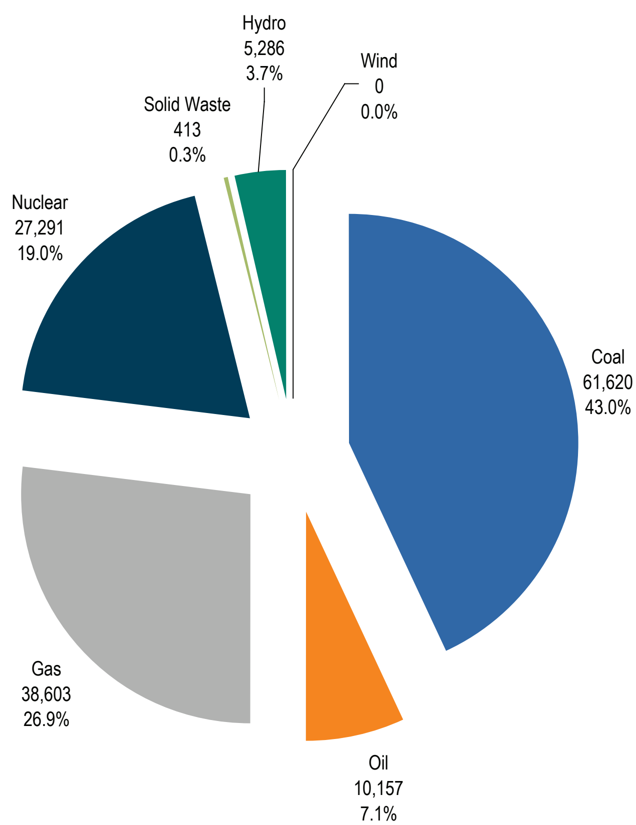
Installed Capacity and Fuel Mix at December 31, 2005

During calendar year 2005, primarily as a result of the integrations, PJM installed capacity increased from 143,370 MW on January 1 to 163,471 MW on December 31 and the fuel mix shifted slightly.

Installed Capacity

On January 1, 2005, PJM installed capacity[33] was 143,370 MW,[34] with a fuel mix that was 43.0 percent coal, 26.9 percent natural gas, 19.0 percent nuclear, 7.1 percent oil, 3.7 percent hydroelectric and 0.3 percent solid waste.[35] (See Figure 3-2.) This includes the newly integrated DLCO Control Zone as of January 1, 2005.

Figure 3-2 - PJM capacity (By fuel source): At January 1, 2005

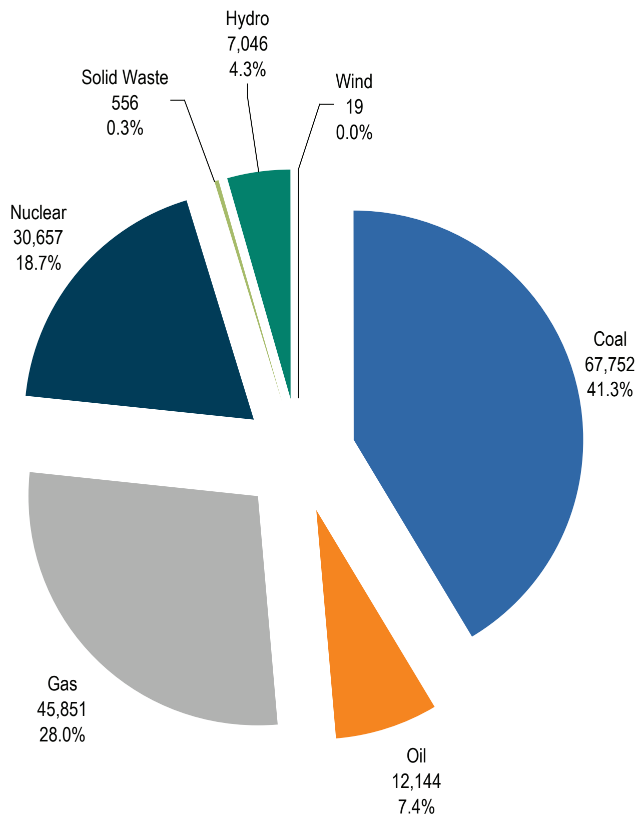


33 Installed capacity includes net capacity imports and exports and can vary on a daily basis.
34 These capacity values include the ComEd Control Zone.
35 Values in percent may not add to 100 because of rounding.

During Phase 4, unit retirements, rating changes and changes in capacity imports and exports resulted in an installed capacity increase of 1,218 MW. On April 30, 2005, installed capacity was 144,588 MW.

With the integration of Dominion on May 1, 2005, installed capacity increased by 19,436 MW to 164,024 MW, a 13.4 percent increase in total PJM capacity over the April 30 level. The Dominion Control Zone had proportionally more gas and hydroelectric generating capability and less coal and nuclear generating capability than PJM had prior to the Phase 5 integration. As a result, the gas share of total PJM installed capacity rose by 0.4 percent to 28.0 percent; the hydroelectric share increased by 0.9 percent to 4.3 percent and the oil share increased by 0.4 percent to 7.4 percent, while the coal share of capacity fell by 2.0 percent to 41.3 percent and the nuclear share declined 0.2 percent to 18.7 percent.[36] (See Figure 3-3.)

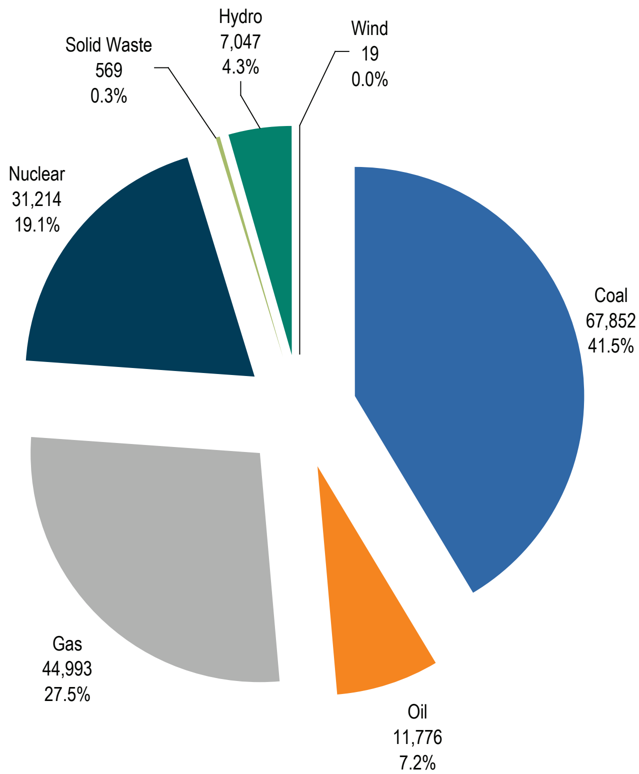
Figure 3-3 - PJM capacity (By fuel source): At May 1, 2005



36 Values in percent may not add to 100 because of rounding.

On December 31, 2005, PJM installed capacity was about 163,471 MW. Of the total installed capacity, 67,852 MW, or 41.5 percent, was coal; 44,993 MW, or 27.5 percent, was natural gas; 31,214 MW, or 19.1 percent, was nuclear; 11,776 MW, or 7.2 percent, was oil; 7,047 MW, or 4.3 percent, was hydroelectric; 569 MW, or 0.3 percent, was solid waste; and 19 MW, or 0.0 percent, was wind.[37] (See Figure 3-4.)

Figure 3-4 - PJM capacity (By fuel source): At December 31, 2005

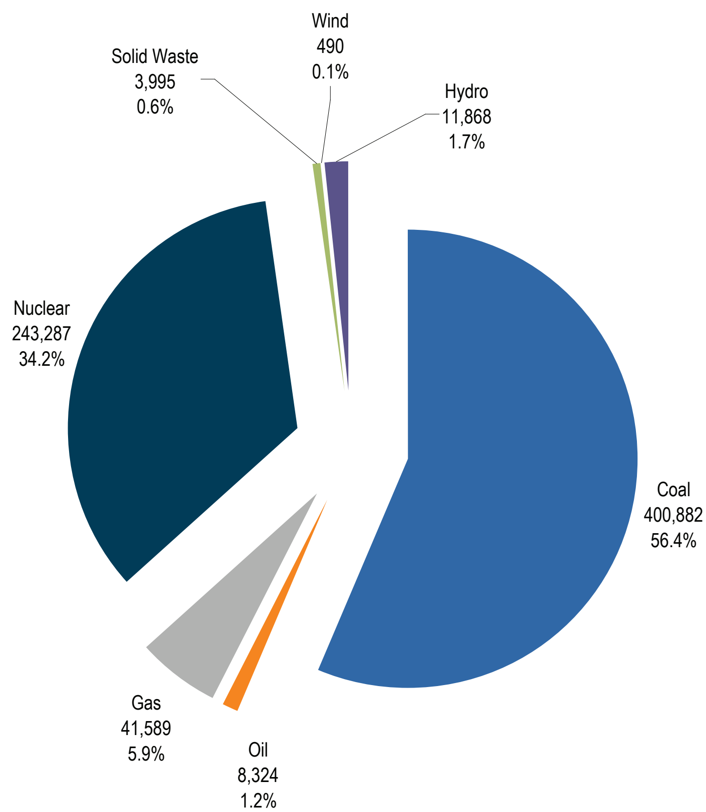


37 Although wind-based resources accounted for only 19 MW of the installed capacity in PJM on this date, in actuality, this value represents only 20 percent of wind capability in PJM. PJM administratively reduces the capabilities of all wind generators by 80 percent when determining the system installed capacity because they cannot be dispatched on demand.

Output by Fuel Source

In calendar year 2005, coal and nuclear units generated 90.6 percent of the total electricity. Coal was 56.4 percent, nuclear 34.2 percent, natural gas 5.9 percent, oil 1.2 percent, hydroelectric 1.7 percent, solid waste 0.6 percent and wind 0.1 percent of total generation.[38] (See Figure 3-5.)

Figure 3-5 - PJM generation [By fuel source (In GWh)]: Calendar year 2005



38 Values may not add to 100 percent due to rounding.

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 2005, about 24,300 MW of capacity were in generation request queues for construction through 2010, compared to an average installed capacity of 146,869 MW in 2005 and a year-end installed capacity of 163,471 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity. (See Table 3-16 .)

Table 3-16 - Year-to-year capacity additions: Calendar years 2000 through 2005

	Capacity Additions (MW)
2000	504
2001	1,068
2002	3,800
2003	3,521
2004	1,925
2005	777

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 April 1997 through March 1999; Queue B was open from April 1999 through September 1999 and Queue C opened in October 1999. After Queue C, a new queue was opened every six months. Queue P is currently active.

Capacity in generation request queues (See Table 3-17.) for the six-year period beginning in 2005 and ending in 2010 increased by approximately 12,100 MW from 15,500 MW in 2004 to 27,600 MW in 2005.[39, 40] Queued capacity scheduled for service in 2005 decreased from 4,906 MW to 3,151 MW, or 36 percent. Queued capacity scheduled for service in 2006 increased from 5,250 MW to 5,931 MW, or 13 percent. Capacity in the queues for the years 2007 and 2008 also increased in 2005 over 2004. Queued capacity scheduled for service in 2010 indicates that capacity is being planned further in the future than last year. In 2004, no projects were in queues projected to enter service later than 2008.

Table 3-18 shows the amount of capacity currently active, in service, under construction or withdrawn for each queue since the beginning of the regional transmission expansion planning (RTEP) process and the total amount of capacity that had been included in each queue.

Table 3-17 - Queue comparison (In MW): Calendar year 2004 vs. 2005

	MW in the Queue 2004	MW in the Queue 2005	Year-to-Year Change (MW)	Year-to-Year Change
2005	4,906	3,151	(1,755)	(36%)
2006	5,250	5,931	681	13%
2007	1,051	5,425	4,374	416%
2008	4,263	6,462	2,199	52%
2009	0	1,735	1,735	NA
2010	0	4,875	4,875	NA
Total	15,470	27,579	12,109	NA

39 See the *2004 State of the Market Report* (March 8, 2005), pp. 84-85, for the queues in 2004.
40 The 27,600 MW includes generation with scheduled in service dates in 2005 and earlier years net of generation that is in service earlier than scheduled.

Table 3-18 - Capacity in PJM queues (In MW): At December 31, 2005

Queue	Active	In Service	Under Construction	Withdrawn	Total
A Expired 31-Mar-98	0	8,086	750	18,145	26,981
B Expired 31-Mar-99	0	4,306	0	16,024	20,330
C Expired 30-Sep-99	0	0	436	4,104	4,540
D Expired 31-Mar-00	0	807	0	7,564	8,371
E Expired 30-Sep-00	0	779	0	17,512	18,291
F Expired 31-Mar-01	0	16	0	3,093	3,109
G Expired 30-Sep-01	640	340	525	21,893	23,398
H Expired 31-Mar-02	0	56	400	8,424	8,880
I Expired 30-Sep-02	105	38	8	4,863	5,014
J Expired 31-Mar-03	200	14	22	707	943
K Expired 30-Sep-03	55	221	468	2,033	2,777
L Expired 31-Mar-04	550	38	317	3,383	4,288
M Expired 30-Sep-04	1,354	20	5	2,934	4,313
N Expired 31-Mar-05	5,266	1,814	4	3,884	10,968
O Expired 30-Sep-05	7,002	81	3	662	7,748
P Expired 31-Mar-06	6,235	0	0	0	6,235
Total	21,407	16,616	2,938	115,225	156,186

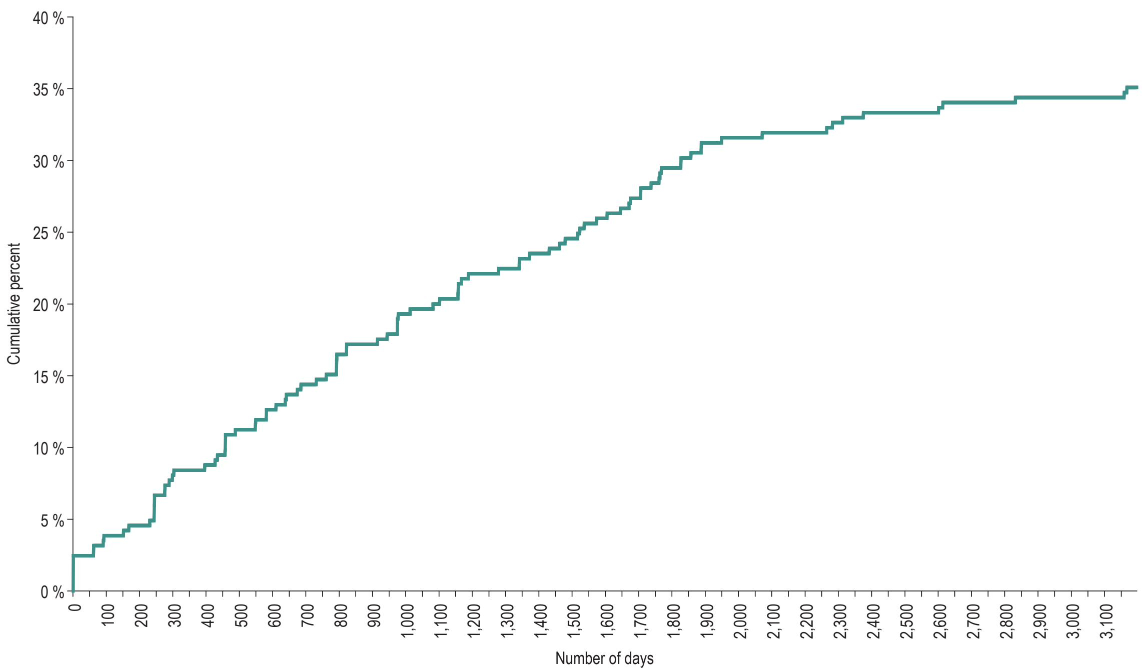
The data presented in Table 3-18 show that 75 percent of total in-service capacity from all the queues was from queues A and B and an additional 10 percent was from queues C, D and E. The data presented in Table 3-19 show that for successful projects there is an average time of 1,056 days (2.9 years) between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 809 days (2.2 years) between entering a queue and exiting. For each status, there is substantial variability around the average results.

Table 3-19 - Average project queue time: At December 31, 2005

Status	Average (Days)	Standard Deviation	Minimum	Maximum
In Service	1,056	802	0	3,196
Under Construction	1,210	688	278	3,200
Withdrawn	809	540	11	2,542
Active	364	294	95	1,739

Figure 3-6 shows the cumulative probability of completion of RTEP projects. Based on the data presented in Figure 3-6, 25 percent or more of the projects in the queues are completed by the time they have been in the queue 1,523 days. Likewise if a project has been resident in the queues for more than 3,167 days (total days to date), the probability that it will have been completed is 35 percent.

Figure 3-6 - RTEP project completion probability as function of days in queue



Distribution of Units in the Queues

Table 3-21 shows the RTEP projects under construction or active as of December 31, 2005, by unit type and control zone. Most (98 percent of the MW) of the steam projects (predominantly coal) are in the Western Region control zones (AEP, AP and ComEd). Most (64 percent of the MW) of the CC projects are in the Mid-Atlantic Region control zones (PECO, PSEG, AECO and JCPL). Wind projects are primarily in the AP, ComEd, PENELEC and PPL Control Zones. Wind projects account for approximately 8,700 MW of capacity or 36 percent of the capacity in the queues.[41]

41 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 wind resources means that only 17,400 MW of capacity are effectively in the queue of the 24,300 MW of generation currently active in the queues.

Table 3-20 - Existing PJM capacity [By zone and unit type (In MW)]

	Combined Cycle	Combustion Turbine	Diesel	Hyrdoelectric	Nuclear	Pumped Storage	Steam	Total
AECO	155	547	8	0	0	0	1,108	1,818
AEP	4,275	3,159	0	438	2,093	585	22,200	32,750
AP	1,129	1,202	43	80	0	0	7,879	10,333
BGE	0	872	0	0	1,735	0	2,793	5,400
ComEd	1,790	6,928	18	0	10,336	0	9,892	28,964
DAY	0	1,315	54	0	0	0	4,452	5,821
Dominion	3,369	3,226	105	562	3,432	3,606	8,162	22,462
DPL	1,088	705	85	0	0	0	1,882	3,760
DLCO	268	45	0	0	1,630	0	1,040	2,983
JCPL	1,677	1,226	0	0	619	400	10	3,932
MetEd	1,523	408	0	19	786	0	819	3,555
PECO	2,499	1,507	11	548	4,492	1,070	2,022	12,149
PENELEC	0	337	46	90	0	405	6,787	7,665
PEPCO	230	1,333	2	0	0	0	4,781	6,346
PPL	1,674	613	24	568	2,289	0	5,850	11,018
PSEG	2,022	2,920	15	11	3,353	0	3,003	11,324
Total	21,699	26,343	411	2,316	30,765	6,066	82,680	170,280

Table 3-20 shows existing generators by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity are distributed across all 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 (Table 3-21) and the location of units likely to retire. In the east, the capacity mix is likely to shift to more natural gas-fired CC and CT capacity. In the west, continued reliance on steam (mainly coal) seems likely.

Table 3-21 - Capacity additions in active or under-construction queues (In MW): At December 31, 2005

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Steam	Wind	Total
AECO	966	122	2	0	0	8	1,098
AEP	634	179	0	147	5,560	0	6,520
AP	640	0	23	0	1,122	1,451	3,236
BGE	0	0	5	0	0	0	5
ComEd	0	0	0	0	600	5,309	5,909
DAY	0	0	0	0	0	48	48
Dominion	1,275	0	29	431	0	0	1,735
DPL	0	0	13	0	1	0	14
JCPL	0	0	14	0	0	0	14
PECO	1,301	0	2	0	0	0	1,303
PENELEC	0	0	0	0	125	1,295	1,420
PEPCO	0	14	0	0	0	0	14
PPL	0	0	53	0	0	555	608
PSEG	2,351	55	7	0	0	11	2,424
Total	7,167	370	148	578	7,408	8,677	24,348

Table 3-22 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 50 percent of all current MW, steam units over 50 years of age comprise 87 percent of all MW over 50 years old and virtually 100 percent of such MW if run of river hydroelectric is excluded from the total. Steam units over 40 years of age comprise 89 percent of all such MW and 97 percent without run of river hydroelectric. Approximately 30 percent of steam units over 40 years old are located in the eastern PJM control zones.

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 east are replaced by units burning natural gas. Table 3-21 shows that in the eastern control zones, gas consuming unit types (CC and CT facilities) dominate the capacity additions.

Table 3-22 - PJM capacity age (In MW)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Run of River Hydroelectric	Nuclear	Pumped Storage Hydroelectric	Steam	Total
Less than 10	16,642	17,233	25	54	0	0	1,612	35,566
10 to 20	3,637	2,700	68	124	8,646	0	6,503	21,678
20 to 30	90	16	47	172	12,578	2,751	14,827	30,481
30 to 40	466	7,647	174	30	10,584	1,715	40,428	61,044
40 to 50	675	168	31	535	0	640	17,459	19,508
50 to 60	0	0	6	354	0	0	8,314	8,674
60 to 70	0	0	0	127	0	0	222	349
70 to 80	0	0	0	623	0	0	0	623
80 to 90	0	0	0	61	0	0	0	61
90 to 100	0	0	0	127	0	0	0	127
100 and over	0	0	0	29	0	0	0	29
Total	21,510	27,764	351	2,236	31,808	5,106	89,365	178,140

Table 3-23 shows the effect that the new generation in the queues will have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age will have retired by 2010. Nearly 50 percent of eastern generation will be from CC and CT generators, a 25 percent increase from today. Accounting for the fact that about 10 percent of steam units over 40 years old are gas-fired, the result will be an increase in the proportion of gas-fired capacity in the east from about 34 percent to about 43 percent.

Table 3-23 - Comparison of generators 40 years and older with slated capacity additions (In MW): Through 2010

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators All Ages	Percent of Area Total	Additional Capability through 2010	Estimated Capacity 2010	Percent of Area Total
East	Combined Cycle	675	7.3 %	10,638	20.7 %	4,618	14,581	29.8 %
	Combustion Turbine	168	1.8 %	9,178	17.8 %	177	9,187	18.7 %
	Diesel	27	0.3 %	143	0.3 %	91	207	0.4 %
	Run of River Hydro	946	10.2 %	1,146	2.2 %	0	1,146	2.3 %
	Nuclear	0	0.0 %	11,539	22.4 %	0	11,539	23.5 %
	Pumped Storage Hydro	400	4.3 %	1,470	2.9 %	0	1,470	3.0 %
	Steam	7,039	76.1 %	17,362	33.7 %	1	10,324	21.1 %
	Wind	0	0.0 %	0	0.0 %	574	574	1.2 %
	East Total	9,255	100.0 %	51,476	100.0 %	5,461	49,028	100.0 %
South	Combined Cycle	0	0.0 %	3,369	15.6 %	1,275	4,644	22.5 %
	Combustion Turbine	0	0.0 %	3,226	15.0 %	0	3,226	15.6 %
	Diesel	0	0.0 %	105	0.5 %	29	134	0.6 %
	Run of River Hydro	562	18.0 %	562	2.6 %	431	993	4.8 %
	Nuclear	0	0.0 %	3,432	16.0 %	0	3,432	16.6 %
	Pumped Storage Hydro	0	0.0 %	2,646	12.3 %	0	2,646	12.8 %
	Steam	2,552	82.0 %	8,162	38.0 %	0	5,610	27.1 %
	Wind	0	0.0 %	0	0.0 %	0	0	0.0 %
	South Total	3,114	100.0 %	21,502	100.0 %	1,735	20,685	100.0 %
West	Combined Cycle	0	0.0 %	7,692	7.2 %	1,274	8,966	8.4 %
	Combustion Turbine	0	0.0 %	15,671	14.7 %	193	15,864	14.8 %
	Diesel	10	0.1 %	163	0.2 %	28	181	0.2 %
	Run of River Hydro	348	2.0 %	608	0.6 %	147	755	0.7 %
	Nuclear	0	0.0 %	16,837	15.8 %	0	16,837	15.7 %
	Pumped Storage Hydro	240	1.4 %	990	0.9 %	0	990	0.9 %
	Steam	16,404	96.5 %	64,364	60.6 %	7,407	55,367	51.7 %
	Wind	0	0.0 %	0	0.0 %	8,103	8,103	7.6 %
	West Total	17,002	100.0 %	106,325	100.0 %	17,152	107,063	100.0 %
Grand Total		29,371		179,303		24,348	176,776	

Scarcity

Scarcity exists when supply is less than, or equal to, demand where demand includes a level of operating reserves. In PJM, scarcity pricing has resulted under these conditions as the result of the shape of the PJM aggregate supply curve. Scarcity pricing occurred, for example, in the summer of 1999 in PJM. As demand increased, prices rose to $900 per MWh and above. Offer capping for local market power did not affect scarcity pricing in 1999 as increased demand resulted in aggregate market prices that exceeded offer caps for local constraints. There were units with high offers, required to meet the aggregate demand for energy in PJM, that were not required to resolve local transmission constraints and therefore were not offer capped.

In the summer of 2005, the first hot summer since the integrations of Phases 1 through 5, the dynamic in the PJM Energy Market changed. The change was due in part to the larger footprint. PJM's peak load in the summer of 2005 was 130,000 MW while PJM's peak load in the summer of 1999 was 50,000 MW. What had been PJM's entire Energy Market in 1999 was now just a regional part of the market. Units that might have been dispatched in 1999 to meet aggregate PJM load were dispatched in 2005 to resolve constraints associated with bringing lower cost power from the west to east. Rather than import and ramp limits constraining power flows, PJM redispatched units up in the east and down in the west. The result was that rather than units in the eastern part of PJM being dispatched in merit order to meet aggregate demand in the relatively small eastern part of PJM, the units were dispatched out of merit order to solve local constraints. The result, in turn, was that there was not a market mechanism to ensure that prices increased to reflect the scarcity conditions that existed on two occasions.

This set of events led to the conclusion that PJM needed to implement an administrative scarcity pricing mechanism to ensure the appropriate tradeoff between limiting local market power and market prices that reflect scarcity conditions.[42]

In PJM's Energy Market, reliability on very high-load days has been the result of a combination of market-based responses to higher prices by both demand and supply and of administrative emergency actions. There is some demand-side response to high prices as loads voluntarily curtail when they have an incentive to do so and there is some supply-side response to high prices as generators produce more and imports increase. When market-based responses are not adequate, PJM has employed emergency procedures to effectively force supply and demand to match to prevent loss of load.

PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions. These emergency procedures include: emergency energy request events; maximum emergency generation events; manual load dump events; and voltage reduction events.

42 114 FERC ¶61,076 (2006).

Based on the implementation of one or more of these emergency actions over an area consisting of two or more contiguous zones with 5 percent or greater positive distribution factor ("dfax") relative to concurrently binding 500 kV or greater transmission constraints, conditions on two separate days in the summer of 2005 met the definition of scarcity.

There are four emergency messages that reflect scarcity as they have been implemented by PJM.[43] (See Table 3-24.)

In 2005 there were two high-load days with a number of hours that had one or more of the four emergency messages that reflected conditions in two or more contiguous zones with 5 percent or greater positive distribution factor relative to one or more concurrently binding 500 kV or greater transmission constraints.[44] The two days with potential scarcity pricing event hours in 2005 were July 26 and July 27. Of the four types of potential scarcity related emergency action triggers, two types occurred on these days: voltage reduction and maximum emergency generation loaded.

Table 3-24 -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

43 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.

44 *PJM Interconnection, L.L.C.*, Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005) defined criteria for additional scarcity pricing: "Additional Scarcity Pricing Regions must meet the following criteria: (l) consist of at least two entire transmission zones; (2) consist of contiguous transmission zones and sub-zones; (3) transmission import or transfer must be limited by EHV (500 kV or greater) constraints; and (4) consist of pricing nodes that have a 5 percent or greater positive dfax relative to the constraints." The expression transmission zone is synonymous with control zone as used in this report. The Settlement Agreement was approved by the FERC. 114 FERC ¶ 61,076 (January 27, 2006).

July 26 was the first of the two high-load days in 2005 with conditions that were consistent with this definition of scarcity. Figure 3-7 shows PJM's zonal LMPs by hour for July 26, 2005. BGE had the highest zonal hourly price of the day at $283 in the hour ending 1800. BGE load peaked in the same hour at 6,841 MW.

Figure 3-7 - Zonal hourly LMP: For July 26, 2005

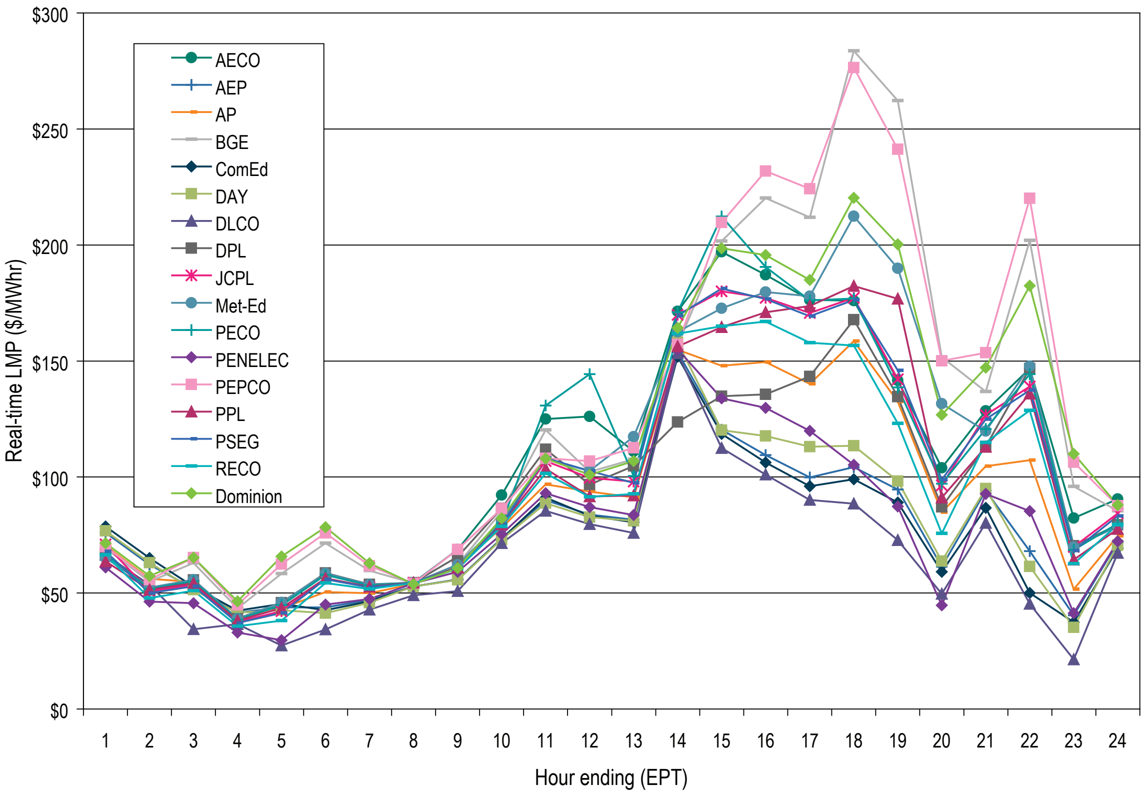
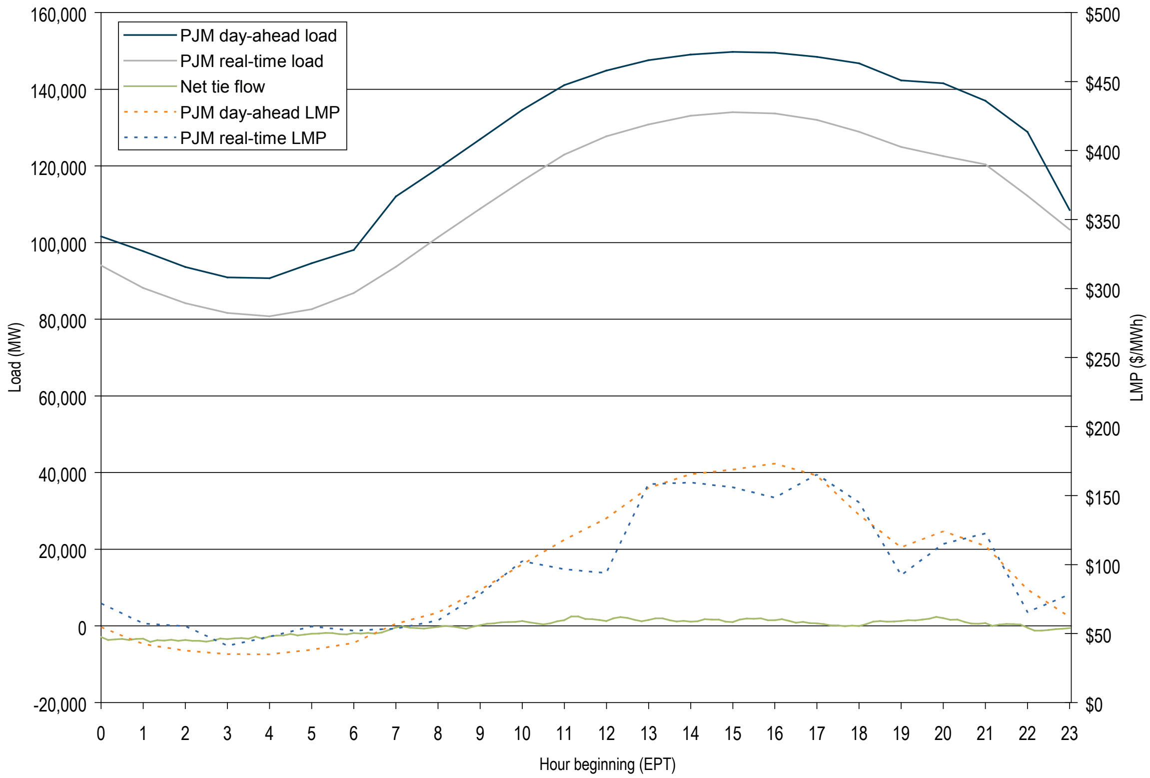


Figure 3-8 shows PJM's hourly load and LMP for both Day-Ahead and Real-Time Markets on July 26. Figure 3-8 also shows the net tie flows by hour on July 26.

Figure 3-8 - PJM load and LMP: For July 26, 2005



Ten 500 kV or greater transmission constraints were active over the day at various hours on July 26. Two contiguous transmission zones[45] in the Mid-Atlantic Region, BGE and PEPCO, had a maximum emergency generation loaded action concurrently in effect for approximately two hours (1636 through 1830).

BGE combined with PEPCO could qualify as a region with scarcity conditions under the definition of scarcity. BGE and PEPCO are two contiguous transmission zones containing generator buses with 5 percent or greater positive distribution factor relative to 500 kV or greater transmission constraints, including Bedington-Black Oak. To the extent that the BGE and PEPCO Control Zones meet this definition and to the extent that the emergency messages related to the BGE and PEPCO zones affected this area, July 26 had two hours in which scarcity existed.

July 27 was the second day in 2005 with conditions consistent with the FERC-approved definition of scarcity.

45 The term transmission zone is generally identical to control zone.

Figure 3-9 shows PJM's zonal LMPs by hour for July 27, 2005. PEPCO had the highest zonal hourly price of the day at $512 in the hour ending 1400. PEPCO load peaked in the same hour at 6,666 MW. Figure 3-10 shows PJM's hourly load and LMP for both the Day-Ahead and Real-Time Markets on July 27.

Figure 3-9 - Zonal hourly LMP: For July 27, 2005

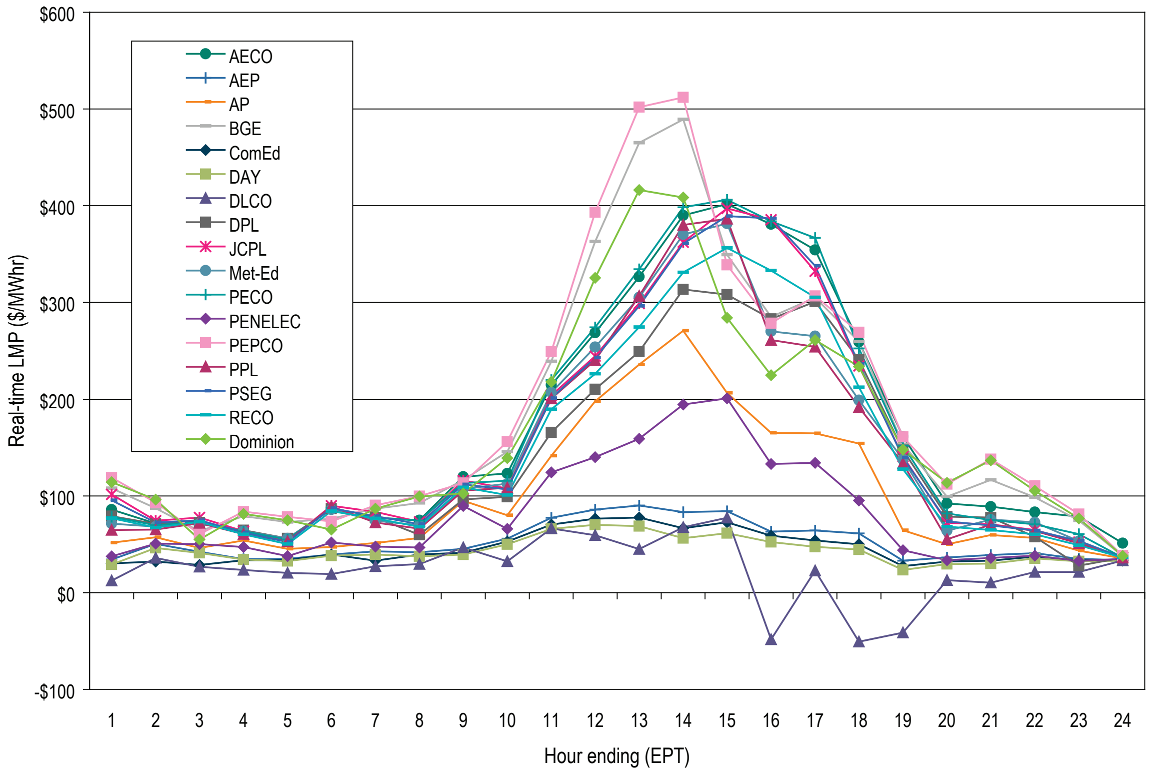
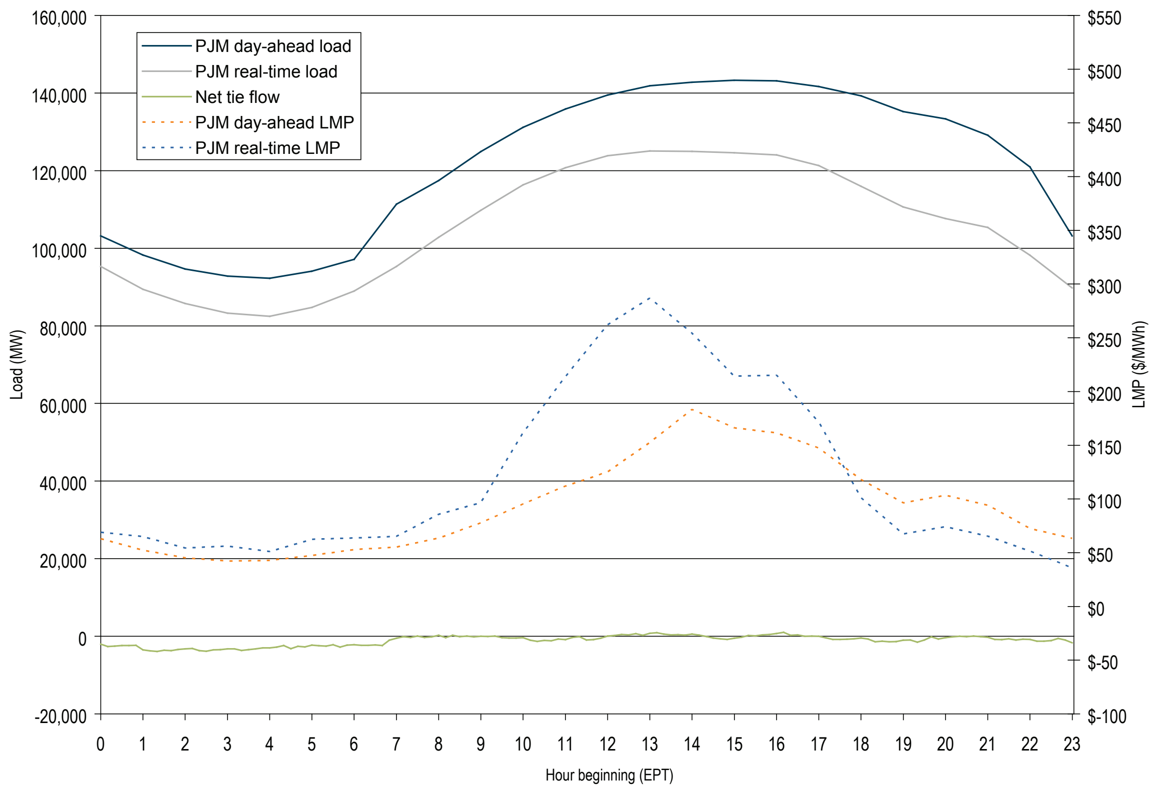


Figure 3-10 also shows the net tie flows by hour on July 27. Eleven 500 kV or greater transmission constraints were active over the day at various hours on July 27.

Figure 3-10 - PJM load and LMP: For July 27, 2005



Between the hours of 1300 and 2000 PJM had a number of active and overlapping scarcity-related emergency messages in effect on July 27. The BGE, PEPCO, Dominion and Potomac Edison had a voltage reduction event that started at 1339. At 1421 PSEG, PECO, JCPL and the eastern portion of PPL also had a voltage reduction event start. The voltage reduction events continued in BGE, PEPCO, Dominion, Potomac Edison, PSEG, PECO, JCPL and eastern PPL concurrently until 1730. BGE and PEPCO had a maximum emergency generation loaded event start at 1340. At 1400 PSEG, PECO, JCPL and eastern PPL also had a maximum emergency generation loaded event start. The voltage reduction events continued in BGE, PEPCO, PSEG, PECO, JCPL and eastern PPL concurrently until 1755.

Combined, BGE, PEPCO, PSEG, PECO, JCPL and eastern PPL comprise a contiguous subset of the Mid-Atlantic Region and Dominion is contiguous with the Mid-Atlantic Region. This area includes two or more contiguous transmission zones containing generator buses with 5 percent or greater positive distribution factor relative to 500 kV or greater transmission constraints. To the extent that these zones met this definition and to the extent that the emergency messages affected this area, July 27 had from 3.5 to 4.5 hours during which scarcity existed.

Operating Reserves

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 based on its offer and the revenues that result from that operation are insufficient to cover all the components of that offer, including startup and no-load, operating reserve credits ensure that all offer components are covered.[46] In addition, if a generator is scheduled for operation in the Real-Time Energy Market and it operates as directed by PJM dispatchers, it is eligible to receive operating reserve credits when its corresponding revenues are not sufficient to cover its offer.

The level of operating reserve credits paid to specific units depends on their offer level and 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. Such PJM operator decisions also interact with unit offer levels and operating parameters to affect operating reserve payments.

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 PJM MMU has analyzed operating reserve charges and credits. 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.

46 Operating reserve credits are also provided for pool-scheduled energy transactions, for generating units operating as condensers not as spinning 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 reserves.

Credits and Charges

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 3-25 shows the categories of credits and charges and their relationship.

Table 3-25 - Operating reserve credits and charges

Credits		Charges	
Day-Ahead:			
Day-Ahead Energy Market		Day-Ahead Demand	
Day-Ahead Congestion		Decrement Bids	
Day-Ahead Transactions		Day-Ahead Exports	
Synchronous Condensing		Real-Time Load	
		Real-Time Exports	
Balancing :			
Balancing Energy Market		Real-Time Deviations	
Balancing Congestion		from Day-Ahead Schedules:	
Lost Opportunity Cost			
Real-Time Import Transactions	**Day-Ahead**		**Real-Time**
		Net Deviation of Total	
	Day-Ahead Decrement Bids		Real-Time Load
	Day-Ahead Load	Demand	Real-Time Sales
	Day-Ahead Sales		Real-Time Exports
	Day-Ahead Exports		
	Day-Ahead Increment Bids	Supply	Real-Time Purchases
	Day-Ahead Purchases		Real-Time Imports
	Day-Ahead Imports		
	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 transaction credits.

The operating reserve charges that result from paying day-ahead operating reserve credits for an operating day are allocated to PJM members in proportion to their total cleared day-ahead demand, decrement bids and day-ahead exports for that operating day.

Synchronous Condensing Credits and Charges

Synchronous condensing credits are provided to eligible synchronous condensers for condensing and energy use costs if PJM dispatches them for purposes other than spinning 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 their real-time load plus real-time export transactions.

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. Daily balancing operating reserve credits are paid to generation resources that operate at PJM's request. If the total payment from the markets is less than the resource's offer, the difference is credited to the PJM member. Lost opportunity cost credits are paid to generation resources when their output is reduced or suspended by PJM for reliability purposes. Like generation resources, real-time import transactions receive balancing operating reserve credits if the total payments received from the markets are less than the real-time offer. Balancing operating reserve credits are also paid to canceled, pool-scheduled resources, to resources providing quick start reserves and to resources performing annual scheduled black start tests.

The operating reserve charges that result from paying balancing operating reserve credits are allocated to real-time hourly deviations from cleared quantities in the Day-Ahead Market. 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.** Deviations in the demand category equal the absolute value of the difference between the sum of the MW quantity of cleared, day-ahead load plus the day-ahead sale transactions scheduled through eSchedules[47] and the Enhanced Energy Scheduler (EES)[48] plus the cleared decrement bids in the Day-Ahead Market and the sum of the MW quantity of real-time load plus real-time sale transactions scheduled through eSchedules and the EES.

47 PJM's eSchedules is an application used by participants for internal bilateral transactions.
48 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

- **Supply.** Deviations in the supply category equal the absolute value of the difference between the sum of the MW quantity of the day-ahead purchase transactions scheduled through eSchedules and EES plus the cleared increment offers in the Day-Ahead Market and the sum of the MW quantity of real-time purchase transactions scheduled through eSchedules and EES.

- **Generator.** Deviations in the generator category equal the absolute value of the difference between a unit's cleared, day-ahead generation and a unit's hourly, integrated real-time generation. More specifically, a unit has 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 ineligible to set LMP for at least one five-minute interval during an hour.

Operating Reserve Credits and Charges

Table 3-26 shows total Energy Market operating reserve credits from 1999 through 2005, a period during which significant market changes occurred.[49] Energy Markets that clear based on market-based generator offers were 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.

Table 3-26 also shows the ratio of total operating reserve charges to the total value of PJM market billings. This ratio decreased from 4.4 percent in 2004 to 2.7 percent in 2005. Over the last seven years, this ratio ranged from a low of 2.7 percent in 2005 to a high of 7.5 percent in 2001.

Table 3-26 - Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2005

	Day-Ahead Energy Market Credit	Balancing Energy Market Credit	Total Energy Market Credit	Annual Credit Change	Operating Reserves as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	NA	$53,588,547	$53,588,547	NA	3.0%	NA	NA	NA	NA
2000	$60,028,266	$86,737,177	$146,765,443	174%	6.5%	$0.34	NA	$0.53	NA
2001	$80,165,425	$170,960,879	$251,126,304	71%	7.5%	$0.27	(20%)	$1.07	100%
2002	$60,148,379	$128,932,236	$189,080,615	(25%)	4.0%	$0.16	(40%)	$0.79	(26%)
2003	$87,309,127	$186,594,404	$273,903,531	45%	4.0%	$0.23	38%	$1.20	52%
2004	$129,230,218	$249,463,523	$378,693,741	38%	4.4%	$0.23	2%	$1.24	3%
2005	$59,614,645	$540,978,140	$600,592,785	59%	2.7%	$0.08	(67%)	$2.76	123%

49 Table 3-26 in Balancing Energy Market Credit includes only Balancing Energy Market credits and Balancing Congestion credits. Day-Ahead Energy Market Credits include Day-Ahead Energy Market and Day-Ahead Congestion credits, but not Day-Ahead Transactions credits. Reported credits include all billing adjustments made by PJM. The categories are defined in Table 3-25.

Finally, Table 3-26 shows Day-Ahead Energy Market and balancing Energy Market operating reserve total credits and credits per MWh for each full year after the introduction of the Day-Ahead Energy Market. The day-ahead operating reserve rate decreased $0.15 per MWh or about 67 percent from $0.23 per MWh in 2004 to $0.08 per MWh in 2005. The balancing operating reserve rate increased $1.52 per MWh, or about 123 percent, from $1.24 per MWh in 2004 to $2.76 per MWh in 2005.

Table 3-27 compares monthly operating reserve charges by category for calendar years 2004 and 2005. Charges to day-ahead demand, day-ahead exports and decrement bids fell by 54 percent between 2004 and 2005. Charges to real-time load and export transactions increased by 80 percent between 2004 and 2005. Charges to real-time deviations from day-ahead schedules increased by 119 percent between 2004 and 2005. In 2005, charges paid by real-time deviations from their day-ahead schedules represent 87 percent of all 2005 balancing operating reserve charges.

Table 3-27 - Operating reserve charges: Calendar years 2004 and 2005

	2004			2005		
	Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	Real-Time Load and Real-Time Exports	Real-Time Deviations from Day-Ahead Schedules	Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	Real-Time Load and Real-Time Exports	Real-Time Deviations from Day-Ahead Schedules
Jan	$7,237,378	$1,176,853	$42,111,918	$9,567,053	$4,424,843	$37,895,417
Feb	$5,047,471	$551,907	$12,280,720	$3,358,460	$1,720,120	$18,965,471
Mar	$5,181,393	$298,198	$5,116,105	$3,116,002	$1,289,212	$15,360,115
Apr	$2,874,680	$241,961	$10,690,944	$2,847,685	$1,097,556	$12,110,506
May	$7,680,241	$591,312	$27,159,818	$7,582,892	$242,506	$14,646,225
Jun	$13,049,234	$629,545	$30,532,300	$3,043,378	$2,379,770	$58,066,579
Jul	$14,015,970	$355,084	$24,904,235	$2,672,044	$2,680,880	$99,637,963
Aug	$12,966,963	$956,168	$23,549,491	$2,202,173	$3,609,806	$81,020,542
Sep	$8,600,746	$989,893	$15,643,643	$3,035,763	$2,530,569	$76,143,552
Oct	$18,757,488	$588,543	$11,656,103	$5,339,286	$2,141,759	$96,352,636
Nov	$17,128,598	$2,279,189	$15,554,421	$5,493,441	$979,360	$32,242,377
Dec	$16,690,058	$4,560,653	$46,306,867	$11,356,498	$751,026	$37,809,385
Total	$129,230,220	$13,219,306	$265,506,565	$59,614,675	$23,847,406	$580,250,768
Share of Annual Charges						
	31.68%	3.24%	65.08%	8.98%	3.59%	87.43%

Real-Time 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 3-28 shows monthly real-time deviations for demand, supply and generator categories for 2004 and 2005. Demand deviation is the largest category while generator deviation is the smallest. From 2004 to 2005, the share of total deviations increased in the demand category by 3.11 percentage points, fell in the supply category by 7.03 percentage points and increased in the generator category by 3.92 percentage points.

Total deviations in 2005 exceeded total 2004 levels from January through April and were less than 2004 levels from October through December.

Table 3-28 - Monthly balancing operating reserve deviations: Calendar years 2004 and 2005

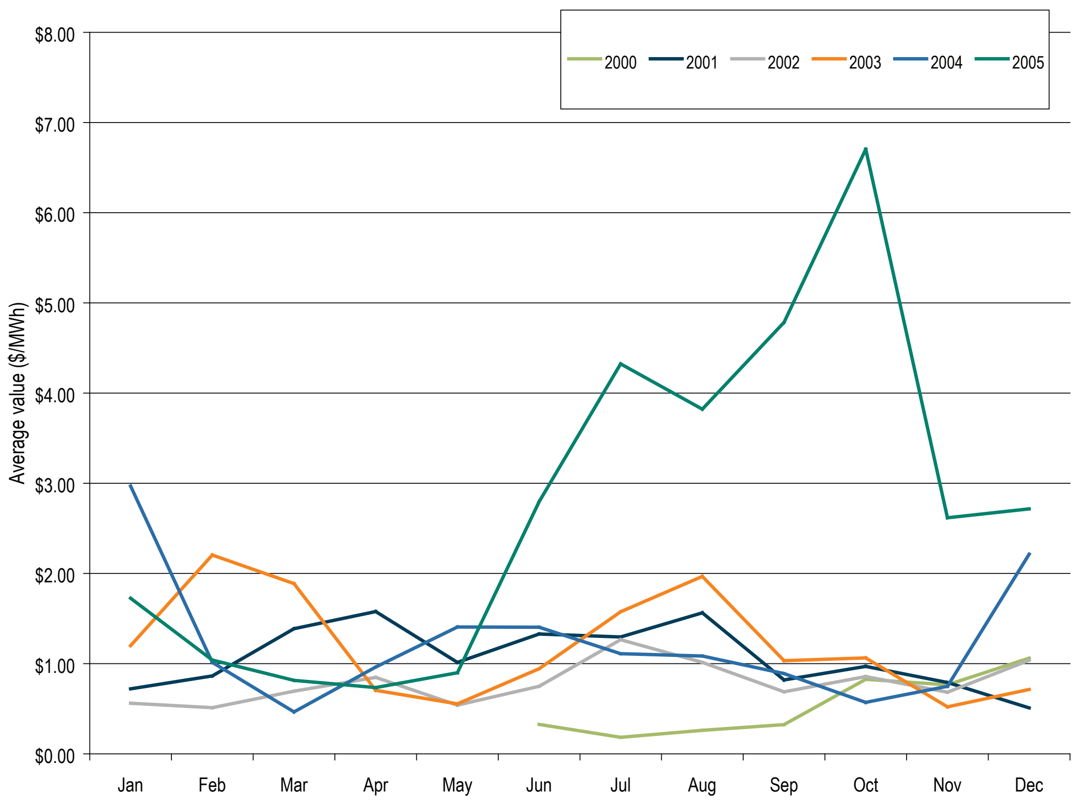
	2004 Deviations			2005 Deviations		
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)
Jan	6,574,494	4,539,070	2,390,883	11,851,254	6,717,597	3,144,258
Feb	5,583,195	4,266,677	1,843,279	9,505,119	5,366,922	3,241,208
Mar	5,755,515	3,467,472	1,889,581	10,367,348	5,198,926	3,637,017
Apr	5,605,423	3,230,722	2,116,433	8,522,724	4,867,238	3,120,261
May	10,311,309	6,070,625	2,473,952	9,280,079	3,893,888	3,395,250
Jun	11,778,882	6,806,620	2,544,211	11,394,615	4,863,249	4,121,267
Jul	12,189,090	7,413,096	2,449,265	13,110,625	5,485,019	4,191,367
Aug	11,474,810	7,314,993	2,411,749	12,021,176	4,702,635	3,783,214
Sep	9,059,839	5,579,295	2,220,747	9,155,776	3,770,614	3,187,321
Oct	10,362,779	6,386,254	3,357,123	7,745,326	3,216,032	2,776,153
Nov	10,583,716	6,262,230	3,904,595	6,971,279	2,822,426	2,343,019
Dec	10,790,676	6,560,068	3,326,017	7,951,859	2,897,055	2,627,646
Total	110,069,728	67,897,122	30,927,835	117,877,180	53,801,601	39,567,981
Share of Annual Deviations						
	52.69%	32.50%	14.81%	55.80%	25.47%	18.73%

Balancing Operating Reserve Rate

The balancing operating reserve rate equals the total amount of balancing operating reserve credits divided by total deviations. It is calculated daily. Figure 3-11 shows monthly average balancing operating reserve rates for the past six years. A large increase in the monthly average balancing operating reserve rate occurred between June and November 2005. The monthly average rate was at its maximum in October 2005 when it reached of $6.70 per MW. The growth in the monthly average rate resulted from an increase in total balancing operating reserve and a decrease in total generator deviations.

The reasons for the observed increase in the operating reserve rate include increased fuel costs, unexpected transmission outages, unanticipated fluctuations in interchange transactions levels and market power.

Figure 3-11 - Monthly average balancing operating reserve rate: June 1, 2000, through December 31, 2005



PJM Installed Capacity and Operating Reserve Credits

Table 3-29 shows the proportion of balancing operating reserve credits received by unit type, the proportion of MW in each unit type receiving balancing operating reserves and the proportion of total PJM capacity by unit type that receives balancing operating reserve payments. CT units received about 53 percent of balancing operating reserve credits although they represented only about 27 percent of the capacity receiving such credits and only 17 percent of total, PJM installed capacity. Steam units received about 21 percent of balancing operating reserve credits, but represented 49 percent of capacity receiving such credits and about 32 percent of total, PJM installed capacity.

Table 3-29 - Installed capacity percentage (By unit type): Calendar year 2005

	Share of Balancing Operating Reserve Credits	Share of Capacity Received Operating Reserve Credits	Share of Total PJM Capacity
CC	25.76%	19.06%	12.23%
CT	52.99%	26.70%	17.14%
Diesel	0.49%	0.24%	0.16%
Nuclear	0.21%	4.79%	3.08%
Steam	20.55%	49.20%	31.57%
Total	100.00%	100.00%	64.18%

Economic and Non-Economic Generation

Non-economic generation includes units that are producing energy but at a higher offer price than the LMP. Economic generation, conversely, includes units producing energy at an offer price less than, or equal, to LMP. The level of non-economic generation is an indicator of the level of generation run for operating reserves. The data are hourly and do not reflect the fact that operating reserve credits are calculated daily. As a result, some generation that is non-economic for an hour may receive adequate market revenues during other hours to offset any shortfall.[50]

50 Self-scheduled units were not included in either economic or non-economic categories.

Figure 3-12 shows PJM hourly average economic and non-economic generation for 2005. It shows that on hourly average PJM has approximately 5,000 MW of non-economic generation and 40,000 MW of economic generation.

Figure 3-12 - PJM hourly average economic and non-economic generation: Calendar year 2005

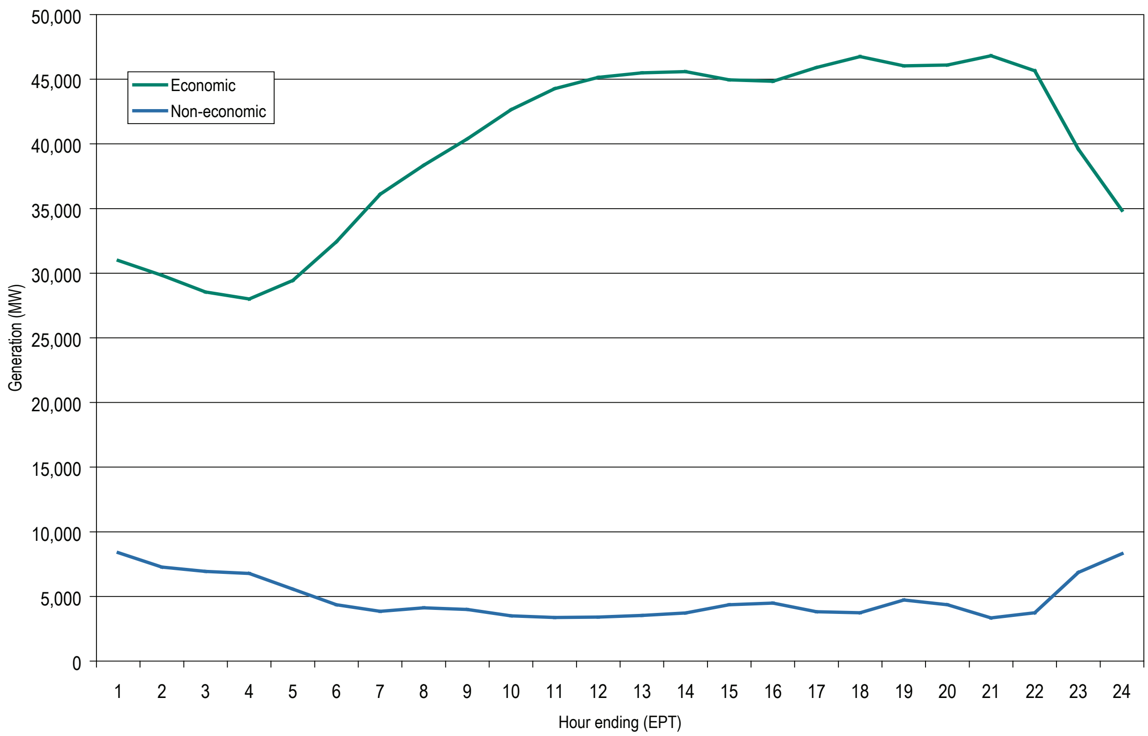


Table 3-30 presents the percentage of total PJM economic and non-economic generation by unit type. During 2005, steam units represented 87 percent of economic generation and about 75 percent of non-economic generation.

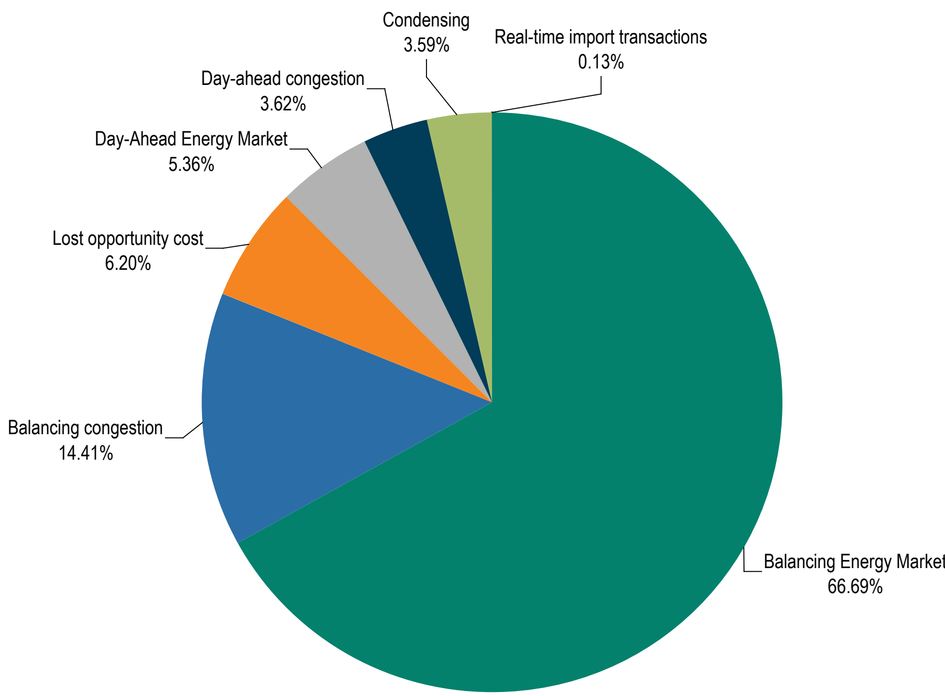
Table 3-30 - PJM economic and non-economic generation: Calendar year 2005

	Economic Generation	Non-Economic Generation
CC	3.50%	14.47%
CT	0.54%	8.35%
Diesel	0.01%	0.09%
Hydro	0.15%	0.00%
Steam	87.28%	74.50%
Nuclear	8.52%	2.59%
Total	100.00%	100.00%

Operating Reserve Credits by Category

Figure 3-13 shows that, at 67 percent, the largest share of total operating reserve credits was paid to resources in the balancing Energy Market during 2005. The next largest share, 14 percent, went to units providing balancing congestion relief. Credits to units for lost opportunity cost were 6 percent of all credits while credits to resources in the Day-Ahead Energy Market were 5 percent, for providing congestion relief in the Day-Ahead Market were 4 percent of all credits and for providing synchronous condensing were 4 percent. The smallest credit share went to real-time import transactions.

Figure 3-13 - Operating reserve credits: Calendar year 2005



Geography of Balancing Operating Reserve Charges and Credits

Table 3-31 compares the share of balancing operating reserve charges paid by and credits[51] 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. 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, 45 percent of all generator charges are paid by generators in the Mid-Atlantic Region and 71 percent of all generator credits are paid to generators in the Mid-Atlantic Region. Table 3-31 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator credits are 83 percent of all operating reserve credits while generator charges are 15 percent of all operating reserve charges.

Table 3-31 - Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2005

	Mid-Atlantic Region		Other Control Zones			
	Generation Charge	Generation Credit	Generation Charge	Generation Credit	Generation Charges Share of Total Operating Reserves Charges	Generation Credits Share of Total Operating Reserves Credits
Jan	50%	89%	50%	11%	11%	73%
Feb	48%	87%	52%	13%	15%	79%
Mar	47%	74%	53%	26%	14%	78%
Apr	43%	63%	57%	37%	14%	71%
May	45%	62%	55%	38%	13%	65%
Jun	45%	73%	55%	27%	18%	91%
Jul	42%	80%	58%	20%	17%	95%
Aug	43%	73%	57%	27%	17%	93%
Sep	45%	59%	55%	41%	18%	93%
Oct	44%	73%	56%	27%	18%	93%
Nov	44%	64%	56%	36%	16%	83%
Dec	49%	61%	51%	39%	15%	76%
Average	45%	71%	55%	29%	15%	83%

51 Balancing operating reserve charges in Table 3-31 include only those in the Generator category. Balancing operating reserve credits in Table 3-31 include Balancing Energy Market credits, Balancing Congestion credits and Lost Opportunity Cost credits. Categories are defined in Table 3-25.

Fuel Cost Increases and Operating Reserve Credits

Increases in fuel costs from 2004 to 2005 increased the cost of generation and thus increased operating reserve credits to generating units. Approximately $268 million of the $580 million in total balancing operating reserve credits resulted from increased fuel costs.

The monthly difference between total actual and fuel-cost-adjusted balancing operating reserve credits are shown in Figure 3-14.

Figure 3-14 - Fuel-cost-adjusted balancing operating reserve credits (All unit types): Calendar year 2005

The monthly difference between actual and fuel-cost-adjusted balancing operating reserve charges on a per MWh basis are shown in Table 3-32.

Table 3-32 - Fuel-cost-adjusted balancing operating reserve rate: Calendar year 2005

	Current Balancing Rate	Fuel-Cost-Adjusted Rate
Jan	1.72	1.53
Feb	1.04	0.84
Mar	0.81	0.45
Apr	0.73	0.47
May	0.90	0.81
Jun	2.80	1.93
Jul	4.32	3.11
Aug	3.82	1.95
Sep	4.78	1.29
Oct	6.70	2.27
Nov	2.62	1.45
Dec	2.72	0.88
Annual Average	2.75	1.42

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 reserves. 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 and arbitrarily small numbers of starts as well as submission of 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 must provide PJM operators better tools for defining and making optimal economic choices and must determine when the constraints on those choices effectively create market power opportunities when units are called on out of merit order and do not set price.

Top 10 Units

Balancing operating reserve credits have been paid to a disproportionately small number of units and companies since 2001. As Table 3-33 shows, in 2004 the top 10 units received 46.3 percent of total operating reserve payments and 27.7 percent of total operating reserve credits in 2005. In 2005, less than 1 percent of the units received 27.7 percent of total operating reserve credits. This decrease in the share of the top 10 units is largely a result of the fact that the number of units nearly doubled from the beginning of 2004 through the end of 2005. In 2004 the top 10 units were owned by three companies and in 2005 the top 10 were owned by four companies. In 2004 the top generator received 20 percent of the total operating reserves paid and in 2005 the top generator received 15 percent of the total operating reserves.

Table 3-33 - Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2005

	Percent
2001	46.7%
2002	32.0%
2003	39.3%
2004	46.3%
2005	27.7%

Markup

Unit Markups - 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.[52] As Table 3-34 shows, the markup for the top 10 units averaged 75.4 percent in 2005, a substantial increase over prior years. The markup for the top 10 units is a weighted average, where the weights are generator output when operating reserves are paid. The increased markup in 2005 resulted from a higher unit-specific markups combined with increased hours during which PJM dispatched units with high markups out of merit order.

The generation owner with the largest share of top 10 credits received 53 percent of operating reserve credits paid to the top 10 units and had a weighted-average markup of 55.4 percent in 2005. The next generation owner received 22 percent of operating reserve payments made to the top 10 units and had a weighted-average markup of 235.0 percent and the third generation owner received 20 percent of operating reserve payments made to the top 10 units and had a weighted-average markup of 0.0 percent in 2005.

52 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as outlined in PJM Manual M-15, "Cost Development Guidelines," Revision 5 (August 18, 2005).

For each year 2001 to 2005, the top 10 units receiving operating reserve credits were either conventional steam or CC technology generation, as shown in Table 3-34.

Half of the top 10 units are exempt from offer capping. Of all 9,540 hours when the top 10 units operated in real time and received balancing operating reserve credits in the Energy Market, only about 0.5 percent were offer-capped.

Table 3-34 - Top 10 operating reserve revenue units' markup: Calendar years 2001 to 2005

	Top Units' Markup	Steam Percent of Top 10	Steam Markup	Combined Cycle Percent of Top 10	Combined Cycle Markup
2001	2.9%	60%	2.2%	40%	7.4%
2002	11.3%	54%	8.0%	46%	20.4%
2003	16.9%	50%	19.4%	50%	11.3%
2004	3.0%	12%	0.1%	88%	4.9%
2005	75.4%	20%	52.9%	80%	81.7%

Unit Markups - All Units

Table 3-35 shows the simple average markup for generators exempt[53] from offer capping, for generators not exempt from offer capping and for all generators, when balancing operating reserves were paid.[54] The simple average markup for exempt CC and CT units is about 25 percentage points higher than for non-exempt units. The simple average markup for exempt diesel units is about 5 percentage points lower than for non-exempt diesel units. The associated maximum markups exceeded the average levels by a substantial amount; the maximum markup for an exempt unit was in excess of 650 percent.

Table 3-35 - Simple average generator markup: Calendar year 2005

Unit Class	Exempt	Non-Exempt	All Units
All Units	23.7%	8.2%	10.5%
CC	22.2%	(1.8%)	10.3%
CT	27.3%	2.5%	6.0%
Diesel	(4.1%)	0.8%	0.1%
Steam	NA	23.8%	23.8%

53 Generator exempt status is determined per 112 FERC ¶ 61,031 (2005). See also PJM Interconnection, L.L.C., Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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

Impact of Markups by Exempt Units

Table 3-36 compares total balancing operating reserve rate[55] 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 45 exempt units that received balancing operating reserve credits in 2005. The most significant difference between actual total credits and adjusted credits occurred during the July through October period when the balancing operating reserve rate was the highest of the year. The cumulative current total balancing operating reserve credit would have been lower by about $94 million in 2005 if exempt units were subject to offer capping and if the units would have been subject to offer-capping rules at the times they were paid operating reserve credits. If exempt units that received balancing operating reserves for generation were subject to offer capping and if the units would have been subject to offer-capping rules at the times they were paid operating reserve credits, then the balancing operating reserve rate would have been, on average, 15 percent lower than it was in 2005.[56]

Table 3-36 - Balancing operating reserve rate for exempt units (Actual and markup-adjusted): Calendar year 2005

	Current Rate	Markup-Adjusted Rate
Jan	1.72	1.33
Feb	1.04	0.88
Mar	0.81	0.65
Apr	0.73	0.67
May	0.90	0.79
Jun	2.80	2.69
Jul	4.32	3.15
Aug	3.82	3.11
Sep	4.78	4.31
Oct	6.70	5.52
Nov	2.62	2.30
Dec	2.72	2.53
Annual Average	2.75	2.33

55 Total balancing operating reserve credits do not take into account manual adjustments made after the billing period by PJM market settlement procedures.
56 The fuel-cost impact and the markup impact are not additive, but show separately the sensitivity of operating reserve charges to each factor.

Unit Operating Parameters

Operating reserve payments 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.

While a complete analysis of the impact of restrictive operating parameters on operating reserve credits has not been completed, preliminary analysis indicates that the submission of such parameters does increase operating reserve credits paid to some units.

SECTION 4 – INTERCHANGE TRANSACTIONS

The integration of two additional service territories into the PJM regional transmission organization (RTO) in 2005 significantly expanded PJM's geographic footprint and brought modest changes to its external interfaces. These interfaces are the seams between PJM and other regions. 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.

During the last two calendar years, PJM has 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. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[1]

- **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,[2] and the Allegheny Power Company (AP) Control Zone.[3]
- **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).[4]
- **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.

1 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

2 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

3 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 the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

4 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).

Overview

Interchange Transaction Activity

Aggregate Imports and Exports

- **Phase 4.** During the four months ended April 30, 2005, PJM, including the DLCO Control Zone, was a net exporter of power, with monthly net interchange averaging -1.2 million MWh.[5] Gross monthly import volumes averaged 3.7 million MWh while gross monthly exports averaged 4.9 million MWh.

- **Phase 5.** During the remaining eight months ended December 31, 2005, PJM, including the Dominion Control Zone, continued to be a net exporter of power. Monthly average net interchange was -1.5 million MWh. Gross monthly import volumes averaged 2.7 million MWh while gross monthly exports averaged 4.2 million MWh.

Interface Imports and Exports[6]

- **Phase 4.** During Phase 4, the two largest net exporting interfaces totaled 36 percent of the total net exporting volume: Michigan Electric Coordinated System (PJM/MECS) at 19 percent and PJM/New York Independent System Operator interface (PJM/NYIS) with 17 percent. Ninety-three percent of the net import volume was carried on three interfaces: PJM/Ohio Valley Electric Corporation (PJM/OVEC) carried 39 percent, PJM/Illinois Power (PJM/IP) carried 38 percent and PJM/Duke Energy Corp. (PJM/DUK) carried 16 percent of the volume.

- **Phase 5.** During Phase 5, the two largest net exporting interfaces totaled 51 percent of the total net exporting volume: Tennessee Valley Authority (PJM/TVA) with 29 percent and MidAmerican Electric Company (PJM/MEC) at 22 percent. Ninety-two percent of the net import volume was carried on three interfaces: PJM/OVEC carried 57 percent, PJM/IP carried 22 percent and FirstEnergy Corp. (PJM/FE) carried 13 percent of the volume.

Modified Interfaces and Pricing Points

- **Removal of Interfaces.** Integration of the DLCO Control Zone into PJM on January 1, 2005, resulted in the removal of the PJM/DLCO interface. The subsequent integration of the Dominion Control Zone on May 1, 2005, resulted in the removal of the PJM/VAP interface.

- **Pricing Point Changes.** On January 1, 2005, the DLCO pricing point was eliminated as a result of the DLCO integration. On April 1, 2005, the MISO pricing point was created as a result of the Midwest ISO's introduction of markets. On May 1, 2005, the Southeast pricing point was modified to account for the integration of the Dominion Control Zone.

5 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.

6 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

Existing and Proposed Operating Agreements with Bordering Areas

- **Midwest ISO.** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (JOA)[7] entered its second phase of implementation including market-to-market activity and coordinated market-based congestion management within and between both markets.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[8] The Joint Reliability Coordination Agreement (JRCA), executed on April 22, 2005, provides for the active management of seams among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The Agreement provides for comprehensive reliability management and congestion relief among the three regions.

- **PJM and Progress Energy Carolinas, Inc. (PEC) Joint Operating Agreement (JOA).**[9] An operating agreement between PJM and PEC, approved by the FERC on September 9, 2005, with an effective date of July 30, 2005, provides for market-to-non market coordination.

PJM TLRs

- The number of transmission loading relief procedures (TLRs) issued by PJM declined after the integration of the AEP and DAY Control Zones. The integration meant that PJM could redispatch generating units to relieve constraints on facilities in the newly integrated areas where PJM had previously relied on TLRs for constraint control. The result was a drop in the number of TLRs called by PJM, particularly in the AEP Control Zone.

Actual Versus Scheduled Power 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. Loop flows have negative consequences because they constitute unscheduled use of PJM's transmission system, affect real-time system operations and affect the revenue adequacy of Financial Transmission Rights (FTR) because loop flows do not pay congestion costs. Although PJM's total scheduled and actual flows differed by about 4 percent in 2005, there were significant differences for individual interfaces. PJM's method of defining pricing points is designed to provide price signals consistent with the actual power flows and thus to minimize the incentive to create loop flow.

7 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (JOA) (December 31, 2003) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (2.73 MB).

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

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

Interchange Issues

- **PJM and Midwest ISO Transaction Issues.** During 2005, the relationship between prices at the PJM/MISO interface and at the MISO/PJM interface appeared to reflect economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.

- **PJM and New York ISO Transaction Issues.** During 2005, the relationship between prices at the PJM/NYIS interface and at the New York Independent System Operator (NYISO) PJM proxy bus appeared to reflect economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the NYISO. As in 2004, however, both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

- **Consolidated Edison and PSEG Wheeling Contracts.** Two contracts governing wheeling of up to 1,000 MW of power through PJM into New York City were the subject of a November 2001 complaint to the FERC. The FERC issued an order on May 18, 2005, defining a protocol to resolve this issue which was implemented in July 2005. Based on early performance of the protocol, Consolidated Edison has formally asked the FERC to require PJM and NYISO to improve operations under the protocol to increase delivery performance, and PJM and NYISO are working to resolve these issues.

- **Ramp and Transmission Reservations.** PJM should consider development of rules that limit a market participant's ability to reserve more ramp than is actually either needed or used in order to facilitate the efficient use of limited ramp capability.

Conclusion

The PJM Market Monitoring Unit (MMU) analyzed the transactions between PJM and neighboring control areas for 2005 including evolving transactions patterns, economics and issues. The location of PJM transactions with external areas has changed significantly as a result of the substantial expansion of the PJM footprint over the last two years. New interfaces dominate export and import activity. In contrast to the first five years of PJM operations, PJM continued the recent pattern of being a net exporter of energy. While exports and imports have historically primarily cleared in the Real-Time Energy Market, transactions in the Day-Ahead Energy Market continued to grow in volume. PJM has entered into a number of agreements with neighboring control areas that govern reliability and economic coordination. As interactions with external areas are increasingly governed by economic redispatch, interface prices and volumes reflect supply and demand conditions and the number of TLRs has declined. PJM continues to face significant loop flows with substantial impacts on PJM for reasons that are not yet well understood. A cooperative analysis with the Midwest ISO would contribute to the understanding that is required before a solution can be designed. The Consolidated Edison/PSEG wheeling contracts are now managed under a FERC-approved protocol that has improved operations and additional improvements are being made. The allocation and management of ramp, the capability to import into or export from PJM, continue to create potential issues and improvements are also required in this area.

Interchange Transaction Activity

Aggregate Imports and Exports (by Phase)

With the integration of the ComEd Control Area and reinforced by the integration of the AEP and DAY Control Zones in Phases 2 and 3, PJM became a systematic net exporter of power for the first time since the introduction of markets. PJM continued to be a net exporter of power in both Phases 4 and 5. (See Figure 4-1 and Figure 4-3.)

Phase 4

During Phase 4, PJM was a net exporter of energy for each month. Total net interchange of -5.0 million MWh during January through April 2005 compares to a net interchange of 7.4 million MWh for the comparable period in 2004. (Note the sign change from the previous year's comparable period.) For these four-month periods, the peak months for net interchange were January in 2005 (-1.8 million MWh) and January in 2004 (2.3 million MWh).

Phase 5

During Phase 5, PJM continued to be a net exporter of energy in each month. Monthly exports averaged 4.2 million MWh and monthly imports averaged 2.7 million MWh for an average monthly net interchange of -1.5 million MWh.

2005 Trends

While PJM market participants have historically imported and exported energy primarily in the Real-Time Energy Market (See Figure 4-1.), that pattern began to change in 2004 and the volume of transactions in the Day-Ahead Energy Market continued to grow in 2005. Although day-ahead volume continues to be smaller by comparison, the difference is decreasing. (See Figure 4-2.) In 2005, import transactions in the Day-Ahead Energy Market were 50 percent of the import volume (27 percent in 2004) in the Real-Time Market while export transactions in the Day-Ahead Market were 50 percent of the gross export volume (39 percent in 2004) in the Real-Time Market.

Import transactions in the Day-Ahead Market were highest at the PJM/OVEC and PJM/FE interfaces during both phases of 2005. In Phase 4, PJM/OVEC accounted for 45 percent and PJM/FE accounted for 27 percent of the average hourly volume. In Phase 5, they were 49 percent and 21 percent, respectively. Export transactions in the Day-Ahead Market were highest at the PJM/MEC and PJM/NYIS interfaces in both phases of 2005. In Phase 4, PJM/MEC accounted for 15 percent and PJM/NYIS accounted for 12 percent of the average hourly volume. In Phase 5, they were 18 percent and 20 percent, respectively. Transactions in the Day-Ahead Market create a financial obligation to deliver in the Real-Time Market and if the obligation is not fulfilled in the Real-Time Market, operating reserve charges will also be incurred.

Figure 4-1 - PJM real-time imports and exports: Calendar year 2005

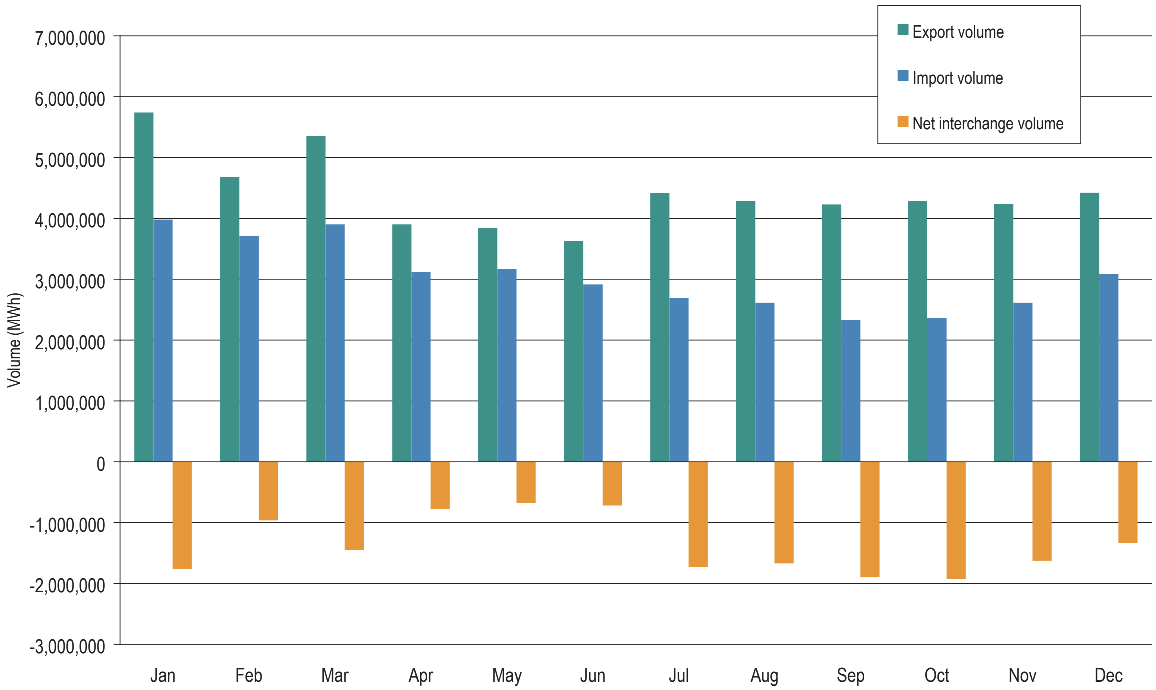


Figure 4-2 - Total day-ahead import and export volume: Calendar year 2005

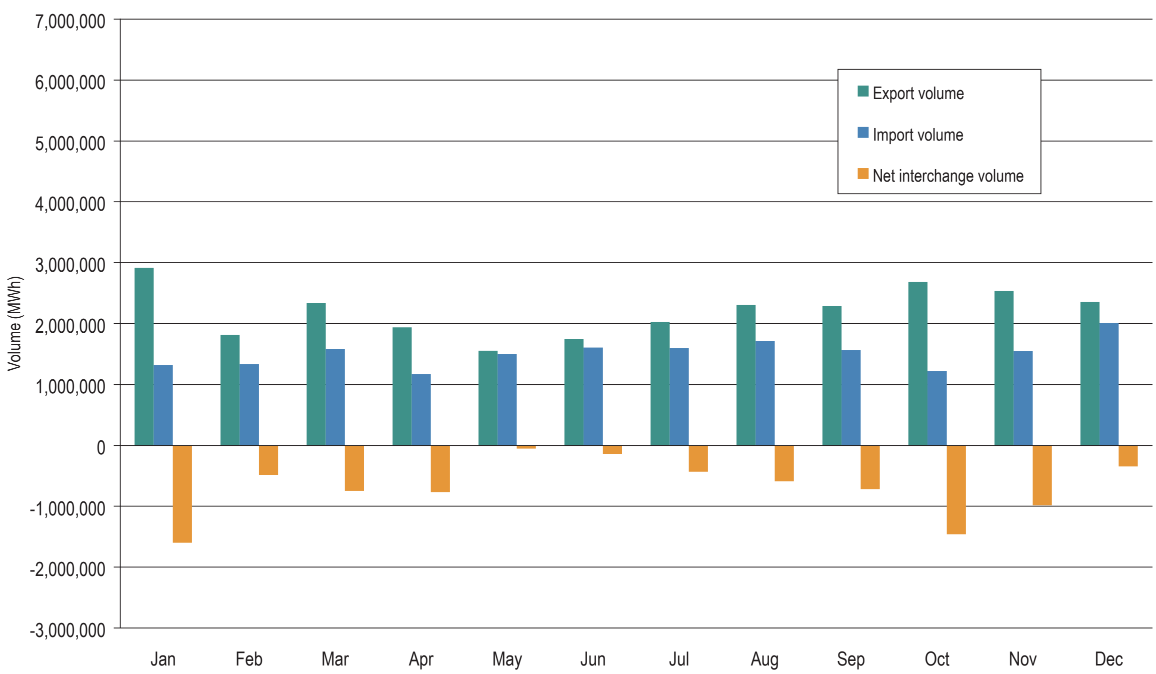
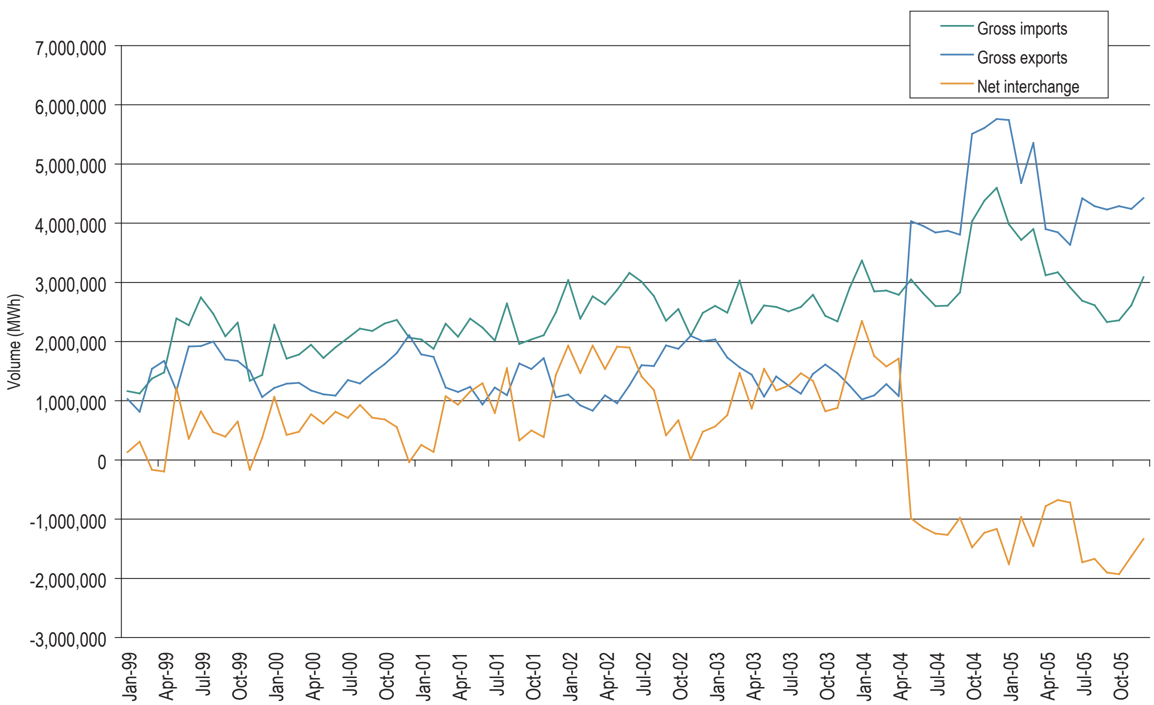


Figure 4-3 shows import and export volume for PJM from 1999 through 2005. Gross exports exhibited a particularly sharp increase in Phase 2 that was not matched by imports while the increase in gross exports and imports in Phase 3 was more balanced. During Phases 4 and 5, gross imports and exports generally declined while net interchange fluctuated with no clear trend.

Figure 4-3 - PJM import and export transaction volume history: Calendar years 1999 to 2005



Interface Imports and Exports (by Phase)

Total imports and exports are comprised of flows at each PJM interface. Net interchange is shown by interface for each phase of 2005 in Table 4-1 while gross imports and exports are shown by interface for each phase of 2005 in Table 4-2 and Table 4-3.

Phase 4

There were net exports at 15 of PJM's 22 interfaces in Phase 4. Two exporting interfaces accounted for 36 percent of the total net exports, PJM/MECS at 19 percent and PJM/NYIS at 17 percent. Gross exports at four interfaces made up half of gross exports, PJM/NYIS at 16 percent, PJM/MECS at 13 percent, PJM/Cinergy Corporation (CIN) at 11 percent and PJM/MEC at 10 percent.

There were net imports at the remaining seven of PJM's interfaces in Phase 4. Three interfaces accounted for 93 percent of the net import volume, PJM/OVEC with 39 percent, PJM/IP with 38 percent and PJM/DUK with 16 percent of the volume. Gross imports at three interfaces accounted for more than half (54 percent) of gross imports, PJM/IP at 21 percent, PJM/OVEC at 20 percent and PJM/CIN at 13 percent.

Phase 5

There were net exports at 16 of PJM's 21 interfaces in Phase 5. Two exporting interfaces accounted for 51 percent of the total net exports, PJM/TVA with 29 percent and PJM/MEC at 22 percent. PJM/NYIS, which had been PJM's largest net exporting interface prior to the integrations, was the third largest in Phase 5 with 16 percent of the net exporting volume. Gross exports at three interfaces made up 58 percent of gross exports, PJM/NYIS at 21 percent, PJM/TVA at 21 percent and PJM/MEC at 16 percent.

There were net imports at the remaining five of PJM's interfaces in Phase 4. Three interfaces accounted for 92 percent of the net import volume, PJM/OVEC with 57 percent, PJM/IP with 22 percent and PJM/FE with 13 percent of the volume. Gross imports at three interfaces accounted for 60 percent of gross imports, PJM/OVEC at 32 percent, PJM/FE at 14 percent and PJM/NYIS at 14 percent.

Table 4-1 - Net interchange volume by interface (MWh x 1,000): Calendar year 2005

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
FE	(343.1)	71.5	5.7	178.2	344.8	122.6	138.2	179.0	174.7	210.5	221.7	205.8	1,509.6
NYIS	(628.4)	(441.5)	(569.2)	(502.1)	(715.4)	(441.4)	(443.2)	(348.0)	(452.3)	(625.9)	(389.7)	(342.9)	(5,900.0)
VAP	(237.5)	(160.4)	(188.2)	(282.7)	NA	NA	NA	NA	NA	NA	NA	NA	(868.8)
ALTE	(112.5)	(145.3)	(169.8)	(106.6)	(114.2)	(141.8)	(166.6)	(109.7)	(105.8)	(109.2)	(106.2)	(109.1)	(1,496.8)
ALTW	(132.2)	(112.8)	(242.3)	(223.2)	(140.8)	(175.5)	(154.7)	(118.0)	(116.6)	(117.4)	(138.3)	(130.8)	(1,802.6)
AMRN	(24.6)	64.0	(3.4)	(173.3)	(91.9)	(185.2)	(179.5)	(168.8)	(171.6)	(188.9)	(161.0)	(126.5)	(1,410.7)
CILC	1.9	7.1	7.4	0.0	0.5	0.9	(1.2)	0.0	0.7	(4.9)	(33.0)	(18.1)	(38.7)
IP	1,019.0	727.5	706.6	394.5	366.8	317.4	319.4	316.1	310.8	328.7	328.8	333.6	5,469.2
MEC	(539.5)	(445.6)	(306.2)	(517.6)	(642.9)	(456.4)	(571.8)	(632.4)	(700.4)	(768.0)	(559.3)	(774.1)	(6,914.2)
NIPS	22.0	41.2	132.7	(4.3)	(0.1)	(0.8)	(0.2)	(0.3)	(15.5)	(0.3)	(1.1)	(0.1)	173.2
WEC	(415.6)	(404.1)	(556.1)	(93.8)	(84.5)	(103.6)	(126.9)	(129.9)	(124.7)	(129.2)	(112.5)	(99.0)	(2,379.9)
MECS	(952.1)	(652.8)	(677.1)	(118.7)	(54.3)	(118.2)	(138.5)	(126.2)	(155.0)	(92.3)	(89.1)	(92.1)	(3,266.4)
CPLE	(161.7)	(165.0)	(123.3)	(174.2)	(91.4)	(150.9)	(216.6)	(209.7)	(203.1)	(71.2)	127.9	148.8	(1,290.4)
CPLW	(72.2)	(67.1)	(72.2)	(71.3)	(50.5)	(71.1)	(73.3)	(67.8)	(70.1)	(74.7)	(20.7)	(73.7)	(784.7)
CIN	(195.0)	(103.7)	(142.5)	219.3	332.7	8.1	(286.9)	(359.6)	(316.0)	(329.6)	(176.6)	(36.3)	(1,386.1)
DUK	250.8	229.3	374.2	335.4	5.5	290.7	207.4	146.9	(117.0)	10.4	(56.1)	143.2	1,820.7
EKPC	(7.3)	(3.3)	(15.3)	(28.6)	(27.6)	14.2	(6.1)	(16.9)	(7.9)	(37.5)	(72.3)	(121.9)	(330.5)
IPL	(14.2)	1.8	4.7	(0.3)	(0.3)	0.2	0.0	0.0	(0.2)	(0.2)	(0.7)	(1.3)	(10.5)
LGEE	71.4	67.1	84.0	36.3	46.3	44.9	48.6	33.9	50.5	(1.1)	33.7	(0.1)	515.5
OVEC	748.8	703.6	743.3	707.6	923.9	859.4	827.1	843.8	831.5	818.8	842.8	849.1	9,699.7
TVA	(38.6)	(176.3)	(447.9)	(356.2)	(681.7)	(531.2)	(904.9)	(904.4)	(711.4)	(730.0)	(1,266.0)	(1,089.2)	(7,837.8)
CWLP	0.0	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	(18.7)	0.0	0.0	(18.0)
Total	(1,760.6)	(964.5)	(1,454.5)	(781.6)	(675.1)	(717.7)	(1,729.7)	(1,672.0)	(1,899.4)	(1,930.7)	(1,627.7)	(1,334.7)	(16,548.2)

Table 4-2 - Gross import volume by interface (MWh x 1,000): Calendar year 2005

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
FE	334.0	459.1	388.5	422.6	542.5	346.6	337.3	335.9	288.1	342.7	396.1	400.0	4,593.4
NYIS	203.7	231.1	282.2	283.2	219.1	396.6	396.4	477.1	428.2	336.4	371.5	465.8	4,091.3
VAP	28.3	24.6	33.4	16.5	NA	NA	NA	NA	NA	NA	NA	NA	102.8
ALTE	0.1	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.7	1.6	5.0
ALTW	5.5	6.1	9.9	1.4	1.9	1.0	0.0	0.1	0.3	0.2	0.0	0.9	27.3
AMRN	201.8	238.6	138.5	124.3	133.6	59.6	63.1	34.3	40.3	40.8	36.2	56.5	1,167.6
CILC	6.7	8.9	9.6	0.2	0.5	1.0	0.2	0.0	0.7	0.0	1.3	6.4	35.5
IP	1,093.2	783.8	744.9	443.0	389.2	357.3	354.2	338.0	323.9	328.9	328.8	333.8	5,819.0
MEC	42.7	37.5	19.7	15.9	9.1	13.3	10.0	7.0	8.5	12.6	34.6	35.5	246.4
NIPS	44.0	75.4	142.6	0.0	0.8	0.2	0.0	0.0	0.1	0.0	0.0	0.0	263.1
WEC	2.0	0.2	1.5	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.0	0.0	4.0
MECS	30.8	40.9	93.1	20.4	57.3	24.9	39.4	17.7	4.9	24.7	23.9	22.9	400.9
CPLE	136.2	125.9	178.3	84.5	42.0	56.7	59.5	66.4	39.3	115.8	227.3	397.7	1,529.6
CPLW	0.0	0.0	4.2	0.0	0.0	0.0	0.4	0.7	0.0	0.0	0.0	0.0	5.3
CIN	472.5	483.9	486.1	454.4	511.9	298.4	132.0	131.6	108.9	103.4	123.0	203.2	3,509.3
DUK	435.4	389.6	495.0	471.5	249.2	398.0	387.9	290.1	179.0	209.3	186.9	280.3	3,972.2
EKPC	9.1	13.9	15.7	16.4	30.2	33.8	6.9	1.4	6.3	0.7	1.3	0.0	135.7
IPL	7.5	6.6	8.6	0.2	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	23.2
LGEE	74.1	73.2	89.5	42.4	49.6	47.6	49.4	49.1	51.2	0.1	34.9	0.0	561.1
OVEC	759.0	711.4	749.1	715.7	932.8	880.3	849.7	865.6	849.6	839.2	843.2	861.5	9,857.1
TVA	94.7	4.5	8.9	7.0	0.4	0.5	4.5	0.7	0.3	3.6	1.6	22.5	149.2
CWLP	0.0	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
Total	3,981.3	3,715.5	3,900.2	3,119.6	3,170.1	2,916.2	2,690.9	2,615.7	2,329.6	2,358.7	2,613.3	3,088.6	36,499.7

Table 4-3 - Gross export volume by interface (MWh x 1,000): Calendar year 2005

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
FE	677.1	387.6	382.8	244.4	197.7	224.0	199.1	156.9	113.4	132.2	174.4	194.2	3,083.8
NYIS	832.1	672.6	851.4	785.3	934.5	838.0	839.6	825.1	880.5	962.3	761.2	808.7	9,991.3
VAP	265.8	185.0	221.6	299.2	NA	NA	NA	NA	NA	NA	NA	NA	971.6
ALTE	112.6	145.3	170.3	106.6	114.2	141.8	166.6	109.7	105.8	109.3	108.9	110.7	1,501.8
ALTW	137.7	118.9	252.2	224.6	142.7	176.5	154.7	118.1	116.9	117.6	138.3	131.7	1,829.9
AMRN	226.4	174.6	141.9	297.6	225.5	244.8	242.6	203.1	211.9	229.7	197.2	183.0	2,578.3
CILC	4.8	1.8	2.2	0.2	0.0	0.1	1.4	0.0	0.0	4.9	34.3	24.5	74.2
IP	74.2	56.3	38.3	48.5	22.4	39.9	34.8	21.9	13.1	0.2	0.0	0.2	349.8
MEC	582.2	483.1	325.9	533.5	652.0	469.7	581.8	639.4	708.9	780.6	593.9	809.6	7,160.6
NIPS	22.0	34.2	9.9	4.3	0.9	1.0	0.2	0.3	15.6	0.3	1.1	0.1	89.9
WEC	417.6	404.3	557.6	93.8	84.5	103.7	126.9	129.9	124.7	129.4	112.5	99.0	2,383.9
MECS	982.9	693.7	770.2	139.1	111.6	143.1	177.9	143.9	159.9	117.0	113.0	115.0	3,667.3
CPLE	297.9	290.9	301.6	258.7	133.4	207.6	276.1	276.1	242.4	187.0	99.4	248.9	2,820.0
CPLW	72.2	67.1	76.4	71.3	50.5	71.1	73.7	68.5	70.1	74.7	20.7	73.7	790.0
CIN	667.5	587.6	628.6	235.1	179.2	290.3	418.9	491.2	424.9	433.0	299.6	239.5	4,895.4
DUK	184.6	160.3	120.8	136.1	243.7	107.3	180.5	143.2	296.0	198.9	243.0	137.1	2,151.5
EKPC	16.4	17.2	31.0	45.0	57.8	19.6	13.0	18.3	14.2	38.2	73.6	121.9	466.2
IPL	21.7	4.8	3.9	0.5	0.3	0.1	0.0	0.0	0.2	0.2	0.7	1.3	33.7
LGEE	2.7	6.1	5.5	6.1	3.3	2.7	0.8	15.2	0.7	1.2	1.2	0.1	45.6
OVEC	10.2	7.8	5.8	8.1	8.9	20.9	22.6	21.8	18.1	20.4	0.4	12.4	157.4
TVA	133.3	180.8	456.8	363.2	682.1	531.7	909.4	905.1	711.7	733.6	1,267.6	1,111.7	7,987.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.7	0.0	0.0	18.7
Total	5,741.9	4,680.0	5,354.7	3,901.2	3,845.2	3,633.9	4,420.6	4,287.7	4,229.0	4,289.4	4,241.0	4,423.3	53,047.9

2005 Trends

With the integrations of the DLCO and Dominion Control Zones, PJM continued to be a net exporter of power through both integrations. The shift from a net importer to a net exporter of power began with the integration of ComEd in Phase 2 of 2004 and continued through Phases 4 and 5 of 2005. The gross import and export volumes decreased in Phases 4 and 5.

Modified Interfaces and Pricing Points

During 2005, because of the Phase 4 and Phase 5 integrations, PJM retired the DLCO pricing point, the PJM/DLCO interface and the PJM/VAP interface and redefined the Southeast pricing point. When the Midwest ISO market became operational, PJM added the MISO pricing point.

Removal of Interfaces

PJM experienced two integrations in 2005, each of which changed the number of external interfaces. (See Table 4-4.) When the DLCO Control Zone became part of PJM in Phase 4, the external interfaces changed and the PJM/DLCO interface was retired.

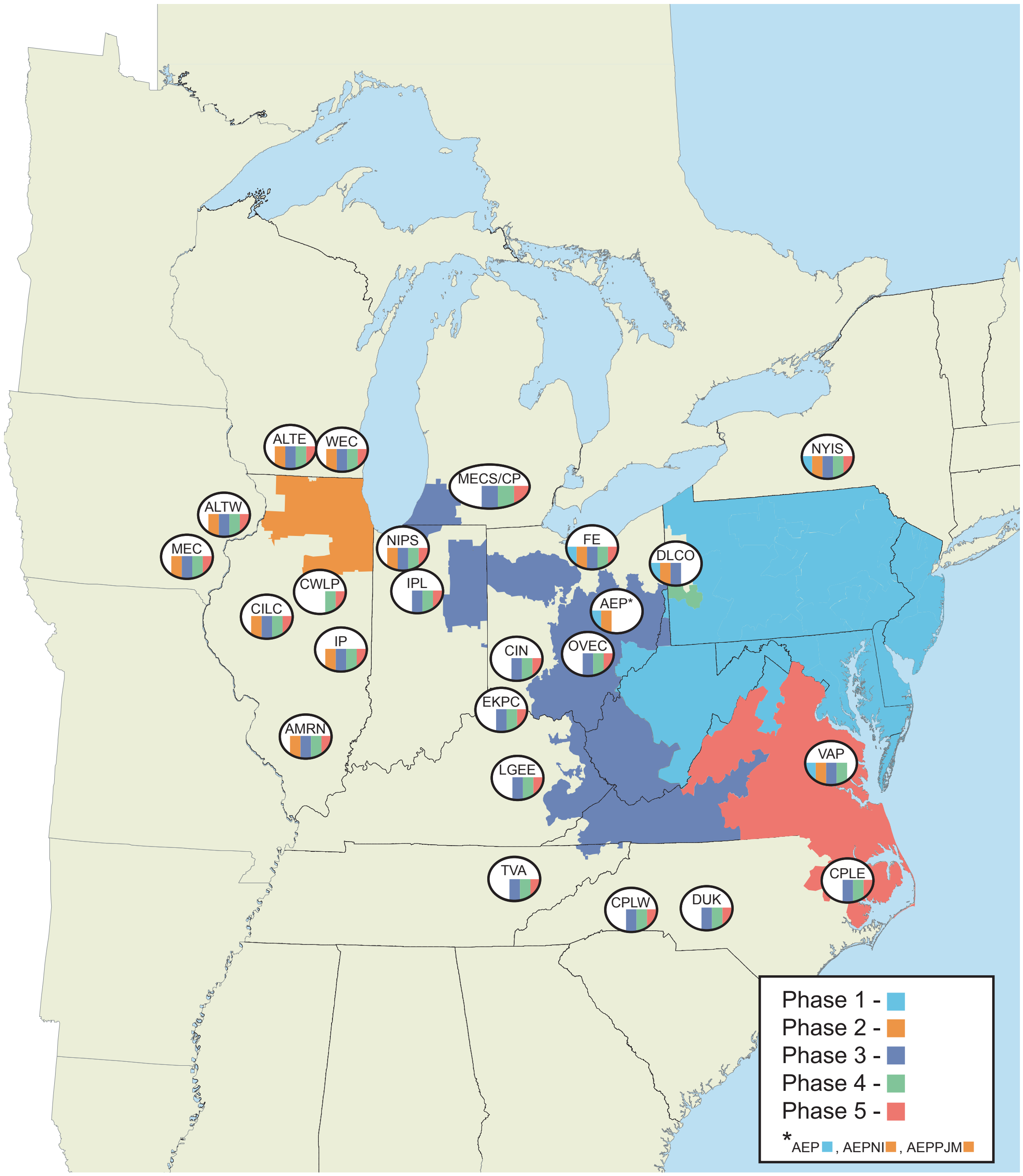
When the Dominion Control Zone became part of PJM in Phase 5, the boundaries shifted again. The number of external interfaces was reduced to 21 and the PJM/VAP interface was retired.

Table 4-4 - Active interfaces: Calendar year 2005

	Phase 4				Phase 5							
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DLCO												
FE	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
VAP	Active	Active	Active	Active								
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMRN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CILC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	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
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

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

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



Changes to 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.[10] 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.[11] 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.[12]

Before the DLCO and Dominion Control Zone integrations, the nine PJM interface pricing points had been: NYISO, MICHFE, DLCO, Northern Indiana Public Service Company (NIPSCO), Northwest, Southwest, Southeast, OVEC and the Ontario Independent Electricity System Operator (Ontario IESO).

Interface pricing points were retired, added and modified in 2005. In Phase 4 the DLCO pricing point was retired, reflecting the integration of the Duquesne Light Company control area. No new pricing point was required since all surrounding areas were already accounted for in existing pricing point definitions. On April 1, 2005, the Midwest ISO pricing point was added in response to startup of the Midwest ISO market. In Phase 5, the Southeast pricing point was modified to account for the integration of the Dominion Control Zone. Table 4-5 presents the interface pricing points used during 2005.

Table 4-5 - Active pricing points by interface: Calendar year 2005

	Phase 4				Phase 5							
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DLCO												
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
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
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

10 See Appendix D, “Interchange Transactions,” for a more detailed discussion of interface pricing.

11 See “LMP Aggregate Definitions” < http://www.pjm.com/markets/energy-market/downloads/20060103-aggregate-definitions.xls> (1.33 MB).

12 See Appendix D, “Interchange Transactions,” for a more complete discussion of the development of pricing points.

Interchange Transaction Topics

During 2005, four broad topics emerged involving interchange transactions. PJM developed and implemented operating agreements with bordering areas, PJM TLRs were partially displaced by economic dispatch, PJM faced significant loop flow issues and PJM addressed a range of issues emerging from existing interfaces, contracts and technical issues.

Existing and Proposed 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 executed operating agreement with Progress Energy Carolinas, Inc. and a reliability agreement with TVA.

The PJM/ Midwest ISO Joint Operating Agreement (JOA)

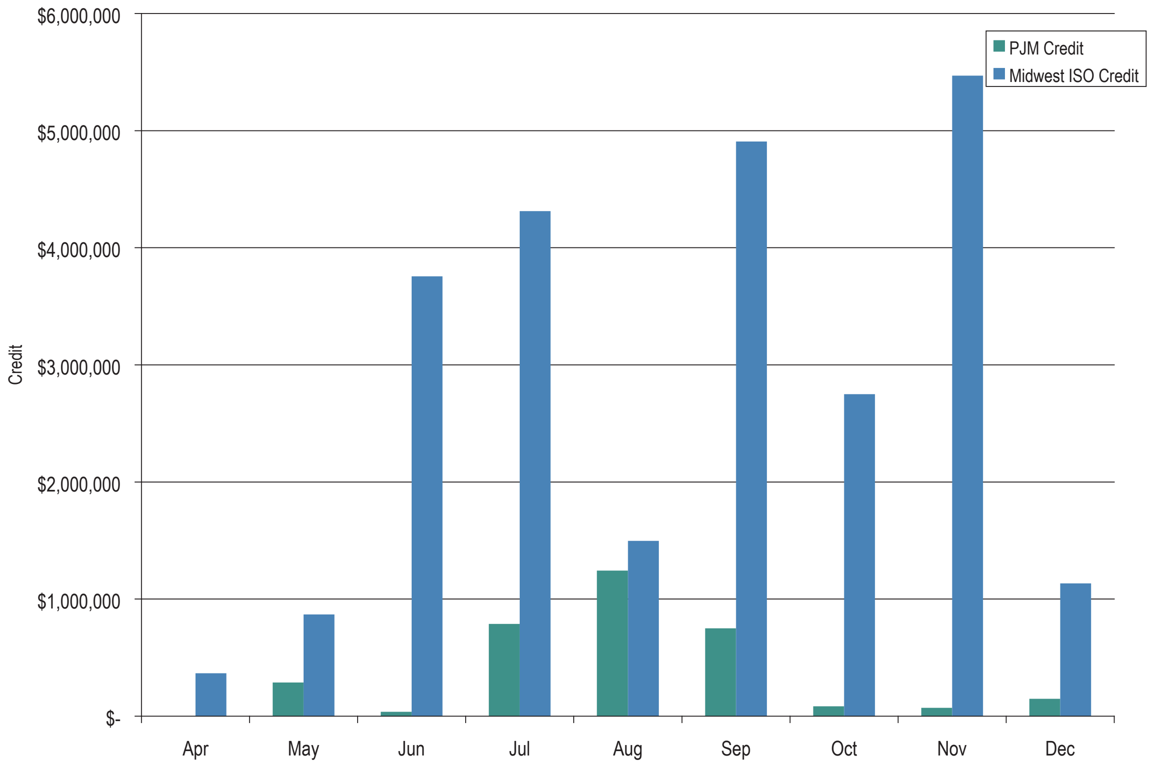
On April 1, 2005, the Midwest ISO market became operational. This triggered the second, market-to-market phase, of the JOA.

The JOA includes features designed to improve reliability, including provisions governing the sharing of operating information, system models, planning data, outage coordination and emergency planning. The second phase added jointly coordinated, least cost redispatch for congestion control between the two markets.

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 computation of the MISO/PJM pricing point.

Since April, 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 in the April through December period were the result of redispatch by Midwest ISO to relieve congestion on the Eau Clair – Arpin 345 kV line that was the result of PJM dispatch to meet load. Total PJM payments to Midwest ISO were $7.6 million. The largest payments from Midwest ISO to PJM in the April through December period were the result of redispatch by PJM to relieve congestion on the Mt. Storm-Pruntytown 500 kV line that was the result of Midwest ISO dispatch to meet load. Total Midwest ISO payments to PJM were $1.5 million.

Figure 4-5 - Credits for coordinated congestion management: April through December 2005



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 parties share critical operating information, system models and extensive planning data to ensure that all have the best information possible in their day-to-day operations. Information-sharing 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. When redispatch by the market-based entity is able to aid congestion management between market and non market systems, the overall cost of the congestion reduction is lower. However, unlike the PJM-Midwest ISO market-to-market agreement, there are no payments among the parties for market-to-non market coordination.

The three organizations also 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. Planning will be conducted in a manner consistent with Midwest ISO and PJM's respective tariffs and the laws and rules pertaining to TVA's status as a regional, non-FERC jurisdictional entity.

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 JOA provides for the management of congestion and key points of the agreement include the parties establishing an operating committee, sharing operating data, using coordinated flowgates to address congestion, coordinating scheduled outages, operating jointly during emergencies, coordinating transmission planning studies, maintaining joint checkout procedures and coordinating voltage and reactive power.

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 are expected to be completed during the first half of 2006.

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 2005, after the integrations of the DLCO and Dominion Control Zones, than had been called in 2004. Total PJM TLRs declined by 24 percent, from 429 during 2004 to 326 in 2005 (See Figure 4-6.) while, as a result of the expanded footprint, the number of unique flowgates for which PJM declared TLRs increased from 55 different flowgates during 2004 to 69 different flowgates in 2005. (See Figure 4-7 for monthly data.) Of the 326 TLRs called by PJM in 2005, four facilities comprised 57 percent of the total. The four facilities were:

- **Wylie Ridge Transformers.** This is 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. (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 (50 TLRs in 2005);

- **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 and loop flows are the main reasons for TLRs on this line (39 TLRs in 2005); and

- **Cloverdale-Lexington 500 kV Line for Loss of Pruntytown-Mount Storm 500 kV Line.** The Cloverdale-Lexington line is in southern Virginia and the Pruntytown-Mount Storm line runs between West Virginia and Maryland just south of Pennsylvania. Unit operation at the Bath County pumped storage facility, when in the pumping mode, aggravates this constraint. The problem is not easily controllable with redispatch because of lack of generation with the necessary impact (29 TLRs in 2005).

In 2005, the top three facilities for which PJM called TLRs were the same as in 2004 although their share of all TLRs declined. Wylie Ridge, Cloverdale-Lexington and Roseland-Cedar Grove accounted for 41 percent of PJM's TLRs in 2005 and 61 percent in 2004.

During June, an unusually large number of TLRs were called in the ComEd Control Zone, with 13 TLRs called on seven facilities. In most months, very few TLRs are called in the ComEd Control Zone. A combination of high loads in the ComEd Control Zone, outages on the King - Eau Claire line and on the Cherry Valley TR82 transformer, generator retirements in ComEd and the dispatching of new units in Wisconsin caused June's TLR increase.

Figure 4-6 - PJM and Midwest ISO TLR procedures: Calendar years 2004 and 2005

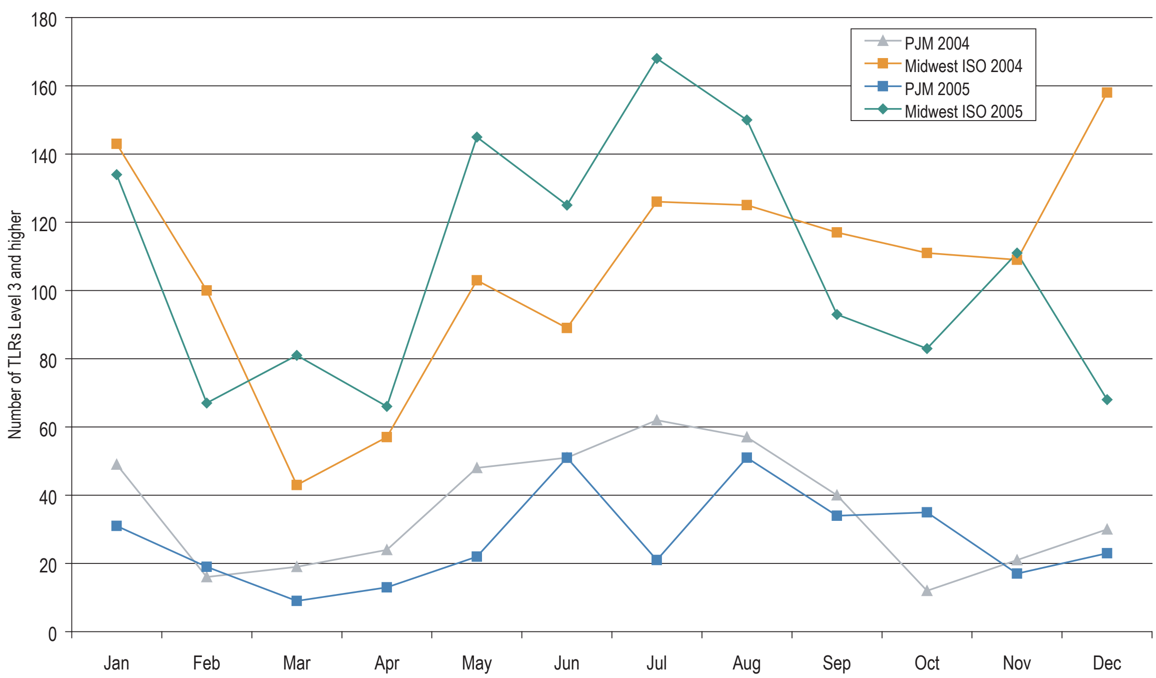
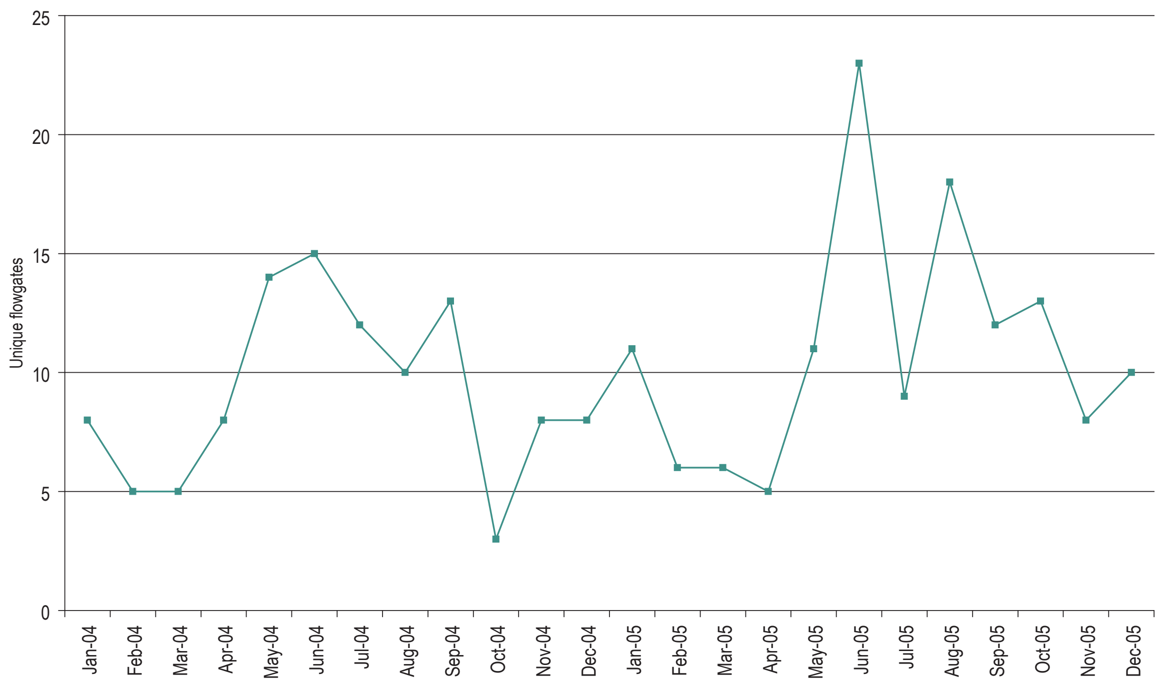


Figure 4-7 - Number of unique PJM flowgates: Calendar years 2004 to 2005



Actual Versus Scheduled Power Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled to flow 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 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 although actual, associated energy deliveries flow on the path of least resistance. 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 redispatch and TLR procedures.

The fact that total PJM net actual interface flows were only about 4 percent less than net scheduled interface flows on average for 2005 as a whole is not a useful measure of either net interchange or of loop flow. There were differences between net scheduled and actual interchange for both Phase 4 and Phase 5, although they were in opposite directions in each phase and, more importantly, there were significant differences between scheduled and actual flows for specific individual interfaces. (See Table 4-6.) PJM tries to balance overall actual and scheduled interchange, but does not attempt to maintain a balance between actual and scheduled interchange at individual interfaces.

During Phase 4, for PJM as a whole, net scheduled and actual interchange differed by approximately 6 percent. Actual system exports were 5.270 million MWh, in excess of the scheduled total exports of 4.961 million MWh by 0.309 million MWh. Flow balance varied at each individual interface. The PJM/TVA interface was the most imbalanced, with net actual imports of 1.486 exceeding scheduled exports of 1.019 by 2.505 million MWh or -246 percent, for an average of 870 MW during each hour of the period. At the PJM/MECS interface, net actual exports exceeded scheduled exports by 2.211 million MWh or 92 percent. At the PJM/IP interface, net scheduled imports exceeded actual imports by 1.903 million MWh or 67 percent. At the PJM/NYIS interface, net actual exports exceeded scheduled exports by 1.550 million MWh or 72 percent. At the PJM/ALTE interface, net actual exports exceeded scheduled exports by 1.481 million MWh or 277 percent.

During Phase 5, for PJM as a whole, net scheduled and actual interchange differed by approximately 9 percent. Actual system exports were 10.523 million MWh, less than the scheduled total of 11.571 million MWh by 1.048 million MWh. Flow balance varied at each individual interface. The PJM/MECS interface was the most imbalanced, with net actual exports exceeding scheduled exports by 7.974 million MWh or 924 percent, for an average of 1,356 MW during each hour. At the PJM/TVA interface, net actual imports of 0.212 exceeded scheduled exports of 6.804 by 7.016 million MWh or 103 percent. At the PJM/CPLE interface actual imports exceeded scheduled exports by 4.550 million MWh or 686 percent. At the PJM/CIN interface actual imports exceeded scheduled exports by 4.087 million MWh or 350 percent.

Table 4-6 - Net scheduled and actual PJM interface flows (MWh x 1,000): Calendar year 2005

	Actual	Net Scheduled	Difference (MW)	Difference
ALTE	(2,015)	(534)	(1,481)	277%
ALTW	(770)	(711)	(59)	8%
AMRN	288	(137)	425	(310%)
CILC	382	17	365	2147%
CIN	772	(222)	994	(448%)
CPLE	595	(624)	1,219	(195%)
CPLW	(453)	(283)	(170)	60%
CWLP	(105)	1	(106)	(10600%)
DUK	252	1,190	(938)	(79%)
EKPC	239	(55)	294	(535%)
FE	(827)	(87)	(740)	851%
IP	945	2,848	(1,903)	(67%)
IPL	1,104	(8)	1,112	(13900%)
LGEE	274	259	15	6%
MEC	(1,206)	(1,810)	604	(33%)
MECS	(4,612)	(2,401)	(2,211)	92%
NIPS	(1,049)	192	(1,241)	(646%)
NYIS	(3,693)	(2,143)	(1,550)	72%
OVEC	3,962	2,905	1,057	36%
TVA	1,486	(1,019)	2,505	(246%)
VAP	(394)	(869)	475	(55%)
WEC	(445)	(1,470)	1,025	(70%)
Phase 4 System	(5,270)	(4,961)	(309)	6%
ALTE	(4,265)	(959)	(3,306)	345%
ALTW	(1,905)	(1,089)	(816)	75%
AMRN	(962)	(1,273)	311	(24%)
CILC	268	(55)	323	(587%)
CIN	2,920	(1,167)	4,087	(350%)
CPLE	3,887	(663)	4,550	(686%)
CPLW	(1,311)	(500)	(811)	162%
CWLP	(425)	(19)	(406)	2137%
DUK	(1,505)	625	(2,130)	(341%)
EKPC	61	(276)	337	(122%)
FE	754	1,584	(830)	(52%)
IP	1,560	2,611	(1,051)	(40%)
IPL	2,159	(2)	2,161	(108050%)
LGEE	441	257	184	72%
MEC	(3,398)	(5,081)	1,683	(33%)
MECS	(8,837)	(863)	(7,974)	924%
NIPS	(710)	(18)	(692)	3844%
NYIS	(7,604)	(3,737)	(3,867)	103%
OVEC	8,046	6,766	1,280	19%
TVA	212	(6,804)	7,016	(103%)
WEC	91	(908)	999	(110%)
Phase 5 System	(10,523)	(11,571)	1,048	(9%)
2005 Total	(15,793)	(16,532)	739	(4%)

The PJM/MECS interface exhibited large imbalances between scheduled and actual power flows, particularly during the overnight off-peak hours. (See Figure 4-8 and Figure 4-9.) Generally, the PJM/MECS interface is an exporting interface meaning that power flows from PJM to MECS. The actual exports exceed the scheduled exports at that interface by an average of 1,203 MW for those off-peak hours.

Figure 4-8 - PJM/MECS interface average actual minus scheduled volume: Phase 4

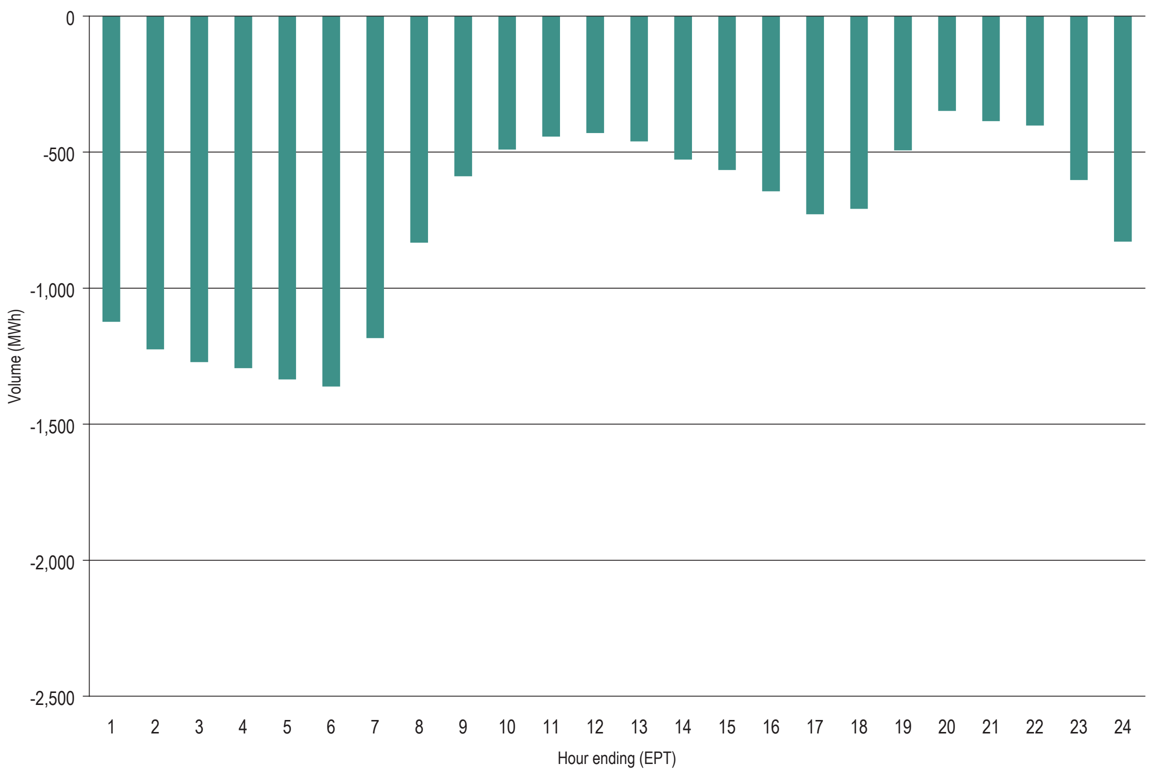
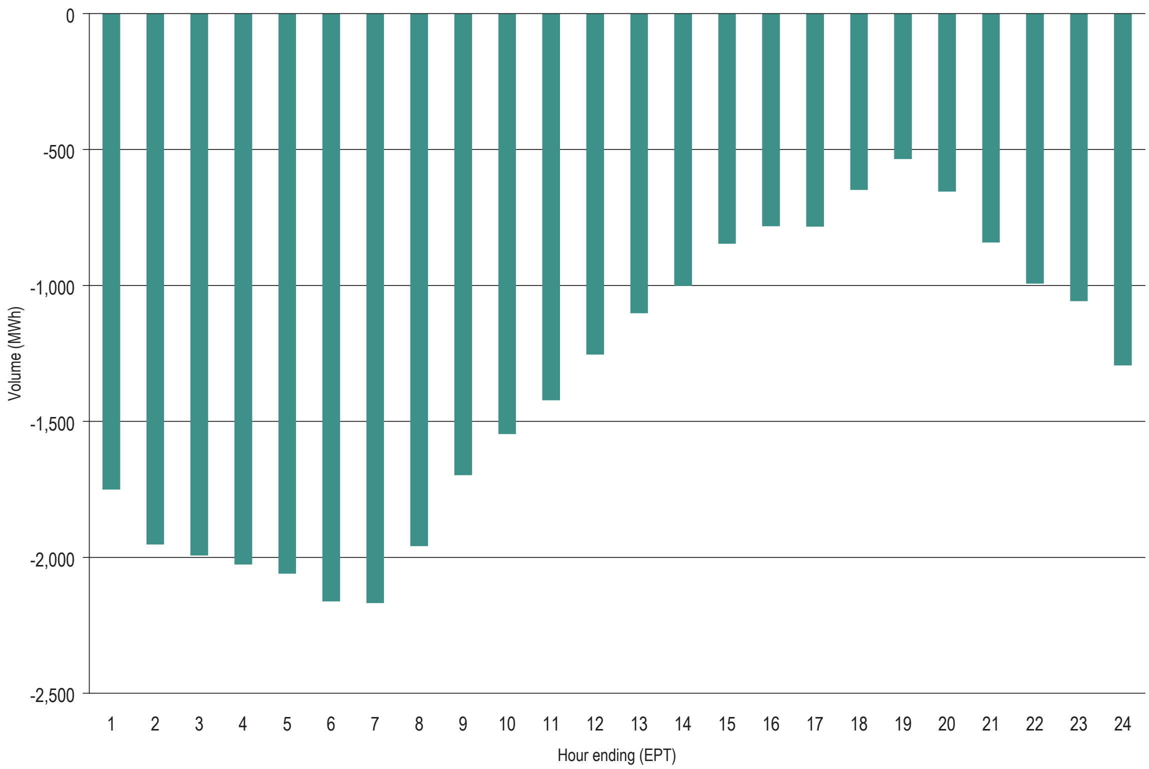


Figure 4-9 - PJM/MECS interface average actual minus scheduled volume: Phase 5



The mismatch became even larger in Phase 5, with the off-peak difference between actual and scheduled flow averaging -1,926 MW compared to -1,203 MW in Phase 4 and the on-peak difference averaging -1,070 MW in Phase 5 compared to -541 MW in Phase 4. The average hourly scheduled exports at the PJM/MECS interface declined from -834 MW per hour in Phase 4 to -147 MW per hour in Phase 5. The actual exports, however, remained relatively unchanged at -1,601 MW per hour in Phase 4 and -1,503 MW per hour in Phase 5. As a result, the difference between actual and scheduled flows increased in Phase 5.

The PJM/TVA interface also exhibited large mismatches between scheduled and actual power flows. The experience at the PJM/TVA interface is different from that at the PJM/MECS interface in that the net difference between scheduled flows and actual flows is imports while the net difference at the PJM/MECS interface is exports. (See Figure 4-10 and Figure 4-11.) Exports are scheduled, but actual flows are imports so the net difference is imports rather than exports. In Phase 4, the average hourly scheduled flow was -354 MW per hour (export) while actual flow was 516 MW per hour (import) for a difference of 870 MW. This general pattern continued in Phase 5, but the difference was larger. In Phase 5 average hourly scheduled flow was -1,157 MW while actual flow was 36 MW, for a difference of 1,193 MW.

The PJM/MECS differences and the PJM/TVA differences are in opposite directions and therefore create loop flow across PJM. The excess of actual over scheduled exports at PJM/MECS is in part met by the excess of actual over scheduled imports at PJM/TVA.

Figure 4-10 - PJM/TVA average flows: Phase 4

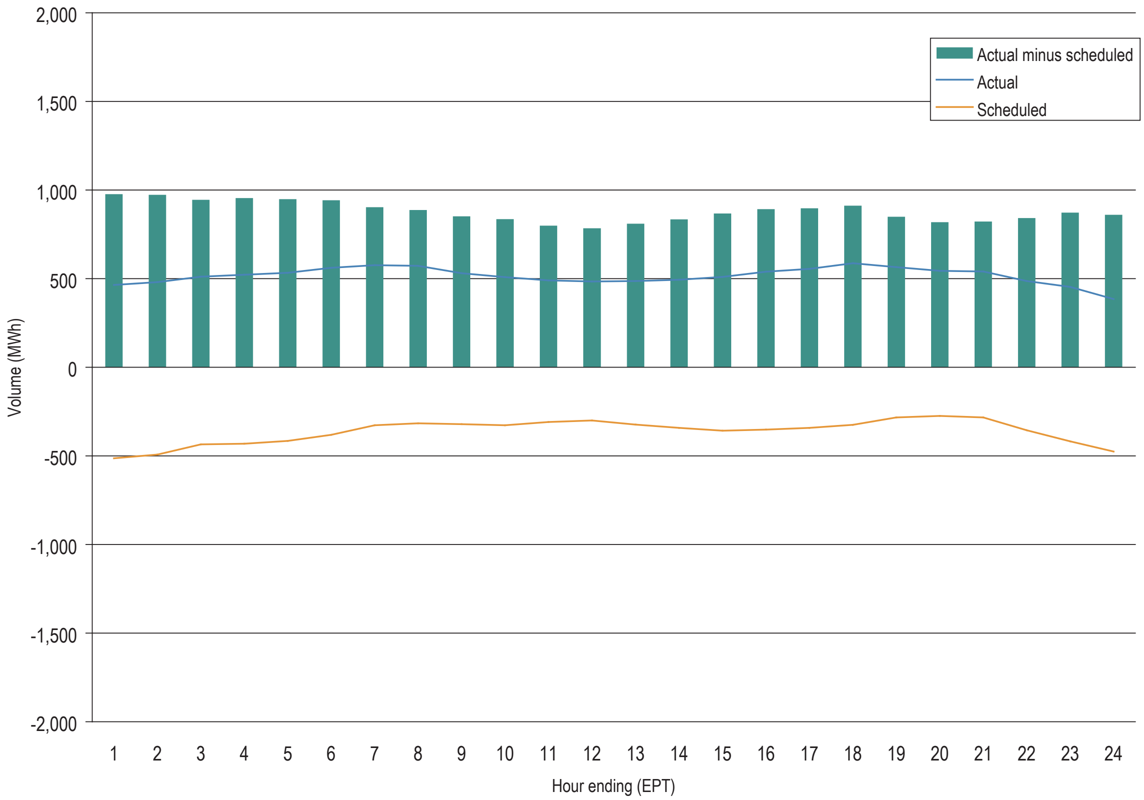
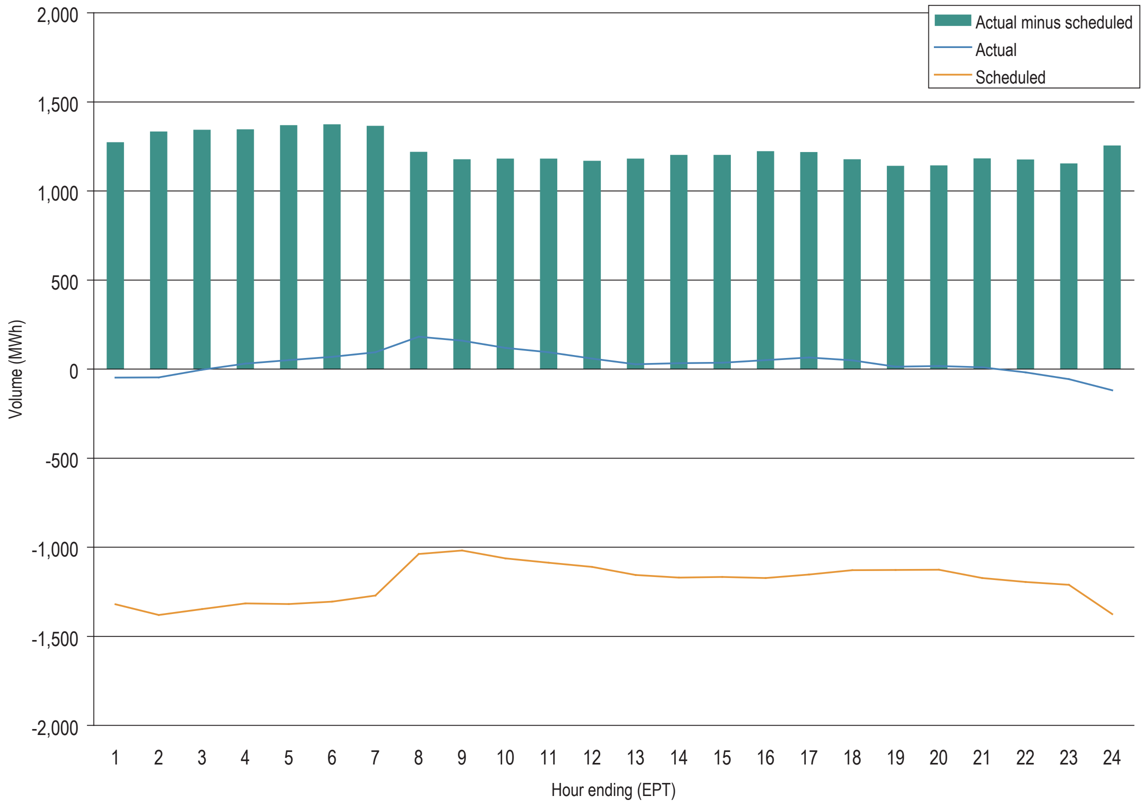


Figure 4-11 - PJM/TVA average flows: Phase 5



The differences between scheduled and actual flows at specific interfaces are a potentially significant concern, constituting unscheduled use of PJM's transmission system, affecting real-time system operations and affecting FTR revenue adequacy because loop flows do not pay congestion costs. The reasons for the identified differences between scheduled and actual flows remain unclear. It would be appropriate for PJM and the Midwest ISO to cooperate in an analysis of the underlying issues in order to identify the sources of loop flow and to create a solution.

Interchange Issues

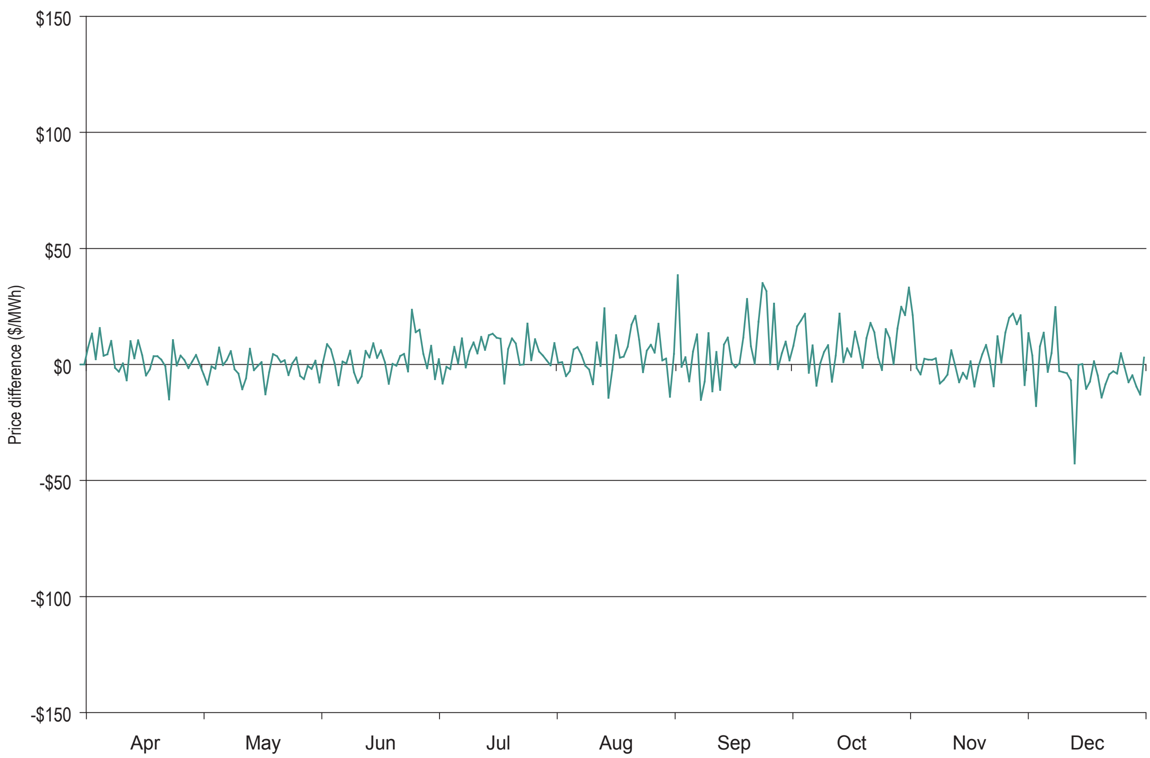
Prices at the borders between PJM and the NYISO and PJM and the Midwest ISO were consistent with competitive pressures. A wheeling contract between New York's Consolidated Edison and New Jersey's PSEG requires involvement from both PJM and NYISO as operators of the relevant transmission facilities. PJM is considering development of rules that would limit a market participant's ability to reserve more ramp than is actually either needed or used to contribute to more efficient use of transmission capability between PJM and surrounding markets.

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 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 PJM generator buses[14] in its calculation of the MISO/PJM interface price.

The 2005 hourly average prices for PJM/MISO and the MISO/PJM interface price were $48.84 and $52.12, respectively. The simple average difference between the PJM/MISO interface price and the MISO/PJM interface price was $3.28 in 2005, approximately 7 percent of the average PJM/MISO price. (See Figure 4-12.) The MISO/PJM interface price was higher on average than the PJM/MISO price in 2005. The simple average interface price difference does not reflect the underlying hourly variability in prices during 2005.

Figure 4-12 - Daily hourly average price difference (Midwest ISO interface - PJM/MISO): Calendar year 2005



13 See “LMP Aggregate Definitions” <http://www.pjm.com/markets/energy-market/downloads/20060103-aggregate-definitions.xls> (1.33 MB).
14 Based on information obtained from the Midwest ISO Extranet (October 21, 2005) <http://extranet.midwestiso.org/>.

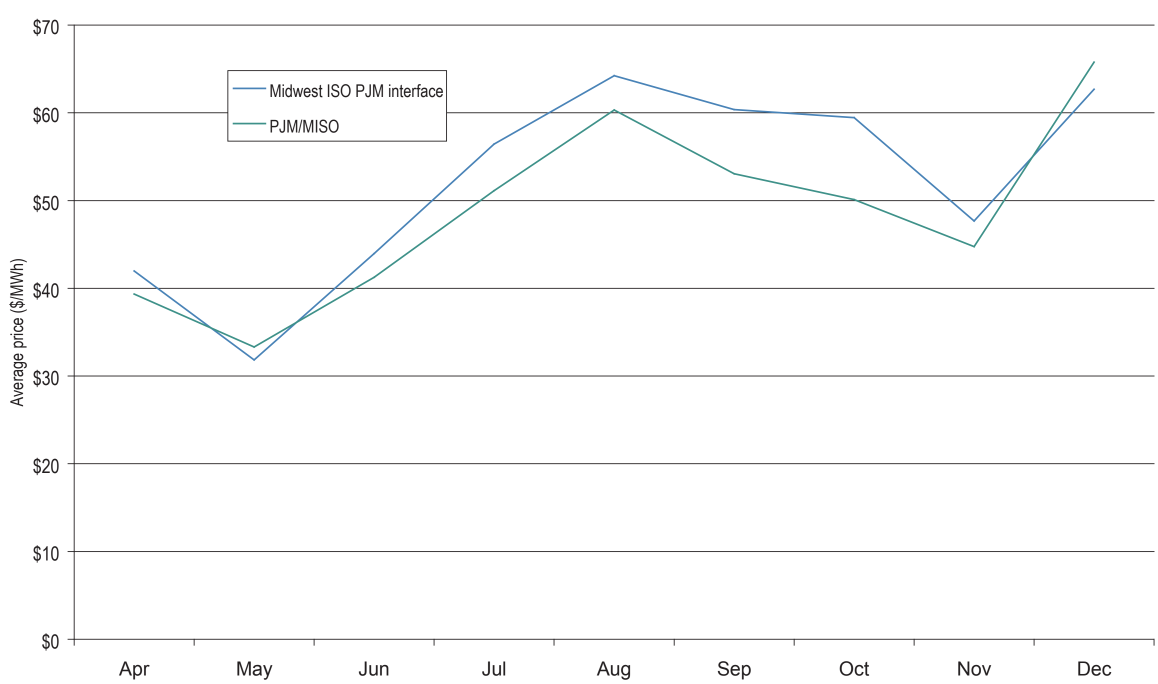
There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

During 2005, the difference between the PJM/MISO interface price and the MISO/PJM interface price fluctuated between positive and negative about nine times per day. The standard deviation of hourly price was $31.09 in 2005 for the PJM/MISO price, and $33.25 in 2005 for the MISO/PJM interface price. The standard deviation of the difference in interface prices was $23.30 in 2005. The average of the absolute value of the hourly price difference was $15.49 in 2005. 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 2005 period. Figure 4-13 shows this correlation between hourly PJM and Midwest ISO interface prices.

Figure 4-13 - Monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: Calendar year 2005



PJM and NYISO Interface Pricing

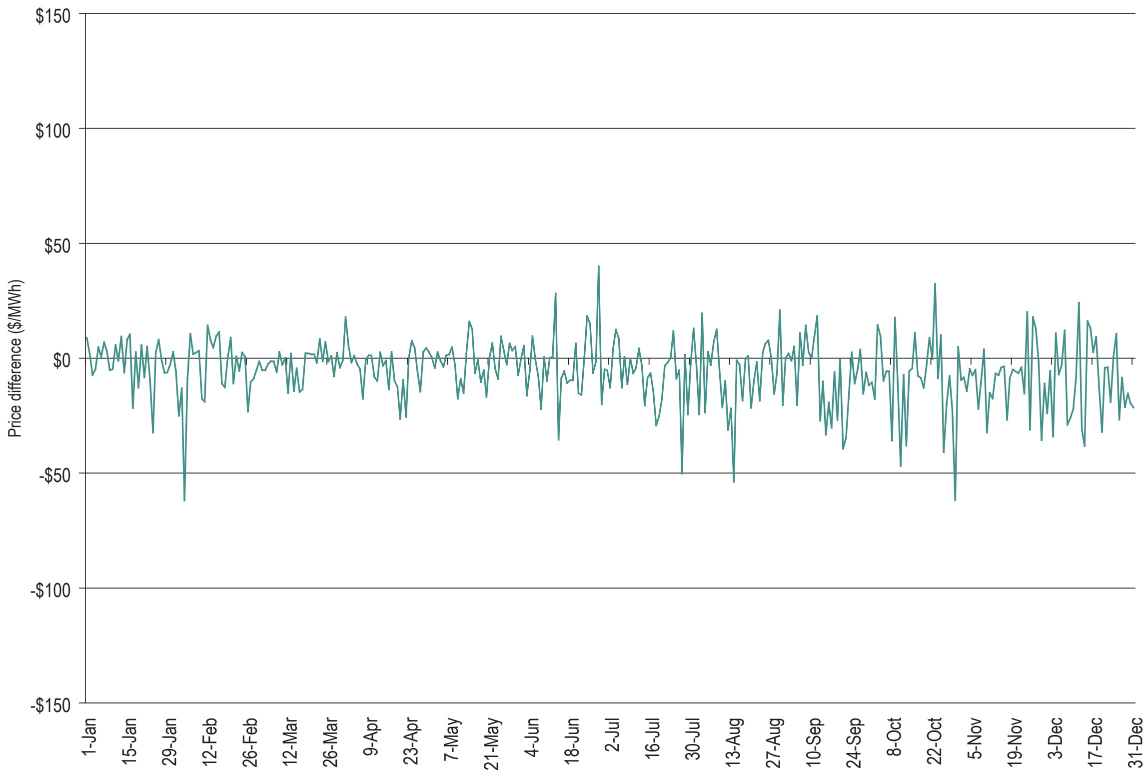
If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces 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 2005 hourly average price for PJM/NYIS and the NYISO/PJM proxy bus price were $67.15 and $61.83, respectively. The simple average difference between the PJM/NYIS interface price and the NYISO/PJM proxy bus price increased from -$2.39 per MWh in 2004 to -$5.32 per MWh in 2005 and the variability of the difference also increased. (See Figure 4-14.) The fact that PJM's net export volume to New York for 2005 is 39 percent lower than the four-year, 2001-to-2004 average is at least partially consistent with the fact that the PJM/NYIS price is greater than the NYISO/PJM price and that the difference increased in 2005. The simple average interface price difference does not reflect the continuing, substantial underlying hourly variability in prices during 2004 and 2005.

15 See also the discussion of these issues in the *2003 State of the Market Report*, Section 3, "Interchange Transactions."
16 See PJM's LMP Aggregate Definitions < http://www.pjm.com/markets/energy-market/downloads/20060103-aggregate-definitions.xls> (1.33 MB).

Figure 4-14 - Daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2005



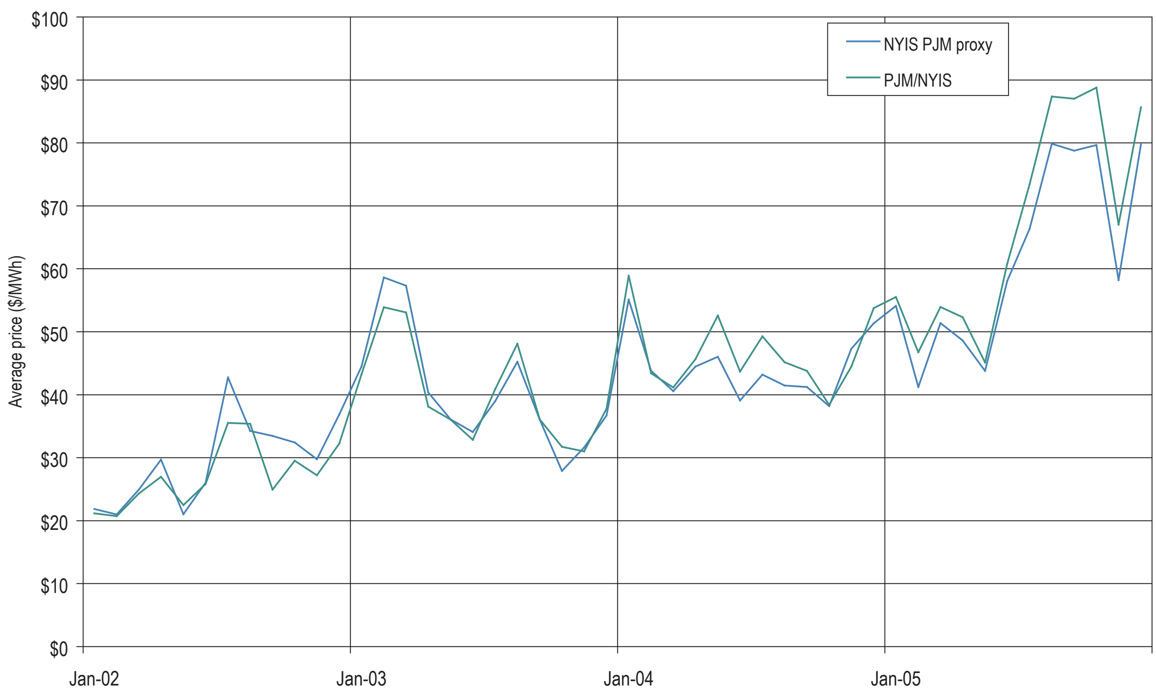
There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

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 2005 as it did in 2003 and 2004. The standard deviation of hourly price was $25.00 in 2003, $23.64 in 2004 and $42.93 in 2005 for the PJM/NYIS price and $37.72 in 2003, $30.00 in 2004 and $41.57 in 2005 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 and $40.22 in 2005. The average of the absolute value of the hourly price difference was $16.13 in 2003, $14.01 in 2004 and $23.44 in 2005. 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 2005. Figure 4-15 shows this correlation between hourly PJM and NYISO interface prices.

Figure 4-15 - Monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2005



As previously noted,[17] institutional difference between PJM and NYISO markets partially explain observed differences in border prices. The NYISO requires hourly bids or offer prices for each export or import transaction and clears its market each hour based on hourly bids.[18] 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.[19] The duration of

17 See *2003 State of the Market Report*, pp. 105-107; and *2004 State of the Market Report*, pp. 138-140.
18 See "NYISO Transmission Services Manual, Version 2.0" (February 1, 2005) < http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (462 KB).
19 See "PJM Manual 11: Scheduling Operations" (November 9, 2005) < http://www.pjm.com/contributions/pjm-manuals/pdf/m11v26.pdf > (448 KB).

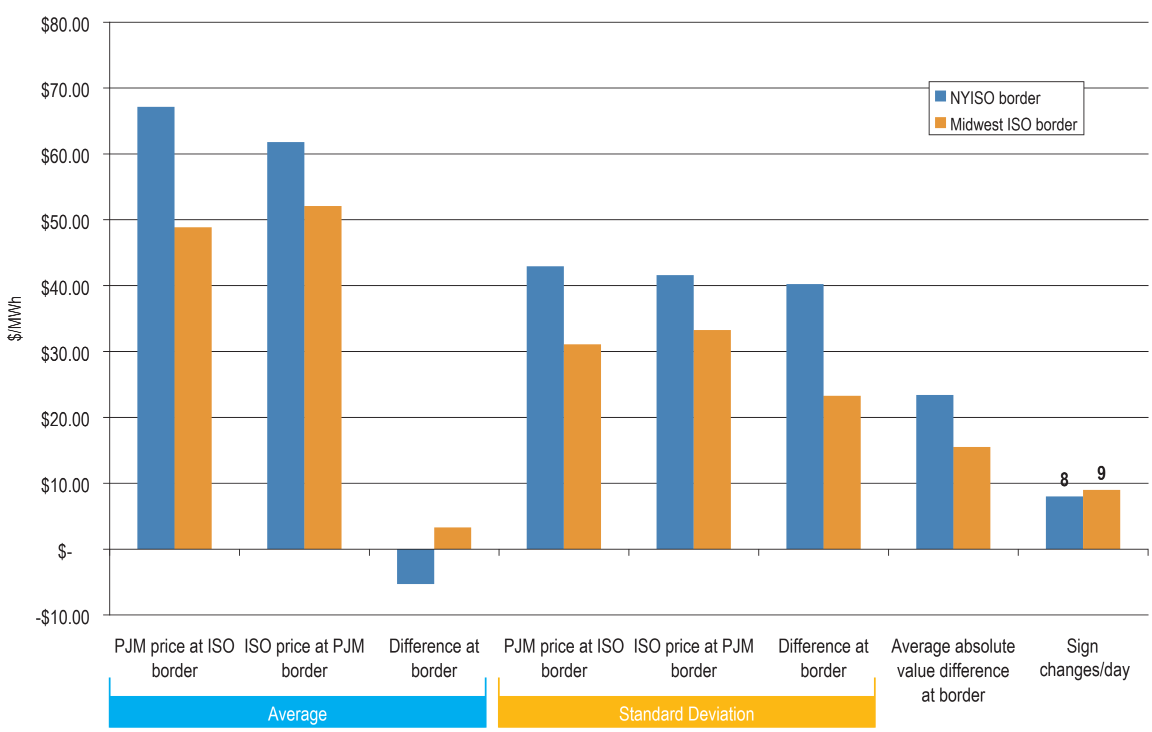
the requested transaction can vary from a single hour to an unlimited amount of time. Generally PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, only about 1 percent of all transactions submit 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 could 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.

The key features of PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-16 including average prices and measures of variability.

Figure 4-16 - PJM, NYISO and Midwest ISO border price averages: Calendar year 2005



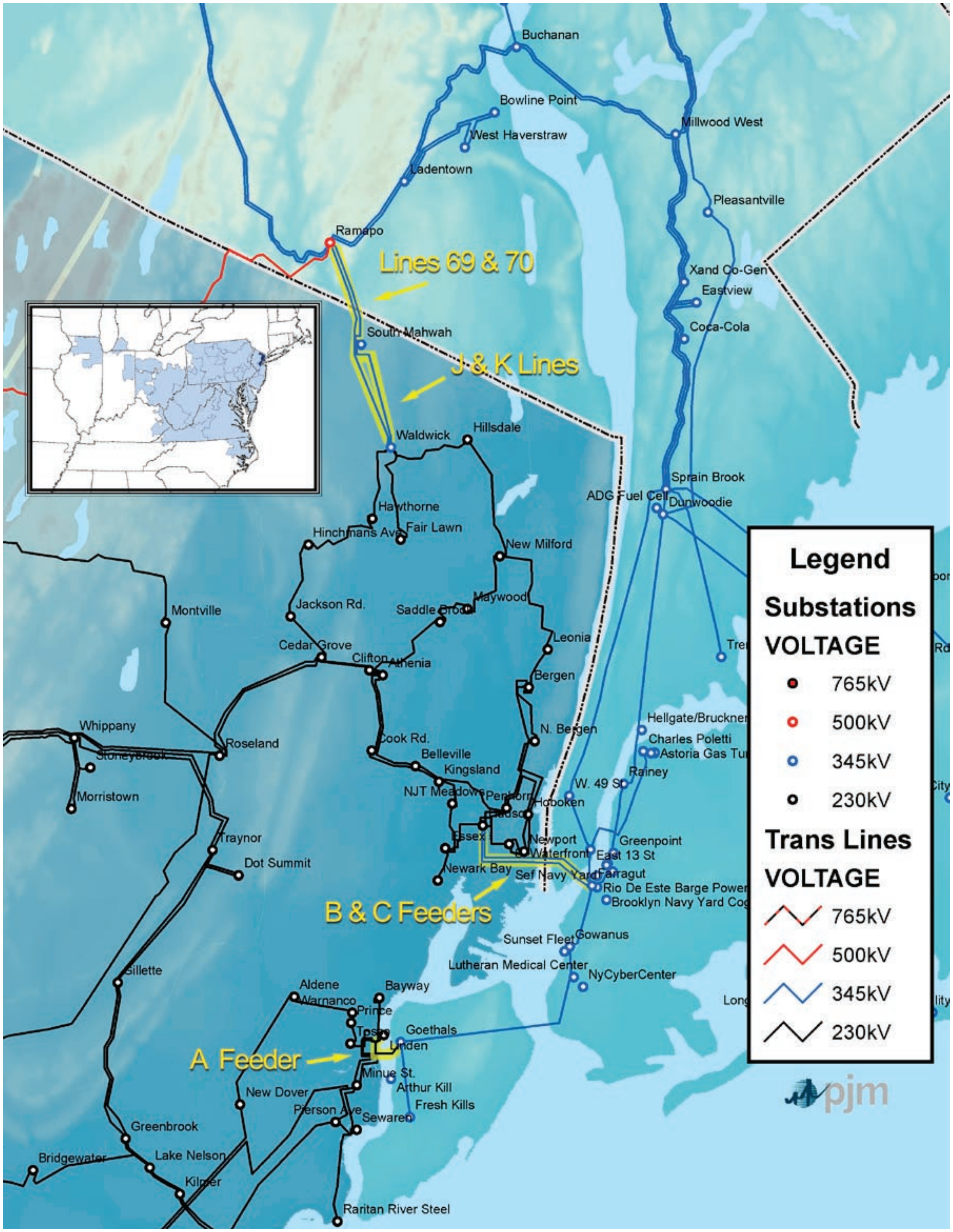
Consolidated Edison Company and PSEG Wheeling Contracts

To help meet the demand for power in New York City, Consolidated Edison Company 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 Consolidated Edison/PSEG contracts governing the New Jersey path evolved during the 1970s and were the subject of a Consolidated Edison complaint to the FERC in 2001. In July 2005, a FERC-approved protocol was implemented to resolve the matter. Based on the experience to date, Consolidated Edison has made formal recommendations to increase delivery performance.

Background

The contracts provide for the delivery of up to 1,000 MW of power from Consolidated Edison's Ramapo Substation in Rockland County, New York to PSEG at its Waldwick Switching Substation in Bergen County, New Jersey. PSEG then wheels the power across its system and delivers it back to Consolidated Edison across lines connecting directly into the city. (See Figure 4-17.) Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSEG'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, Consolidated Edison alleged that PSEG had underdelivered on the agreements and asked the FERC to resolve the issue.

Figure 4-17 - Consolidated Edison and PSEG wheel



In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[20] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Consolidated 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 PSEG to pay congestion charges associated with the daily elected level of service under the 600 MW contract and obligate Consolidated 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, PSEG is assigned FTRs associated with the 600 MW contract. The PSEG FTRs are treated like all other FTRs. For the six-month period, PSEG's FTR revenues were less than the associated congestion charges by $2.1 million because, for the entire PJM FTR Market, revenue was insufficient to fully fund FTRs. Under the FERC order, Consolidated 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 six-month period, Consolidated Edison's congestion credits were less than the associated congestion charges by $8.2 million. (See Table 4-7.)

20 111 FERC ¶ 61,228 (2005).

Table 4-7 - Consolidated Edison and PSEG wheel settlements data: July through December 2005

		Consolidated Edison			PSEG		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
July	Congestion Charge	$1,170,519.50	$9,347.11	$1,179,866.61	$1,843,902.00		$1,843,902.00
	Congestion Credit			$500,826.79			$1,805,338.00
	Net Charge			$679,039.82			$38,564.00
August	Congestion Charge	$810,156.00	($344.54)	$809,811.46	$1,215,234.00		$1,215,234.00
	Congestion Credit			$487,697.85			$1,204,398.08
	Adj. (July)						($7,229.66)
	Net Charge			$322,113.61			$18,065.58
September	Congestion Charge	$2,185,169.20	($6,757.30)	$2,178,411.90	$3,524,946.00		$3,524,946.00
	Congestion Credit			$477,322.41			$3,010,261.74
	Adj. (August)						$82.65
	Net Charge			$1,701,089.49			$514,601.61
October	Congestion Charge	$3,589,016.12	$386,018.03	$3,975,034.15	$5,668,896.00	$28,576.01	$5,697,472.01
	Congestion Credit			$341,601.81			$4,639,686.70
	Adj. (September)						$1,140.07
	Net Charge			$3,633,432.34			$1,056,645.24
November	Congestion Charge	$697,700.00	$282,714.23	$980,414.23	$1,088,712.00		$1,088,712.00
	Congestion Credit			$143,173.40			$856,827.21
	Adj. (October)			($17,330.68)			($26,088.71)
	Net Charge			$854,571.51			$257,973.50
December	Congestion Charge	$1,143,544.00		$1,143,544.00	$1,715,316.00		$1,715,316.00
	Congestion Credit			$159,398.53			$1,492,410.30
	Adj. (November)						$365.50
	Net Charge			$984,145.47			$222,540.20
Total	Congestion Charge	$9,596,104.82	$670,977.53	$10,267,082.35	$15,057,006.00	$28,576.01	$15,085,582.01
	Congestion Credit			$2,110,020.79			$13,008,922.03
	Adj.			($17,330.68)			($31,730.15)
	Net Charge			$8,174,392.24			$2,108,390.13

The Real-Time Energy Market Process

Under the terms of the protocol, Consolidated 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.

Market Monitoring

The FERC order asked the market monitors for both PJM and NYISO to evaluate their ability to perform investigations ensuring that neither gaming nor abuse of market power occur. The PJM MMU has seen nothing during the protocol's initial six-month period that would require the MMU 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.

Consolidated Edison Company September 2005 Status Report

On September 30, 2005, in compliance with the May 2005 FERC order, Consolidated Edison filed a status report with the FERC in which it criticized PJM and NYISO for performance under the protocol, but expressed a willingness to work with both to address areas of concern. PJM has increased operator training, PJM and NYISO hold weekly meetings to review protocol performance and to discuss operational issues and any open items and system software improvements are under development that will aid in the operation of the protocol.

Ramp and Transmission Reservation Issues

PJM limits the amount of change in net interchange, or ramp, between 15-minute intervals in order to ensure compliance with NERC performance standards. 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.

There are several issues associated with ramp rules. Ramp rules do not appear to provide adequate time to submit transactions to replace transactions that have been forced to expire. As a more general matter, ramp rules do not appear to provide adequate incentives for the efficient use of ramp. Ramp rules also permit the submission of transactions solely to create ramp room in the opposite direction. While these issues have arisen and been addressed on a case by case basis, neither PJM nor the MMU have assessed the overall extent or impact of the identified issues.

While ramp limits may be modified by PJM depending on system conditions, the limit is generally 1,000 MW for imports and exports for all hours. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions is -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 did not exceed 1,000 MW in either direction.

Market participants at times request and receive ramp reservations that are not used for an energy transaction. When this happens, other market participants can be prevented from obtaining ramp reservations. This behavior can reflect attempts to manipulate PJM prices, to disadvantage competitors or simply mistakes by participants. To help ensure efficient use of available ramp, PJM rules force unused ramp reservations to expire 30 minutes before they are scheduled to flow if they are not backed up with an actual energy transaction. This leaves only 10 minutes for another participant to request the ramp because PJM rules require that transactions be submitted only up to 20 minutes prior to the scheduled start time for hourly transactions.[21] While this rule contributes to the efficient use of ramp, given that it requires time to assemble the components of a transaction, the existing rules may free unused ramp when it is too late for other market participants to make effective use of it. In other words, ramp reservations become available with little time for others to use them and can effectively block other participants from the market.

It is possible for participants to hold transmission service reservations for relatively long periods without using it, making it unavailable for efficient use. Market participants may make OASIS reservations for daily firm transmission at the earliest possible time allowed under PJM rules (i.e., by 1400 hours three business days before the start date) and hold such a reservation without taking any action to create a corresponding transaction. As the participant does not have to pay for the reservation, there is no incentive to release it.

PJM rules permit the artificial creation of ramp room using a ramp reservation in the opposite of the desired direction. This approach may be used to create apparent ramp room in the desired direction. 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 30 minutes prior to flow.

These problems can be addressed by modifications to PJM rules. A possible solution to the expiration timing rules would be to set different time limits for reservations. For example, if less than 24 hours remain between the times when a reservation is requested and when the transaction will flow, then a reservation not backed up by a scheduled transaction could have a shortened time limit between time of request and automatic expiration. The time period could be extended for requests made more than 24 hours in advance. Such a procedure would require market participants to either complete their transaction or make the ramp available to other participants.

21 See "PJM Manual 11: Scheduling Operations" (November 9, 2005), p. 99 < http://www.pjm.com/contributions/pjm-manuals/pdf/m11v26.pdf > (448 KB).

SECTION 5 – CAPACITY MARKETS

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 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 Capacity Credit Markets. The PJM Capacity Credit Market is intended to provide a transparent, market-based mechanism for competitive 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 Capacity Credit Market permits LSEs to match capacity resources with short-term shifts in retail load while Interval, Monthly and Multimonthly Capacity Credit Markets provide mechanisms to match longer term obligations with capacity resources.

From June 2004 through May 2005 a separate ComEd Capacity Credit Market operated, under the terms of PJM rules, to balance supply of and demand for capacity unmet by the bilateral market or self-supply in the ComEd Control Area.[4] The ComEd Capacity Credit Market consisted of Interval, Monthly and Multimonthly Capacity Credit Markets.

During the last two calendar years, PJM has 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. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[5]

- **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,[6] and the Allegheny Power Company (AP) Control Zone.[7]

- **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).[8]

1 See Appendix H, "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 Markets. 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 All ComEd Capacity Market values (capacities) are in terms of installed MW.

5 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

6 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

7 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 the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

8 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).

- **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.

Overview

When the 2004 calendar year ended, PJM was operating two Capacity Markets, the PJM Capacity Market and the ComEd Capacity Market. The PJM Capacity Market (or simply PJM) was comprised of the 11 control zones of the Mid-Atlantic Region and the AP, AEP and DAY Control Zones. DLCO, which joined PJM on January 1, 2005, and Dominion, which joined PJM on May 1, 2005, were added to the PJM Capacity Market on the dates they joined. The ComEd Capacity Market was comprised solely of the ComEd Control Zone.

The ComEd Capacity Credit Market was added to the PJM Capacity Credit Market on June 1, 2005, to create a single PJM Capacity Market.[9]

PJM Capacity Market

Market Structure for the PJM Capacity Market

Ownership Concentration

- **Phase 4.** Structural analysis of the PJM Capacity Credit Market found that, on average, its daily markets exhibited low concentration levels while its monthly and multimonthly markets exhibited moderate concentration levels during the period January through April 2005.

- **Phase 5.** Structural analysis of the PJM Capacity Credit Market found that, on average, its daily markets exhibited moderate concentration levels while its monthly and multimonthly markets exhibited high concentration levels during the period May through December 2005.

- **Total Capacity.** The Capacity Credit Markets include approximately 5 percent of total capacity obligations. The MMU also analyzed the ownership of total PJM capacity in order to develop a more complete assessment of market structure for capacity. The ownership of total capacity exhibited low concentration levels throughout the year, decreasing from an HHI of 953 on January 1 to 917 on

9 For purposes of Section 5, “Capacity Markets” and Appendix E, “Capacity Markets,” these markets are identified as the PJM Capacity Market (or PJM) and the ComEd Control Zone Capacity Market (or ComEd). These markets are referred to collectively as the Capacity Markets for the regional transmission organization (RTO).

December 31. The highest market share declined from 21.6 percent to 16.6 percent. There was a single pivotal supplier throughout the year, meaning that the capacity of the largest supplier was always required in order to meet the capacity obligation.

Supply and Demand

- **Phase 4.** From January through April 2005, unforced capacity and obligations remained relatively constant in the PJM Capacity Market as compared to Phase 3. Average unforced capacity rose by 2,123 MW or 2.0 percent to 110,545 MW. Average load obligations climbed by 1,295 MW or 1.3 percent to 100,201 MW or 10,344 MW less than average unforced capacity. Overall Capacity Credit Market transactions increased by 18.7 percent from Phase 3. Daily Capacity Credit Market volumes increased by 44.7 percent, while Monthly and Multimonthly Capacity Credit Market volumes increased by 16.4 percent and 10.7 percent, respectively.

- **Phase 5.** From May through December 2005, unforced capacity and obligations increased with Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Average unforced capacity rose 35.6 percent to 149,888 MW. Average load obligation climbed 39.5 percent to 139,736 MW. Overall Capacity Credit Market transactions increased by 22.0 percent from Phase 4. Daily Capacity Credit Market volumes increased by 9.3 percent, while Monthly and Multimonthly Capacity Credit Market volumes increased by 35.7 percent and 23.8 percent, respectively.

External and Internal Capacity Transactions

- **Phase 4.** From January through April 2005, imports averaged 5,855 MW, which was a decrease of 537 MW or 8.4 percent from the Phase 3 average of 6,392 MW. Exports averaged 3,953 MW, which was an increase of 742 MW or 23.1 percent from the Phase 3 average of 3,211 MW. Average net exchange decreased 1,279 MW or 40.2 percent to 1,902 MW from the Phase 3 average of 3,181 MW. Internal bilateral transactions averaged 91,880 MW, which was an increase of 14,712 MW or 19.1 percent from the 77,168 MW average for Phase 3.

- **Phase 5.** From May through December 2005, imports averaged 4,208 MW, which was a decrease of 1,647 MW or 28.1 percent from the Phase 4 average. Exports averaged 4,856 MW, which was an increase of 903 MW or 22.8 percent from the Phase 4 average. Average net exchange decreased 2,550 MW or 134.1 percent to -648 MW from the Phase 4 average of 1,902 MW. These changes were the result of the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Internal bilateral transactions averaged 150,597 MW, which was an increase of 58,717 MW or 63.9 percent from the average for Phase 4. This increase was the result of Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market.

Active Load Management (ALM Credits)

- **Phase 4.** From January through April 2005, ALM credits in the PJM Capacity Market averaged 1,654 MW, down less than 1 percent from 1,662 MW in Phase 3.

- **Phase 5.** From May through December 2005, ALM credits in the PJM Capacity Market averaged 1,993 MW, an increase of 339 MW or 20.5 percent from Phase 4. This increase was attributable to the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1, 2005, as the mandatory interruptible load (MIL) credits in ComEd were converted to ALM credits in PJM.

Market Performance in the PJM Capacity Market

Capacity Credit Market Volumes and Prices

- **Phase 4.** From January through April 2005, total PJM Capacity Credit Market transactions averaged 5,649 MW (5.6 percent of obligation), which was 888 MW higher than the Phase 3 average (4.8 percent of obligation). Total PJM Capacity Credit Market prices averaged $7.72 per MW-day, which was $2.81 per MW-day less than the Phase 3 average.

- **Phase 5.** From May through December 2005, total PJM Capacity Credit Market transactions averaged 6,892 MW (4.9 percent of obligation), which was 1,243 MW higher than the Phase 4 average. Total PJM Capacity Credit Market prices averaged $5.47 per MW-day, which was $2.25 per MW-day less than the Phase 4 average.

- **Calendar Years 1999 through 2005.** Daily Capacity Market volume declined from 2.5 percent of average obligation in 2000 to 1.2 percent in 2005.[10] Monthly and Multimonthly Capacity Market volume increased from 3.0 percent of obligation in 2000 to 3.9 percent of average obligation in 2005. Capacity Market prices increased from 1999 through 2001 and have declined and remained relatively stable since 2001 with the exception of the summer of 2004.

ComEd Capacity Market

Market Structure for the ComEd Capacity Market

Ownership Concentration

- **June 2004 through May 2005.** Structural analysis of the ComEd Capacity Credit Market found that its Monthly and Multimonthly Markets exhibited high levels of concentration.

- **Total Capacity.** The ComEd Capacity Credit Markets include about 6 percent of total ComEd capacity obligations. The MMU also analyzed total ComEd capacity in order to develop a more complete assessment of market structure for capacity. The ownership of total capacity exhibited high concentration levels throughout the year, with HHI declining from 4525 on June 1, 2004, to 4070 on May 31, 2005, and with the maximum market share declining from 64.2 percent to 59.8 percent and RSI below 1.0 throughout the year, indicating the presence of a single pivotal supplier. The presence of a single pivotal supplier means that the capacity of the largest supplier was always required in order to meet the capacity obligation.

10 The year 2000 is used as the base year because it was the first full calendar year for which unforced capacity was used rather than installed capacity.

Supply and Demand

- **June 2004 through May 2005.** ComEd electricity distribution companies (EDCs) together had an 81.6 percent market share of load obligation. During this period, capacity resources exceeded capacity obligations in the ComEd Capacity Market every month, resulting in an average net excess of 6,261 MW, or 31.7 percent of average obligation for the period.

External and Internal Capacity Transactions

- **June 2004 through May 2005.** The ComEd Control Zone was a net exporter of capacity resources, with exports increasing from 747 MW on June 1 to 2,289 MW on May 31. Almost half of the increase was the result of increased exports to the PJM Capacity Market. Imports remained relatively constant. Internal bilateral transactions decreased by 6,361 MW on October 1 due to the lower interval peak for the October to December period.

Market Performance in the ComEd Capacity Market

Capacity Credit Market Volumes and Prices

- **June 2004 through May 2005.** Total ComEd Capacity Credit Market transactions averaged 1,229 MW, which was 6.2 percent of load obligation. Prices averaged $23.99 per MW-day.

Generator Performance

From 1996 to 2001, the average, PJM equivalent demand forced outage rate (EFORd) declined, reaching 4.6 percent in 2001, but then increased to 5.2 percent in 2002, 7.0 percent in 2003 and 8.0 percent in 2004.[11] In 2005, the average PJM EFORd decreased to 7.3 percent. The decrease in EFORd from 2004 to 2005 was the result of decreased forced outage rates across all unit types with the exception of combustion turbines. These forced outage rates are for the PJM Mid-Atlantic Region and the AP Control Zone only. The forced outage rate in 2005 was 6.5 percent for all zones within the PJM Control Area.[12]

Conclusion

The PJM Market Monitoring Unit (MMU) analyzed key measures of PJM Capacity Market and of ComEd Capacity Market structure and performance for calendar year 2005 and for the period from June 2004 through May 2005 for ComEd, including concentration ratios, prices, outage rates and reliability. Given the basic features of market structure in both the PJM and ComEd Capacity Markets, including high levels of concentration, the relatively small number of 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 is high. Market power is endemic to the existing structure of PJM Capacity Markets.

11 As a general matter, the current year EFORd data reported in prior state of the market reports may be revised based on final data submitted after the publication of the report as final EFORd data are not available until after the publication of the reports.

12 In some cases, data for the AEP, DAY, DLCO, Dominion and ComEd Control Zones may be incomplete for the years 2004 and 2005. Only data that have been reported to PJM were used.

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 even in a highly concentrated market. 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.

The MMU found serious market structure issues, but no exercise of market power during these time periods. 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 2005. The PJM Capacity Market results were competitive during 2005. The ComEd Capacity Market results were reasonably competitive for the 12-month period from June 2004 through May 2005. Market power remains a serious concern for the MMU in the PJM Capacity Market based on market structure conditions in this market.

Market Structure for the PJM Capacity Market

The PJM Capacity Markets continued to evolve during Phases 4 and 5 of calendar year 2005, with the integrations of DLCO, Dominion and ComEd on the first days of January, May and June, respectively. The MMU analyzed capacity ownership concentration, internal sources of supply and demand, capacity credit transactions, internal and external bilateral capacity transactions and load management activity.

Ownership Concentration

Ownership 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 dominate 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

13 See 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.

share. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.0 for a single generation owner clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power. For example, suppliers can be jointly pivotal. If the RSI is greater than 1.0, the supply of the specific generation owner is not needed to meet market demand and that generation owner has a reduced ability to unilaterally influence market price. If the RSI is less than 1.0, the supply owned by the specific generation owner is needed to meet market demand and the generation owner is a pivotal supplier with a significant ability to influence prices.

The MMU analyzed both HHI and RSI for PJM Capacity Markets during Phases 4 and 5 of calendar year 2005.

Phase 4

The HHI analysis indicates that, on average, the PJM Capacity Credit Markets in Phase 4 exhibited low levels of concentration in the Daily Capacity Credit Market and moderate levels of concentration in the Monthly and Multimonthly Capacity Credit Markets.[14] As shown in Table 5-1 and Table 5-2, HHIs for the Daily Capacity Credit Market averaged 964 during this period, with a maximum of 2660 and a minimum of 824 (four firms with equal market shares would result in an HHI of 2500). The highest market share for any entity in a daily auction was 49.1 percent, while two of 120 daily auctions (1.7 percent) had an HHI greater than 1800. HHIs for the longer term Monthly and Multimonthly Capacity Credit Markets averaged 1705, with a maximum of 2954 and a minimum of 841 (three firms with equal market shares would result in an HHI of 3333). The highest market share for any entity in a monthly/multimonthly auction was 50.6 percent, while eight out of 23 monthly/multimonthly auctions (34.8 percent) had an HHI greater than 1800.

The RSI analysis indicates that, while there were no significant pivotal supplier issues in the Daily Capacity Credit Market in PJM for Phase 4, such issues did exist in the Monthly and Multimonthly Markets for this period. Table 5-3 and Table 5-4 show RSI values for the Daily Capacity Credit Market Auctions and the Monthly and Multimonthly Capacity Credit Market Auctions for the PJM Capacity Market. The RSI results for the Daily Capacity Credit Market indicate that the average one pivotal supplier RSI level for Phase 4 was 5.03. The one pivotal RSI fell below 1.0 in none of the 120 daily auctions, and there were no daily auctions with three or fewer jointly pivotal suppliers. The one pivotal RSI results for the Monthly and Multimonthly Markets indicate that the average RSI was 1.84 with four of the 23 monthly auctions (17.4 percent) having RSI values less than 1.0, and 14 of the auctions (60.9 percent) having three or fewer jointly pivotal suppliers.

14 PJM Capacity Market results are reported by the time period during which the auction was run and not by the time period to which the auction applies.

Table 5-1 - PJM Capacity Market HHI: Calendar year 2005

Term	Statistic	Daily Market HHI	Monthly and Multimonthly Market HHI
	Average	964	1705
Phase 4	Minimum	824	841
	Maximum	2660	2954
	Highest Market Share	49.1%	50.6%
	Average	1093	2053
Phase 5	Minimum	674	1063
	Maximum	1756	5039
	Highest Market Share	37.7%	68.0%
	Average	1036	1865
Calendar Year	Minimum	674	841
	Maximum	2660	5039
	Highest Market Share	49.1%	68.0%

Table 5-2 - PJM Capacity Market HHI statistics: Calendar year 2005

Term		Daily Market	Monthly and Multimonthly Market
	# Auctions	120	23
Phase 4	# Auctions with HHI >1800	2	8
	% Auctions with HHI >1800	1.7%	34.8%
	# Auctions	245	40
Phase 5	# Auctions with HHI >1800	0	20
	% Auctions with HHI >1800	0.0%	50.0%
	# Auctions	365	63
Calendar Year	# Auctions with HHI >1800	2	28
	% Auctions with HHI >1800	0.5%	44.4%

Table 5-3 - PJM Capacity Market residual supply index (RSI): Calendar year 2005

Term	Statistic	Daily Market RSI	Monthly and Multimonthly Market RSI
Phase 4	Average	5.03	1.84
	Minimum	3.79	0.53
	Maximum	6.96	5.49
Phase 5	Average	3.27	0.68
	Minimum	1.56	0.16
	Maximum	6.19	3.13
Calendar Year	Average	4.04	1.36
	Minimum	1.56	0.16
	Maximum	6.96	5.49

Table 5-4 - PJM Capacity Market residual supply index (RSI) statistics: Calendar year 2005

Term		Daily Market	Monthly and Multimonthly Market
Phase 4	# Auctions	120	23
	# Auctions with RSI < 1.0	0	4
	% Auctions with RSI < 1.0	0.0%	17.4%
	# Auctions with <= 3 Pivotal Suppliers	0	14
	% Auctions with <= 3 Pivotal Suppliers	0.0%	60.9%
Phase 5	# Auctions	245	40
	# Auctions with RSI < 1.0	0	30
	% Auctions with RSI < 1.0	0.0%	75.0%
	# Auctions with <= 3 Pivotal Suppliers	0	37
	% Auctions with <= 3 Pivotal Suppliers	0.0%	92.5%
Calendar Year	# Auctions	365	63
	# Auctions with RSI < 1.0	0	34
	% Auctions with RSI < 1.0	0.0%	54.0%
	# Auctions with <= 3 Pivotal Suppliers	0	51
	% Auctions with <= 3 Pivotal Suppliers	0.0%	81.0%

Phase 5

The HHI analysis indicates that, on average, the PJM Capacity Credit Markets in Phase 5 exhibited moderate levels of concentration in the Daily Capacity Credit Market and high levels of concentration in the Monthly and Multimonthly Capacity Credit Markets. As shown in Table 5-1 and Table 5-2, HHIs for the Daily Capacity Credit Market averaged 1093 during this period, with a maximum of 1756 and a minimum of 674 (four firms with equal market shares would result in an HHI of 2500). The highest market share for any entity in a daily auction was 37.7 percent, while none of the 245 daily auctions had an HHI greater than 1800. HHIs for the longer term Monthly and Multimonthly Capacity Credit Markets averaged 2053, with a maximum of 5039 and a minimum of 1063 (three firms with equal market shares would result in an HHI of 3333). The highest market share for any entity in a monthly/multimonthly auction was 68.0 percent, while 20 out of 40 monthly/multimonthly auctions (50.0 percent) had an HHI greater than 1800.

The RSI analysis indicates that while there were no significant pivotal supplier issues in the Daily Capacity Credit Market in PJM for Phase 5, such issues did exist in the Monthly and Multimonthly Markets for this period. Table 5-3 and Table 5-4 show single pivotal supplier RSI values for the Daily Capacity Credit Market Auctions and the Monthly and Multimonthly Capacity Credit Market Auctions for the PJM Capacity Market. The RSI results for the Daily Capacity Credit Market indicate that the average RSI level for Phase 5 was 3.27. RSI did not fall below 1.0 in any of the 245 daily auctions, and there were no daily auctions with three or fewer jointly pivotal suppliers. The RSI results for the Monthly and Multimonthly Markets indicate that the average RSI was 0.68 with 30 of the 40 monthly auctions (75.0 percent) having RSI values less than 1.0 and 37 of the auctions (92.5 percent) having three or fewer jointly pivotal suppliers.

Total Capacity

The market structure analyses presented above focused on the operation of Capacity Credit Markets which include only about 5 percent of total capacity obligations traded in PJM-operated markets. To provide a more complete assessment of competition in the PJM Capacity Market, the MMU also analyzed total capacity without regard to whether it is sold in PJM-operated markets, through bilateral agreements or self-supplied.

The market structure for total capacity in the aggregate PJM market is shown for specific dates in Table 5-5. The analysis uses capacity ownership as of January 1 (DLCO joined PJM), May 1 (Dominion joined PJM), June 1 (integration of ComEd Capacity Market) and December 31, 2005.

The analysis shows that when Dominion joined PJM on May 1, obligation and unforced capacity increased while the total capacity ownership market shares of PJM members were reduced.[15] The decrease in market shares resulted in a lower level of market concentration, reflected in the decrease of HHI from 953 to 896. The maximum market share decreased from 21.6 percent to 18.2 percent. There was a single pivotal supplier throughout the year.

When the ComEd Capacity Market was integrated into the PJM Capacity Market on June 1, obligation and unforced capacity again increased. Total capacity ownership market shares of existing PJM members decreased with the exception of Exelon Corporation, whose market share increased, reflecting ownership

15 Dominion owned capacity in PJM before May 1, so its market share increased as a result of its integration.

of capacity in both ComEd and PJM. Exelon's higher market share led to a slight increase in market concentration, shown by an increase in HHI from 896 to 901. Capacity additions by existing capacity owners after June 1 resulted in an increase in HHI from 901 to 917 on December 31.[16]

Total capacity ownership was at low concentration levels throughout the year, decreasing from 953 on January 1 to 917 on December 31. The highest market share declined from 21.6 percent to 16.6 percent. There was a single pivotal supplier throughout the year.

Table 5-5 - PJM capacity: Calendar year 2005

	01-Jan	01-May	01-Jun	31-Dec
Unforced Capacity (MW)	109,675	129,869	152,328	153,326
Obligation (MW)	99,944	118,680	142,494	142,886
HHI	953	896	901	917
Highest Market Share	21.6%	18.2%	16.4%	16.6%
RSI	0.86	0.90	0.89	0.89
Pivotal Suppliers	1	1	1	1

Supply and 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.** PJM EDCs are entities with a franchise service territory within the PJM boundaries. 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.** Non-PJM EDCs are electricity distribution companies whose franchise service territories lie outside of PJM boundaries.
- **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.

16 See Section 3, "Energy Market, Part 2," for a more detailed discussion of capacity additions.

Phase 4

During Phase 4, PJM EDCs and their affiliates maintained a large market share of load obligations in the PJM Capacity Market, together averaging 85.0 percent (Figure 5-1 and Table 5-6), down from the 86.1 percent for Phase 3. The combined market share for Phase 4 of LSEs not affiliated with any EDC and of non-PJM EDC affiliates averaged 15.0 percent, up from the 13.9 percent for Phase 3.

Load-serving entities can meet their load obligations through self-supply,[17] the PJM Capacity Credit Market or bilateral contracts with third parties. As shown in Table 5-7, Table 5-8 and Table 5-9, reliance on these options varied by market sector.[18] During Phase 4, 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 63.5 percent of their load obligations with their remaining obligations being supplied through bilateral contracts with third parties (39.8 percent) and the PJM Capacity Credit Market (0.9 percent). The self-supply percentage is down from the Phase 3 value of 64.9 percent, while the bilateral contract percentage has increased from 37.9 percent for Phase 3. In Phase 4, entities in this sector, on average, purchased more capacity credits in the PJM Capacity Credit Market or through bilateral contracts with third parties than were required to meet their obligation, resulting in an average net excess of 2,037 MW (4.2 percent of obligation) as compared to a Phase 3 average net excess of 995 MW (2.0 percent of obligation) for this sector. In Phase 3 and Phase 4, all generating affiliate sectors owned more capacity than their load obligations, were net capacity credit sellers in either the PJM Capacity Credit Market or through bilateral contracts and remained in higher net excess positions as a percentage of load obligations than the other sectors. All marketing affiliate sectors, which were net capacity credit buyers in either the PJM Capacity Credit Market 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 Phase 3 and Phase 4. Volumes and percentages of load obligations for self-supply, the Capacity Credit Market and bilateral contracts for all generating affiliate and marketing affiliate sectors were approximately the same for Phase 3 and Phase 4.

System net excess capacity can be determined using unforced capacity, capacity obligation, the sum of members' excesses and the sum of members' deficiencies. Table 5-10 and Figure 5-2 present these data for Phase 4.[19] 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.

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

18 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.

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

During Phase 4, unforced capacity and obligations remained relatively constant in the PJM Capacity Market as compared to Phase 3. Average unforced capacity rose by 2,123 MW from 108,422 MW to 110,545 MW, an increase of 2.0 percent. Average load obligations increased 1,295 MW or 1.3 percent from 98,906 MW to 100,201 MW. During this period, capacity resources exceeded capacity obligations in PJM on every day and the daily average net excess was 10,344 MW (10.3 percent of average obligation), an increase of 829 MW from the average net excess of 9,515 MW for Phase 3 (9.6 percent of average obligation). This is considered an excess capacity position. 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.

Figure 5-1 - PJM Capacity Market load obligation served (Percent): Calendar year 2005

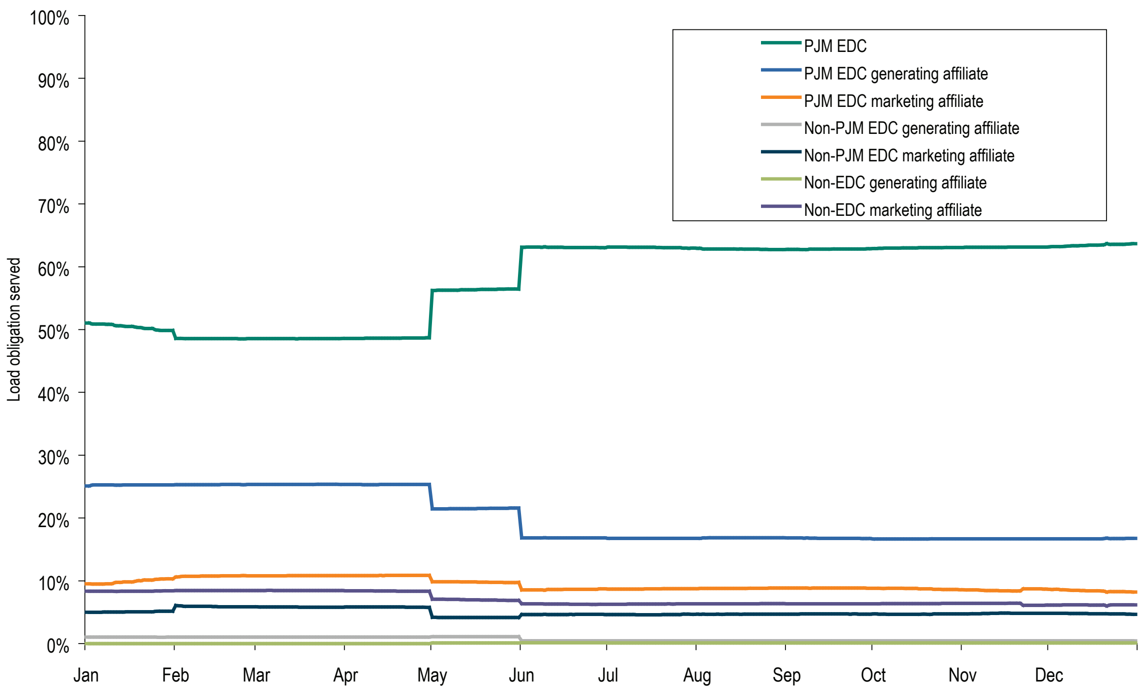


Table 5-6 - PJM Capacity Market load obligation served: Calendar year 2005

	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
Jan	50,489	25,269	9,879	1,025	5,063	0	8,355	100,080
Feb	48,642	25,359	10,772	1,025	5,920	0	8,465	100,183
Mar	48,664	25,404	10,841	1,026	5,830	0	8,467	100,232
Apr	48,779	25,403	10,875	1,026	5,829	0	8,400	100,312
May	66,893	25,527	11,631	1,309	4,939	125	8,275	118,699
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
				Phase 4				
Average	49,159	25,358	10,585	1,026	5,652	0	8,421	100,201
% of Total Obligation	49.1%	25.3%	10.6%	1.0%	5.6%	0.0%	8.4%	100.0%
				Phase 5				
Average	87,095	24,121	12,272	695	6,487	160	8,906	139,736
% of Total Obligation	62.3%	17.3%	8.8%	0.5%	4.6%	0.1%	6.4%	100.0%
				Calendar Year				
Average	74,623	24,528	11,718	804	6,213	107	8,746	126,739
% of Total Obligation	58.9%	19.4%	9.2%	0.6%	4.9%	0.1%	6.9%	100.0%

Table 5-7 - PJM Capacity Market load obligation served by PJM EDCs and affiliates: Calendar year 2005

	PJM EDCs					PJM EDC Generating Affiliates					PJM EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	31,215	560	20,542	50,489	1,828	49,248	12	(20,329)	25,269	3,662	0	549	9,785	9,879	455
Feb	31,213	432	18,749	48,642	1,752	49,255	(334)	(20,563)	25,359	2,999	0	796	10,235	10,772	259
Mar	31,181	282	19,436	48,664	2,235	49,255	(162)	(20,535)	25,404	3,154	0	936	10,187	10,841	282
Apr	31,172	400	19,522	48,779	2,315	49,254	(240)	(19,652)	25,403	3,959	0	969	10,197	10,875	291
May	49,055	153	19,885	66,893	2,200	51,177	92	(21,980)	25,527	3,762	0	1,170	10,795	11,631	334
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
								Phase 4							
Average	31,195	418	19,583	49,159	2,037	49,253	(177)	(20,268)	25,358	3,450	0	812	10,097	10,585	324
% of Total Obligation	63.5%	0.9%	39.8%	104.2%	4.2%	194.2%	(0.7%)	(79.9%)	113.6%	13.6%	0.0%	7.7%	95.4%	103.1%	3.1%
								Phase 5							
Average	50,490	434	38,430	87,095	2,259	63,712	(1,491)	(36,116)	24,121	1,984	0	1,546	11,043	12,272	317
% of Total Obligation	58.0%	0.5%	44.1%	102.6%	2.6%	264.1%	(6.2%)	(149.7%)	108.2%	8.2%	0.0%	12.6%	90.0%	102.6%	2.6%
								Calendar Year							
Average	44,146	429	32,234	74,623	2,186	58,958	(1,059)	(30,905)	24,528	2,466	0	1,305	10,732	11,718	319
% of Total Obligation	59.2%	0.6%	43.2%	103.0%	3.0%	240.4%	(4.3%)	(126.0%)	110.1%	10.1%	0.0%	11.1%	91.6%	102.7%	2.7%

Table 5-8 - PJM Capacity Market load obligation served by non-PJM EDC affiliates: Calendar year 2005

	Non-PJM EDC Generating Affiliates					Non-PJM EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	9,020	(649)	(5,316)	1,025	2,030	0	463	4,744	5,063	144
Feb	9,026	(570)	(5,572)	1,025	1,859	0	409	5,725	5,920	214
Mar	9,034	(553)	(5,830)	1,026	1,625	0	561	5,569	5,830	300
Apr	9,039	(394)	(5,740)	1,026	1,879	0	549	5,566	5,829	286
May	7,158	(315)	(3,836)	1,309	1,698	0	456	4,710	4,939	227
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
Phase 4										
Average	9,030	(542)	(5,614)	1,026	1,848	0	497	5,392	5,652	237
% of Total Obligation	880.5%	(52.8%)	(547.4%)	280.3%	180.3%	0.0%	8.8%	95.4%	104.2%	4.2%
Phase 5										
Average	12,801	(175)	(9,294)	695	2,637	0	575	6,595	6,487	683
% of Total Obligation	1841.8%	(25.2%)	(1337.2%)	479.4%	379.4%	0.0%	8.9%	101.7%	110.6%	10.6%
Calendar Year										
Average	11,561	(296)	(8,084)	804	2,377	0	549	6,199	6,213	535
% of Total Obligation	1438.5%	(36.8%)	(1005.9%)	395.8%	295.8%	0.0%	8.8%	99.8%	108.6%	8.6%

Table 5-9 - PJM Capacity Market load obligation served by non-EDC affiliates: Calendar year 2005

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	18,898	(991)	(16,804)	0	1,103	0	56	8,643	8,355	344
Feb	19,234	(890)	(15,906)	0	2,438	0	157	8,801	8,465	493
Mar	19,271	(1,157)	(15,795)	0	2,319	0	94	8,886	8,467	513
Apr	19,268	(1,275)	(15,824)	0	2,169	0	(9)	8,878	8,400	469
May	20,502	(1,676)	(16,228)	125	2,473	0	120	8,678	8,275	523
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
Phase 4										
Average	19,165	(1,081)	(16,089)	0	1,995	0	73	8,801	8,421	453
% of Total Obligation	NA	NA	NA	NA	NA	0.0%	0.9%	104.5%	105.4%	5.4%
Phase 5										
Average	23,534	(1,041)	(20,469)	160	1,864	0	151	9,163	8,906	408
% of Total Obligation	14724.6%	(651.3%)	(12806.8%)	1266.5%	1166.5%	0.0%	1.7%	102.9%	104.6%	4.6%
Calendar Year										
Average	22,097	(1,054)	(19,029)	107	1,907	0	126	9,044	8,746	424
% of Total Obligation	20597.9%	(982.7%)	(17737.4%)	1877.8%	1777.8%	0.0%	1.4%	103.4%	104.8%	4.8%

Phase 5

As shown in Figure 5-1 and Table 5-6, during Phase 5, PJM EDCs and their affiliates increased their market share of load obligations in the PJM Capacity Market, averaging 88.4 percent, an increase of 3.4 percent over Phase 4. This increase was attributable to Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. The combined market share for Phase 5 of LSEs not affiliated with any EDC and of non-PJM EDCs and their affiliates averaged 11.6 percent, which was down from the 15.0 percent for Phase 4.

Table 5-7, Table 5-8 and Table 5-9 show that during Phase 5, all market sectors were in net excess positions as they had been in Phase 4. PJM EDCs self-supplied an average of 58.0 percent of their load obligations with their remaining obligations being supplied almost entirely through bilateral contracts with third parties (44.1

percent). While Dominion's integration on May 1 increased the self-supplied average volume from 31,172 MW in April to 49,055 MW in May, the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1 decreased the percentage self-supplied by EDCs. Commonwealth Edison Company (an EDC in the ComEd Control Zone) was the major electric distribution company in this market. Having spun off its generating assets to an affiliate, Exelon Generation Company, LLC (ExGen), the company met its entire capacity obligation through bilateral transactions with this affiliate.[20] (See Table 5-18 for ComEd EDC values.)

As shown in Table 5-11 and Figure 5-2, during Phase 5 unforced capacity and obligations increased with Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Average unforced capacity climbed 39,343 MW to 149,888 MW, an increase of 35.6 percent. Average load obligation increased 39,535 MW or 39.5 percent to 139,736 MW. Capacity resources exceeded capacity obligations in PJM on every day by a daily average of 10,152 MW (7.3 percent of obligations), which was a decrease of 192 MW or 1.9 percent from the average net excess during Phase 4. This decrease was attributable to a decrease in imports and an increase in exports resulting from the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Dominion joining PJM on May 1 had no significant impact on net excess. The increases in unforced capacity and obligation were also attributable to ComEd as well as Dominion.

Table 5-10 - PJM capacity summary (MW): Phase 4

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	119,402	723	118,325	120,586
Unforced Capacity	110,545	761	109,351	111,725
Obligation	100,201	94	99,944	100,353
Sum of Excess	10,345	679	9,226	11,442
Sum of Deficiency	1	8	0	39
Net Excess	10,344	681	9,226	11,442
Imports	5,855	359	5,558	6,461
Exports	3,953	335	3,397	4,606
Net Exchange	1,902	659	964	2,992
Internal Unit-Specific Transactions	11,788	77	11,737	11,920
Internal Capacity Credit Transactions	80,092	1,071	78,740	82,011
Total Internal Bilateral Transactions	91,880	1,098	90,492	93,748
Daily Capacity Credits	1,427	91	1,070	1,675
Monthly Capacity Credits	900	370	651	1,523
Multimonthly Capacity Credits	3,322	326	2,810	3,639
All Capacity Credits	5,649	153	5,076	5,937
ALM Credits	1,654	4	1,653	1,669

20 Exelon Corporation, Annual Report (Form 10-K), at 6 (February 23, 2005).

Table 5-11 - PJM capacity summary (MW): Phase 5

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	160,322	7,769	139,942	163,951
Unforced Capacity	149,888	7,644	129,869	153,746
Obligation	139,736	8,026	118,680	143,260
Sum of Excess	10,152	825	8,665	11,270
Sum of Deficiency	0	0	0	0
Net Excess	10,152	825	8,665	11,270
Imports	4,208	609	3,728	5,665
Exports	4,856	701	3,618	5,746
Net Exchange	(648)	1,084	(1,655)	2,047
Internal Unit-Specific Transactions	17,540	2,185	11,920	19,064
Internal Capacity Credit Transactions	133,057	13,152	98,520	140,859
Total Internal Bilateral Transactions	150,597	15,277	110,440	158,940
Daily Capacity Credits	1,560	373	1,025	2,455
Monthly Capacity Credits	1,221	253	699	1,539
Multimonthly Capacity Credits	4,111	306	3,639	4,497
All Capacity Credits	6,892	633	6,035	8,103
ALM Credits	1,993	130	1,653	2,065

External and Internal Capacity Transactions

PJM capacity resources may be traded bilaterally within and outside of PJM.

External Capacity Transactions

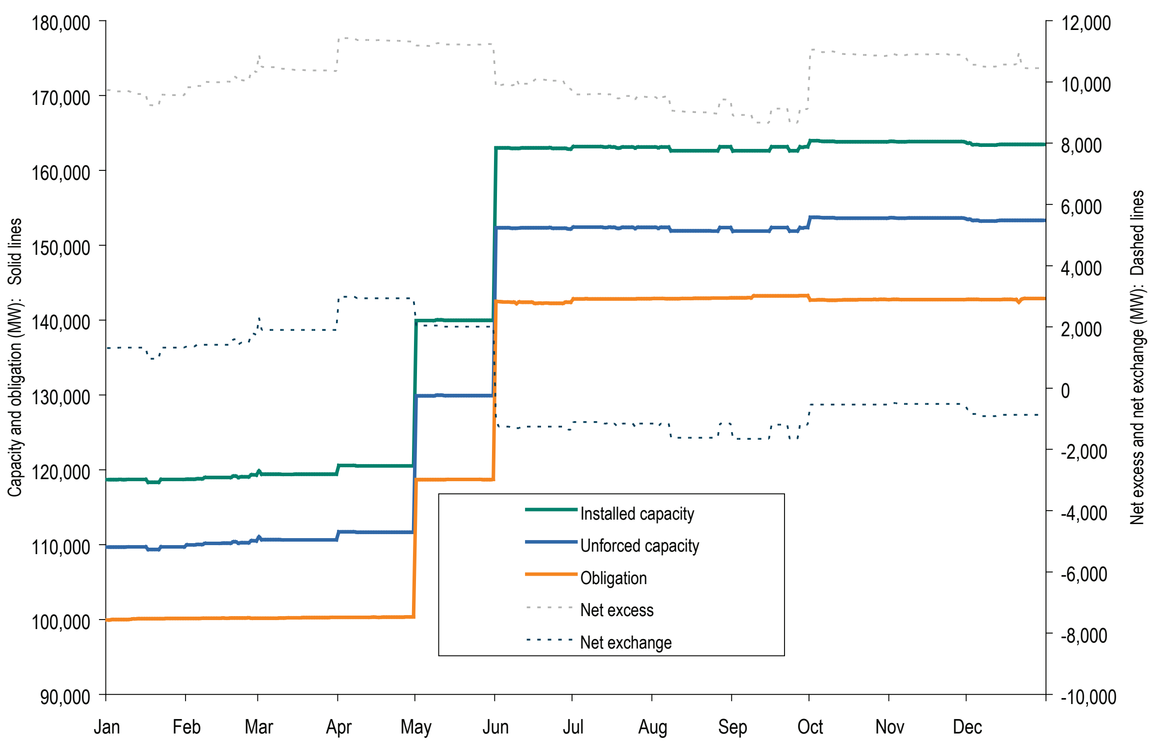
External bilateral transactions include imports of capacity resources from other control areas and exports of capacity resources to control areas outside of PJM.[21] Net exchange is equal to imports less exports.

Phase 4

As shown in Table 5-10 and Figure 5-3, Capacity Market participants' external purchases (imports) of capacity resources were relatively flat through Phase 4, averaging 5,855 MW, which was a decrease of 537 MW or 8.4 percent from the average of 6,392 MW for Phase 3.

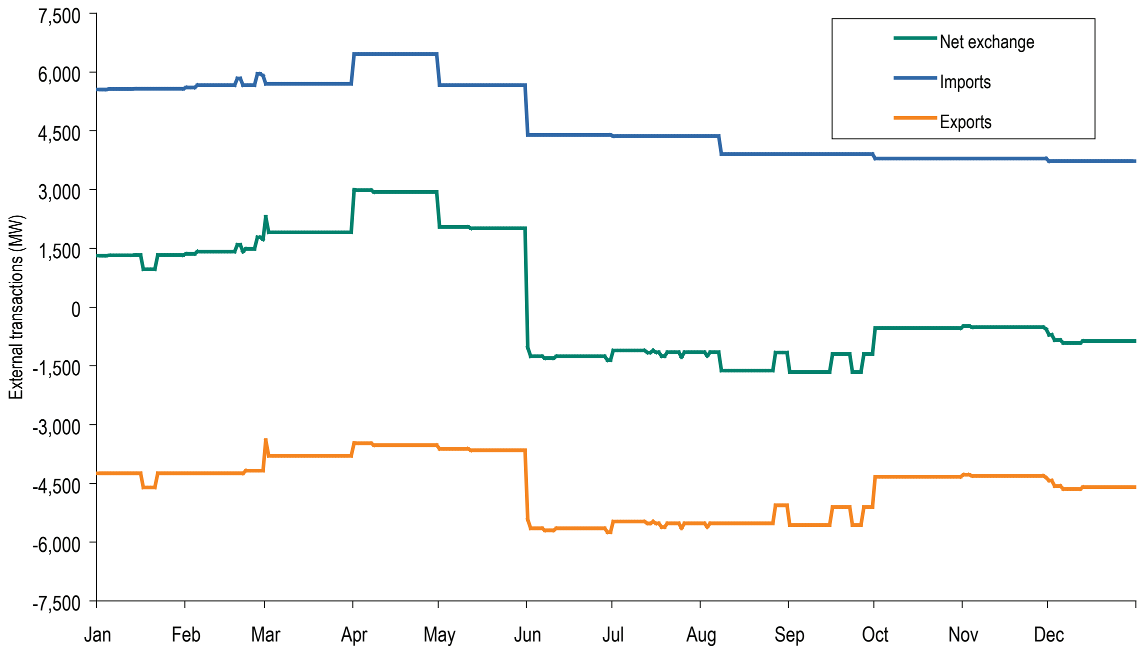
During Phase 4, an average of 3,953 MW of capacity resources was exported from the PJM Capacity Market, which was an increase of 742 MW or 23.1 percent from the average of 3,211 MW for Phase 3. The result was an average net exchange of 1,902 MW of capacity resources for Phase 4, which was a decrease of 1,279 MW or 40.2 percent from the average net exchange of 3,181 MW for Phase 3.

Figure 5-2 - Capacity obligation for the PJM Capacity Market: Calendar year 2005



21 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 2005



Phase 5

Dominion's integration into PJM on May 1 had no significant impact on imports, exports or net exchange. However, the impact of the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1 was significant. What had been exports from the ComEd Capacity Market and imports into PJM became internal transactions. What had been exports from the ComEd Capacity Market into control areas other than PJM were added to total PJM exports. As a result, imports into the PJM market declined; exports from the PJM market increased (i.e., values became more negative), and on June 1 net exchange fell by 3,043 MW, which was the sum of the two changes.[22] (See Figure 5-3.)

Capacity owners' external purchases (imports) of capacity resources during Phase 5 averaged 4,208 MW, which was a decrease of 1,647 MW or 28.1 percent from the import average for Phase 4. (See Table 5-11 and Figure 5-3.)

During Phase 5, an average of 4,856 MW of capacity resources was exported from the PJM Capacity Market, which was an increase of 903 MW or 22.8 percent from the export average for Phase 4. The result was an average net exchange of -648 MW of capacity resources for Phase 5, which was a decrease of 2,550 MW or 134.1 percent from the average net exchange of 1,902 MW for Phase 4.

22 This MW value is the daily change between May 31 and June 1. Daily changes are only reflected in figures. Tables generally show period averages or values for specific dates.

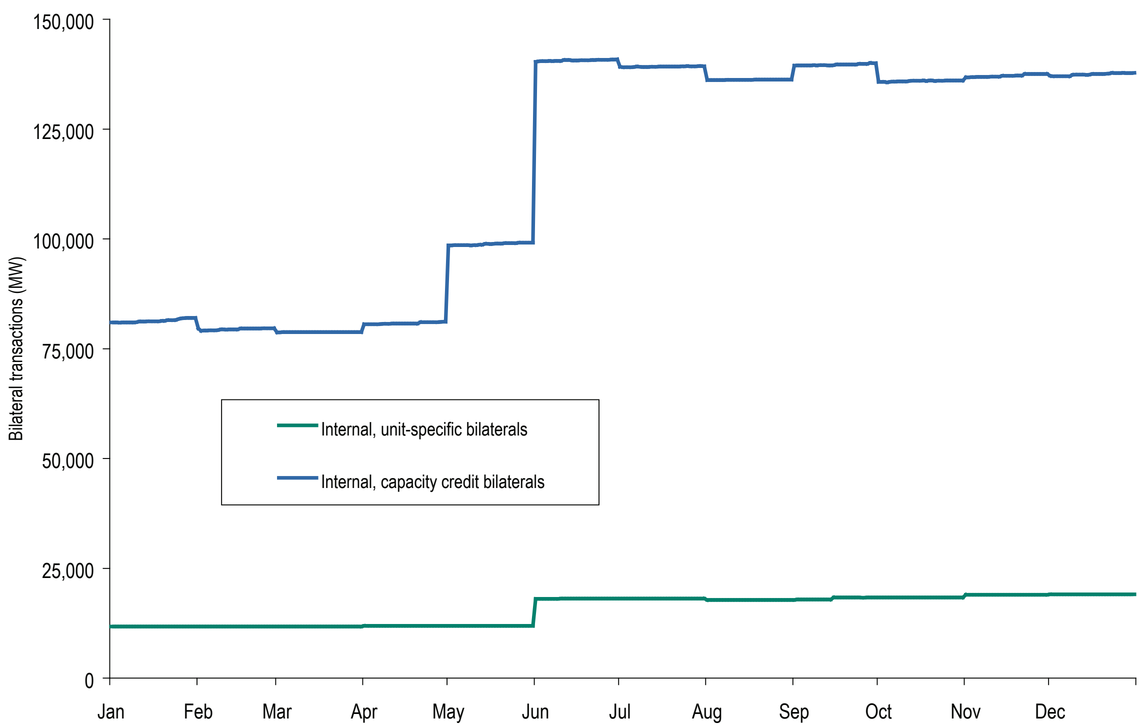
Internal Bilateral Transactions

Internal bilateral transactions are agreements between two parties for the buying and selling of capacity credits within PJM.[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 traded multiple times between parties with the result that transaction volume can exceed obligation.

Phase 4

During Phase 4, internal, unit-specific transactions for the PJM Capacity Market averaged 11,788 MW, which was a decrease of 809 MW or 6.4 percent from the average of 12,597 MW for Phase 3. (See Table 5-10 and Figure 5-4.) Internal capacity credit transactions in Phase 4 averaged 80,092 MW, which was an increase of 15,521 MW or 24.0 percent from the average of 64,571 MW for Phase 3. Total internal bilateral transactions in Phase 4 averaged 91,880 MW, an increase of 14,712 MW or 19.1 percent from the 77,168 MW average for Phase 3.

Figure 5-4 - Internal bilateral PJM Capacity Market transactions: Calendar year 2005



23 As of December 31, 2005, only volumes from internal bilateral transactions are reported to PJM. Pricing data are not required from member companies.

Phase 5

During Phase 5, PJM's internal bilateral transactions rose. As noted above, the impact of the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1 was significant. What had been exports from the ComEd Capacity Market and imports into PJM became internal transactions. The increase in internal bilateral transactions on June 1 was 47,334 MW.[24] As a result, total internal bilateral transactions in Phase 5 averaged 150,597 MW, which was an increase of 58,717 MW or 63.9 percent from the Phase 4 average.

Internal, unit-specific transactions for the PJM Capacity Market averaged 17,540 MW, which was an increase of 5,752 MW or 48.8 percent from the average for Phase 4. (See Table 5-11 and Figure 5-4.) Internal capacity credit transactions in Phase 5 averaged 133,057 MW, an increase of 52,965 MW or 66.1 percent from the Phase 4 average.

Active Load Management (ALM) Credits

Phase 4

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.

During Phase 4, ALM credits in the PJM Capacity Market averaged 1,654 MW, down less than 1 percent from 1,662 MW in Phase 3. (See Table 5-10.)

Phase 5

During Phase 5, ALM credits in the PJM Capacity Market averaged 1,993 MW, an increase of 339 MW or 20.5 percent from Phase 4. This increase was attributable to the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1, 2005, as the mandatory interruptible load (MIL) credits in ComEd were converted to ALM credits in PJM. (See Table 5-11.)

24 This MW value is the daily change between May 31 and June 1. Daily changes are only reflected in figures. Tables generally show period averages or values for specific dates.

Market Performance in the PJM Capacity Market

Capacity Credit Market Volumes and Prices

Phase 4

During 2005, PJM operated Daily, Monthly and Multimonthly Capacity Credit Markets. Figure 5-5 and Table 5-12 show prices and volumes for the calendar year 2005 in PJM's Daily and longer term Capacity Credit Markets. During Phase 4, the Daily Capacity Credit Market averaged 1,427 MW of transactions, representing 1.4 percent of the period's 100,201 MW average capacity obligation. The Phase 4 average transaction volume was 441 MW greater than the Phase 3 average of 986 MW, which had been 1.0 percent of the average capacity obligations for Phase 3. The Monthly and Multimonthly Capacity Credit Markets averaged 4,222 MW of transactions, which was 4.2 percent of the average capacity obligations for Phase 4 and 447 MW higher than the Phase 3 average of 3,775 MW, which was 3.8 percent of the average capacity obligations for Phase 3.

The volume-weighted, average price for Phase 4 was $0.04 per MW-day in the Daily Capacity Credit Market and $10.32 per MW-day in the Monthly and Multimonthly Capacity Credit Markets. The volume-weighted, average price for all Capacity Credit Markets was $7.72 per MW-day.[25] Prices in the Daily Capacity Credit Market during Phase 4 were $0.36 lower than the Phase 3 price of $0.40. Prices in the Monthly and Multimonthly Markets were $2.85 lower than the Phase 3 price of $13.17.

Phase 5

The PJM Daily Capacity Credit Market averaged 1,560 MW of transactions, or 1.1 percent of the average capacity obligations for Phase 5. (See Figure 5-5 and Table 5-12.) Trading in the Daily Capacity Credit Market increased by 133 MW compared to activity in Phase 4. The PJM Monthly and Multimonthly Capacity Credit Markets averaged 5,332 MW of transactions, or 3.8 percent of the average capacity obligations for Phase 5. Trading in the Monthly and Multimonthly Capacity Credit Markets increased by 1,110 MW compared to activity in Phase 4.

The volume-weighted, average price for Phase 5 was $0.21 per MW-day in the Daily Capacity Credit Market and $7.01 per MW-day in the Monthly and Multimonthly Capacity Credit Markets. The volume-weighted, average price for all Capacity Credit Markets was $5.47 per MW-day. Prices in the Daily Capacity Credit Market during Phase 5 were $0.17 higher than Phase 4, while prices in the Monthly and Multimonthly Markets were $3.31 lower for the period.

Calendar Years 1999 through 2005

Figure 5-6 and Table 5-13 show prices and volumes in PJM's Daily and longer term Capacity Credit Markets from June 1999 through December 2005.[26] Since the interval system was introduced in July 2001, overall volume in the Capacity Credit Markets 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

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

obligation traded in the PJM Daily Capacity Market has declined while the share of load obligation traded in Monthly and Multimonthly Capacity Markets has increased. Daily Capacity Market volume declined from 2.5 percent of average obligation in 2000 to 1.2 percent in 2005. Monthly and Multimonthly Capacity Market volume increased from 3.0 percent of obligation in 2000 to 3.9 percent of average obligation in 2005.

Figure 5-5 - PJM Daily and Monthly Capacity Credit Market (CCM) performance: Calendar year 2005

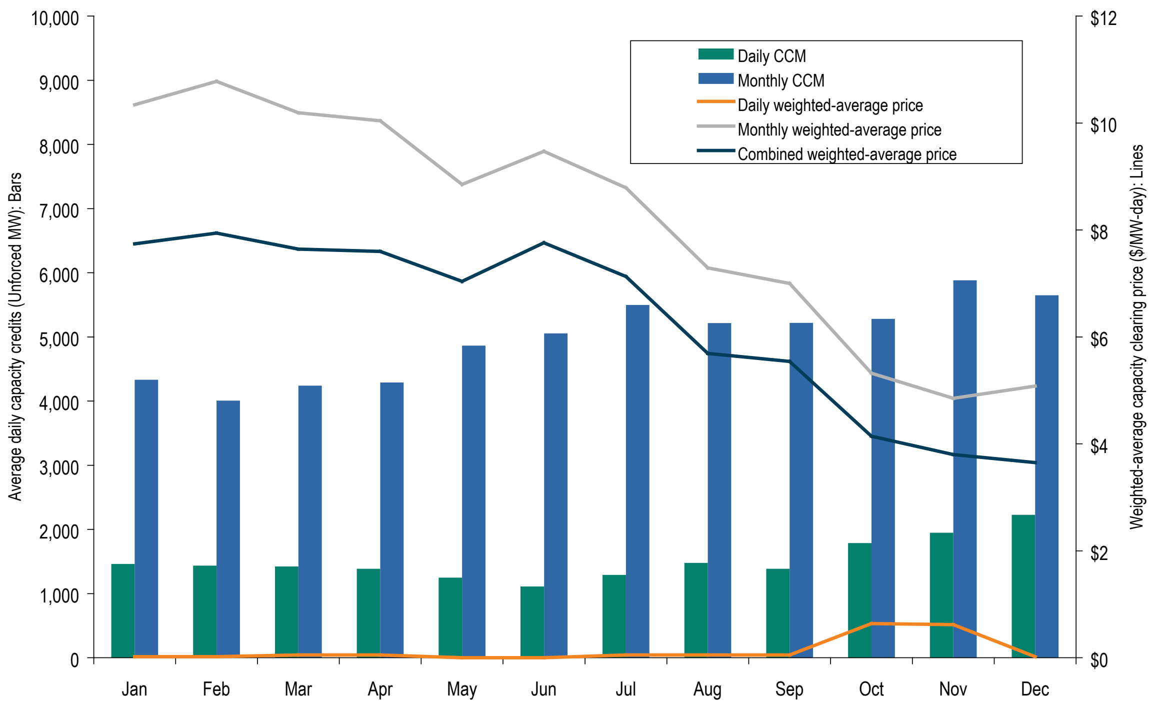


Table 5-12 - PJM Capacity Credit Markets: Calendar year 2005

	Average Daily Capacity Credits (MW)			Weighted-Average Price ($ per MW-day)		
	Daily Capacity Credit Market	Monthly and Multimonthly Capacity Credit Market	Combined Markets	Daily Capacity Credit Market	Monthly and Multimonthly Capacity Credit Market	Combined Markets
Jan	1,461	4,333	5,794	$0.02	$10.34	$7.74
Feb	1,436	4,006	5,442	$0.02	$10.78	$7.94
Mar	1,423	4,240	5,663	$0.05	$10.19	$7.64
Apr	1,387	4,290	5,677	$0.05	$10.04	$7.60
May	1,249	4,864	6,113	$0.00	$8.85	$7.04
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						
Phase 4	1,427	4,222	5,649	$0.04	$10.32	$7.72
Phase 5	1,560	5,332	6,892	$0.21	$7.01	$5.47
Calendar Year	1,516	4,968	6,484	$0.15	$7.94	$6.12

Figure 5-6 - PJM Daily and Monthly Capacity Credit Market (CCM) performance: June 1999 through December 2005

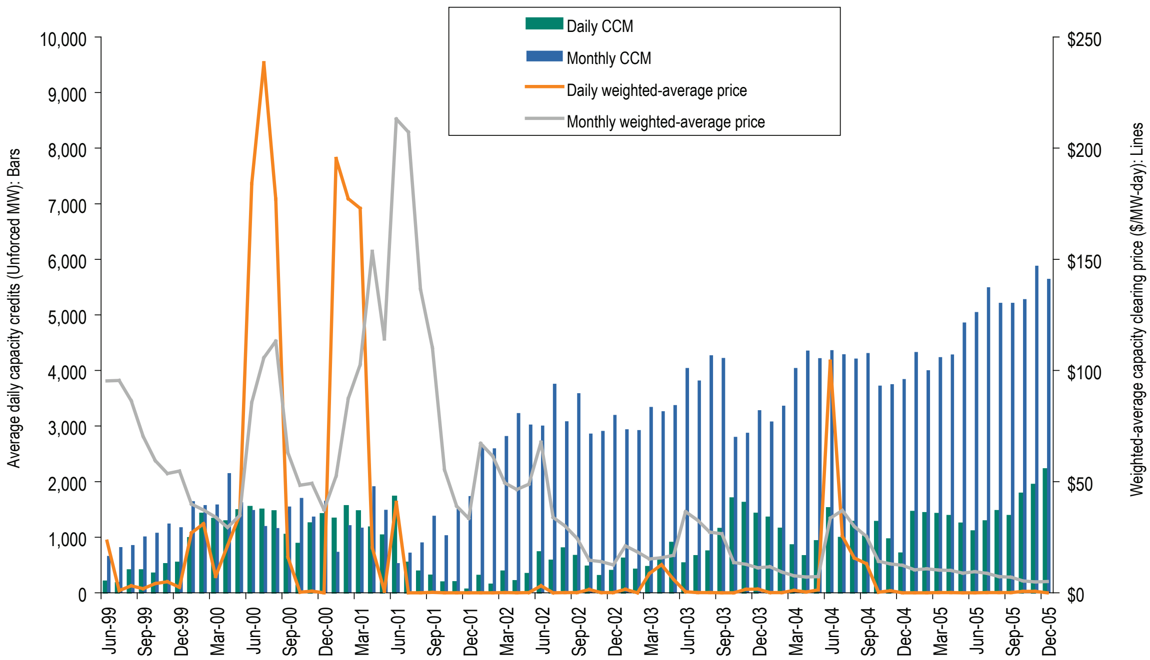


Table 5-13 - PJM Capacity Credit Markets: Calendar years 1999[27] through 2005[28]

	Average Daily Capacity Credits						Weighted-Average Price ($ per MW-day)		
	Daily Capacity Credit Market (MW)	Percent of Obligation	Monthly and Multimonthly Capacity Credit Market (MW)	Percent of Obligation	Combined Markets (MW)	Percent of Obligation	Daily Capacity Credit Market	Monthly and Multimonthly Capacity Credit Market	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

27 Beginning June 1, 1999, when the PJM Capacity Credit Market began to use unforced capacity.

28 Prior state of the market reports showed weighted-average 1999 prices of $3.63 (daily), $70.66 (monthly and multimonthly) and $52.86 (combined). Corrected values are shown here.

Market Structure for the ComEd Capacity Market

The ComEd Control Area[29] was integrated into PJM on May 1, 2004, but the ComEd Capacity Market was not implemented until June 1, 2004. During May 2004, capacity obligations in the ComEd Control Area were satisfied wholly by Commonwealth Edison Company according to the procedures PJM established. The ComEd Capacity Market operated under rules based on installed capacity with obligation fixed on a monthly basis. There was no daily capacity credit market. The interim ComEd Capacity Market structure included three intervals: June to September 2004; October to December 2004; and January to May 2005. The capacity obligation for each interval was based on the forecasted interval peak and the installed reserve margin, both of which were recalculated for each interval.[30] These rules remained in effect through May 31, 2005, when the ComEd Control Zone became part of the PJM Capacity Market.[31]

Ownership Concentration

For the period June 1, 2004, through May 31, 2005, the MMU analyzed market concentration ratios and pivotal supplier measures for the ComEd Market.

June 2004 through May 2005

Structural analysis[32] indicates that from June 2004 through May 2005, ComEd's Monthly and Multimonthly Capacity Credit Markets exhibited high levels of concentration.[33] HHIs for Monthly and Multimonthly Capacity Credit Markets averaged 5907, with a maximum of 10000 and a minimum of 2253, while all 60 of the auctions had an HHI greater than 1800. (See Table 5-14.) The highest market share for any entity in any auction was 100.0 percent. One entity owned or controlled almost 60 percent of total capacity in the ComEd Control Zone.

Table 5-14 - ComEd Capacity Market HHI: June 2004 through May 2005

Statistic	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	NA	5907
Minimum	NA	2253
Maximum	NA	10000
Highest Market Share	NA	100.0%
# Auctions	NA	60
# Auctions with HHI >1800	NA	60
% Auctions with HHI >1800	NA	100.0%

29 ComEd was known as the ComEd Control Area from May 1, 2004, until October 1, 2004, when it became the ComEd Control Zone. These terms are used interchangeably throughout this section.

30 "Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone during the Interim Period," "PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region" (December 20, 2004), pp. 48A – 48D.

31 See Appendix E, "Capacity Markets."

32 See Section 2, "Energy Market, Part 1," for a discussion of concentration ratios and the HHI.

33 ComEd Capacity Market results are reported by the time period during which the auction was run and not by the time period to which the auction applies.

Table 5-15 - ComEd Capacity Market residual supply index (RSI): June 2004 through May 2005

Statistic	Daily Market RSI	Monthly and Multimonthly Market RSI
Average	NA	2.76
Minimum	NA	0.00
Maximum	NA	25.60
# Auctions	NA	60
# Auctions with RSI < 1.0	NA	26
% Auctions with RSI < 1.0	NA	43.3%
# Auctions with <= 3 Pivotal Suppliers	NA	58
% Auctions with <= 3 Pivotal Suppliers	NA	96.7%

Table 5-15 shows RSI values for the Monthly and Multimonthly Capacity Credit Market Auctions for the ComEd Capacity Market. The high average RSI value of 2.76 and the high maximum RSI value resulted from the relatively small volumes bid in Capacity Credit Market Auctions. Of 60 capacity auctions held for ComEd, 26 (43.3 percent) had RSI values of less than 1.0, meaning that a single supplier was pivotal in these auctions, while 58 of the auctions (96.7 percent) had three or fewer jointly pivotal suppliers.

Total Capacity

The market structure for total capacity in the aggregate ComEd Capacity Market is shown for specific dates in Table 5-16. The analysis uses capacity ownership as of the beginning of each interval (June 1, 2004, October 1, 2004, and January 1, 2005) and on May 31, 2005 (the last day of a separate ComEd Capacity Market). The analysis of total capacity is included as it represents conditions in the Capacity Market without regard to whether capacity was sold in bilateral or PJM-operated markets. This evaluation is relevant because only about 6 percent of ComEd Control Zone capacity was traded in PJM-operated markets.

The analysis shows that on these dates, capacity resources exceeded capacity obligations in the ComEd Capacity Market. The decrease in obligation of 8,497 MW on October 1 was the result of the lower interval peak for the October to December period. The obligation increased by 520 MW on January 1 to reflect the higher interval peak of the January to May period. Installed capacity decreased by 4,916 MW over this period with retirement of capacity resources accounting for 3,466 MW and increased exports offset by a small increase in imports accounting for the remainder. (See Table 5-16.) The retirement of capacity resources by the two largest capacity owners in the ComEd Capacity Market led to a decrease in market concentration reflected in the reduction of the HHI from 4525 to 4070 and a decrease in the maximum market share from 64.2 percent to 59.8 percent. One pivotal supplier existed throughout the period.

Table 5-16 - ComEd Capacity Market: June 2004 through May 2005

	01-Jun	01-Oct	01-Jan	31-May
Obligation (MW)	25,162	16,665	17,185	17,185
Installed Capacity (MW)	28,999	27,740	24,676	24,083
HHI	4525	4404	3978	4070
Highest Market Share	64.2%	63.3%	58.9%	59.8%
RSI	0.41	0.59	0.59	0.56
Pivotal Suppliers	1	1	1	1

Supply and Demand

June 2004 through May 2005

From June 2004 through May 2005, ComEd EDCs together had an 81.6 percent market share of load obligation in the ComEd Capacity Market. (See Table 5-17.) All customers in the ComEd Control Zone were eligible for retail access although eligible residential customers did not switch to retail access service in 2005.[34] Instead, switching activity was limited to commercial, industrial and governmental customers.[35] Switching was affected by a number of factors. The local utility's bundled rates have been fixed at, or below, 1997 levels since passage of the Illinois Electric Service Customer Choice and Rate Relief Law of 1997.[36] Bundled rates will remain frozen by legislative mandate until the end of 2006.[37] In addition, any customer switching from bundled service to a retail choice option must pay a transition charge on energy bought from alternative suppliers. Transition charges will end in the ComEd service territory on December 31, 2006.[38]

During the period under discussion, load-serving entities could meet their ComEd Control Zone load obligations through self-supply,[39] the ComEd Capacity Credit Market or bilateral contracts with third parties. Reliance on these options varied by market sector. (See Table 5-18, Table 5-19 and Table 5-20.)[40] From June 2004 through May 2005, ComEd EDCs self-supplied an average of only 0.1 percent of their load obligations, with their remaining obligations supplied almost entirely through bilateral contracts with third parties (112.4 percent). Commonwealth Edison Company (an EDC in the ComEd Control Zone) was the major electric distribution company in this market. Having spun off its generating assets to an affiliate, ExGen (included among ComEd Control Zone EDC affiliates), the company met its entire capacity obligation through bilateral transactions with this affiliate. Until October 1, 2004, ComEd EDCs, on average, met their load obligation almost exactly. When EDC load obligations decreased on October 1, EDC purchases of capacity credits through bilateral contracts decreased as well, but by less than the reduction in their load obligations, resulting in a net excess position. All generating affiliate sectors, which had no load obligations, were net capacity credit sellers and remained in net excess positions. All marketing affiliate sectors, which were net capacity credit buyers, purchased more capacity credits than their obligations, but had lower net excess positions, in MW, than the generating affiliate sectors.

34 See Illinois Commerce Commission, "Competition in Illinois Retail Electric Markets in 2004" (April 2005) < http://www.icc.illinois.gov/ec/docs/050401garpt16120b.pdf > (127 KB). In a phone interview on January 6, 2006, ICC staff confirmed that switching remains limited to nonresidential customers.

35 See Illinois Commerce Commission, Electric Switching Statistics (December 2005) < http://www.icc.illinois.gov/ec/docs/dasrcomed.xls > (181 KB).

36 Illinois General Assembly, "Electric Service Customer Choice and Rate Relief Law of 1997," (220 ILCS 5/16-111 (b)).

37 See Illinois Commerce Commission, "Final Report of the Illinois Commerce Commission's Post-2006 Initiative" (December 2004) < http://www.icc.illinois.gov/ec/docs/041208ecPostRptExe.pdf > (85 KB).

38 See Illinois Commerce Commission, "Plug In Illinois"< http://www.icc.illinois.gov/pluginillinois/Timeline.asp >.

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

40 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 5-17 - ComEd Capacity Market load obligation served: June 2004 through May 2005

	Average Obligation (MW)							
	ComEd EDCs	ComEd EDC Generating Affiliates	ComEd EDC Marketing Affiliates	Non ComEd EDC Generating Affiliates	Non ComEd EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Jun-04	20,503	0	3,040	0	1,520	0	99	25,162
Jul-04	20,601	0	2,937	0	1,530	0	94	25,162
Aug-04	20,847	0	2,716	0	1,510	0	88	25,161
Sep-04	20,555	0	3,001	0	1,519	0	88	25,163
Oct-04	13,589	0	2,006	0	1,012	0	58	16,665
Nov-04	13,573	0	2,031	0	1,016	0	46	16,666
Dec-04	13,582	0	2,024	0	1,014	0	45	16,665
Jan-05	13,924	0	2,143	0	1,069	0	49	17,185
Feb-05	13,945	0	2,135	0	1,056	0	49	17,185
Mar-05	13,938	0	2,141	0	1,058	0	49	17,186
Apr-05	13,890	0	2,160	0	1,085	0	49	17,184
May-05	13,880	0	2,153	0	1,087	0	65	17,185
Average	16,075	0	2,374	0	1,207	0	65	19,721
% of Total Obligation	81.6%	0.0%	12.0%	0.0%	6.1%	0.0%	0.3%	100.0%

Table 5-18 - ComEd Capacity Market load obligation served by ComEd EDCs and affiliates: June 2004 through May 2005

	ComEd EDCs					ComEd EDC Generating Affiliates					ComEd EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun-04	0	10	20,493	20,503	0	13,888	212	(13,369)	0	731	0	715	2,326	3,040	1
Jul-04	0	10	20,591	20,601	0	13,888	212	(13,657)	0	443	0	714	2,227	2,937	4
Aug-04	0	10	20,837	20,847	0	13,888	212	(13,650)	0	450	0	635	2,209	2,716	128
Sep-04	0	10	20,546	20,555	1	13,888	212	(13,517)	0	583	0	675	2,328	3,001	2
Oct-04	21	(9)	16,531	13,589	2,954	13,888	(88)	(11,478)	0	2,322	0	642	1,835	2,006	471
Nov-04	21	(9)	16,512	13,573	2,951	13,888	(88)	(11,458)	0	2,342	0	645	1,860	2,031	474
Dec-04	21	(9)	16,522	13,582	2,952	13,888	(88)	(11,522)	0	2,278	0	645	1,859	2,024	480
Jan-05	21	(11)	16,941	13,924	3,027	13,888	(350)	(13,318)	0	220	0	752	1,859	2,143	468
Feb-05	21	(11)	16,967	13,945	3,032	13,932	(325)	(13,323)	0	284	0	801	1,798	2,135	464
Mar-05	21	(11)	16,959	13,938	3,031	13,932	(275)	(13,249)	0	408	0	852	1,755	2,141	466
Apr-05	21	(11)	16,901	13,890	3,021	13,907	(330)	(13,299)	0	278	0	856	2,054	2,160	750
May-05	21	(10)	16,888	13,880	3,019	13,882	(340)	(13,242)	0	300	0	849	2,053	2,153	749
Average	14	(3)	18,060	16,075	1,996	13,896	(85)	(12,920)	0	891	0	731	2,014	2,374	371
% of Total Obligation	0.1%	0.0%	112.4%	112.5%	12.5%	NA	NA	NA	NA	NA	0.0%	30.8%	84.8%	115.6%	15.6%

Table 5-19 - ComEd Capacity Market load obligation served by non-ComEd EDC affiliates: June 2004 through May 2005

	Non-ComEd EDC Generating Affiliates					Non-ComEd EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun-04	12,079	(1,120)	(8,353)	0	2,606	0	410	1,262	1,520	152
Jul-04	10,456	(1,005)	(8,579)	0	872	0	405	1,126	1,530	1
Aug-04	10,456	(1,015)	(8,474)	0	967	0	494	1,447	1,510	431
Sep-04	10,456	(1,034)	(8,585)	0	837	0	424	1,467	1,519	372
Oct-04	10,456	(520)	(6,907)	0	3,029	0	220	1,767	1,012	975
Nov-04	10,580	(510)	(7,207)	0	2,863	0	190	1,773	1,016	947
Dec-04	10,755	(510)	(7,207)	0	3,038	0	195	1,776	1,014	957
Jan-05	8,765	(470)	(5,623)	0	2,672	0	279	1,455	1,069	665
Feb-05	8,765	(470)	(6,123)	0	2,172	0	231	1,604	1,056	779
Mar-05	8,596	(470)	(5,973)	0	2,153	0	197	1,454	1,058	593
Apr-05	8,596	(520)	(5,973)	0	2,103	0	225	1,173	1,085	313
May-05	8,596	(520)	(5,994)	0	2,082	0	220	1,170	1,087	303
Average	9,883	(681)	(7,086)	0	2,116	0	291	1,455	1,207	539
% of Total Obligation	NA	NA	NA	NA	NA	0.0%	24.1%	120.6%	144.7%	44.7%

Table 5-20 - ComEd Capacity Market load obligation served by non-EDC affiliates: June 2004 through May 2005

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun-04	3,375	(227)	(2,800)	0	348	0	0	99	99	0
Jul-04	3,375	(337)	(2,750)	0	288	0	0	94	94	0
Aug-04	3,375	(337)	(3,030)	0	8	0	0	88	88	0
Sep-04	3,375	(287)	(3,030)	0	58	0	0	88	88	0
Oct-04	3,375	(245)	(2,725)	0	405	0	0	71	58	13
Nov-04	3,375	(228)	(2,660)	0	487	0	0	55	46	9
Dec-04	3,375	(233)	(2,720)	0	422	0	0	55	45	10
Jan-05	3,375	(200)	(2,745)	0	430	0	0	59	49	10
Feb-05	3,375	(227)	(2,745)	0	403	0	0	59	49	10
Mar-05	3,375	(293)	(2,695)	0	387	0	0	59	49	10
Apr-05	3,375	(220)	(2,745)	0	410	0	0	59	49	10
May-05	3,375	(200)	(2,745)	0	430	0	0	79	65	14
Average	3,375	(253)	(2,783)	0	339	0	0	72	65	7
% of Total Obligation	NA	NA	NA	NA	NA	0.0%	0.0%	111.4%	111.4%	11.4%

The level of resources available to satisfy the capacity obligation in the ComEd Capacity Market during any month reflected the addition of new resources, the retirement of old resources and the importing or exporting of capacity resources.

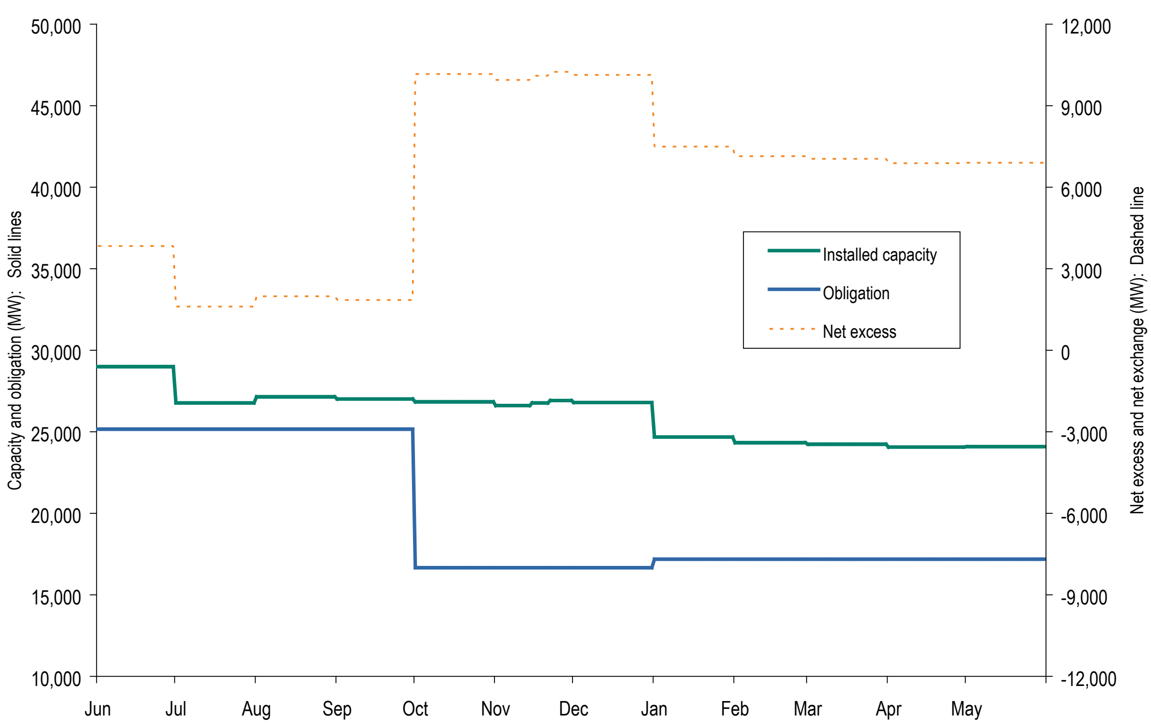
Net excess equals total capacity resources less capacity obligation. Since obligation includes expected load plus a reserve margin, a net excess of zero or greater is consistent with established reliability objectives. As shown in Table 5-21 and Figure 5-7, for June 2004 through May 2005, the ComEd Capacity Credit Market had an average net excess of 6,261 MW, or 31.7 percent of average obligation for the period.[41]

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

Table 5-21 - ComEd capacity summary (MW): June 2004 through May 2005

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	25,980	1,549	24,068	28,999
Unforced Capacity	25,980	1,549	24,068	28,999
Obligation	19,721	3,867	16,665	25,163
Sum of Excess	6,261	3,094	1,609	10,249
Sum of Deficiency	0	0	0	0
Net Excess	6,261	3,094	1,609	10,249
Imports	481	117	360	651
Exports	1,669	581	747	2,464
Net Exchange	(1,188)	487	(1,831)	(343)
Internal Unit-Specific Transactions	5,150	1,441	3,400	6,775
Internal Capacity Credit Transactions	25,836	2,085	23,659	29,025
Total Internal Bilateral Transactions	30,986	3,275	28,061	35,801
Daily Capacity Credits	0	0	0	0
Monthly Capacity Credits	126	66	10	221
Multimonthly Capacity Credits	1,103	226	895	1,457
All Capacity Credits	1,229	251	949	1,629
MIL Credits	224	86	153	346

Figure 5-7 - Capacity obligation for the ComEd Capacity Market: June 2004 through May 2005



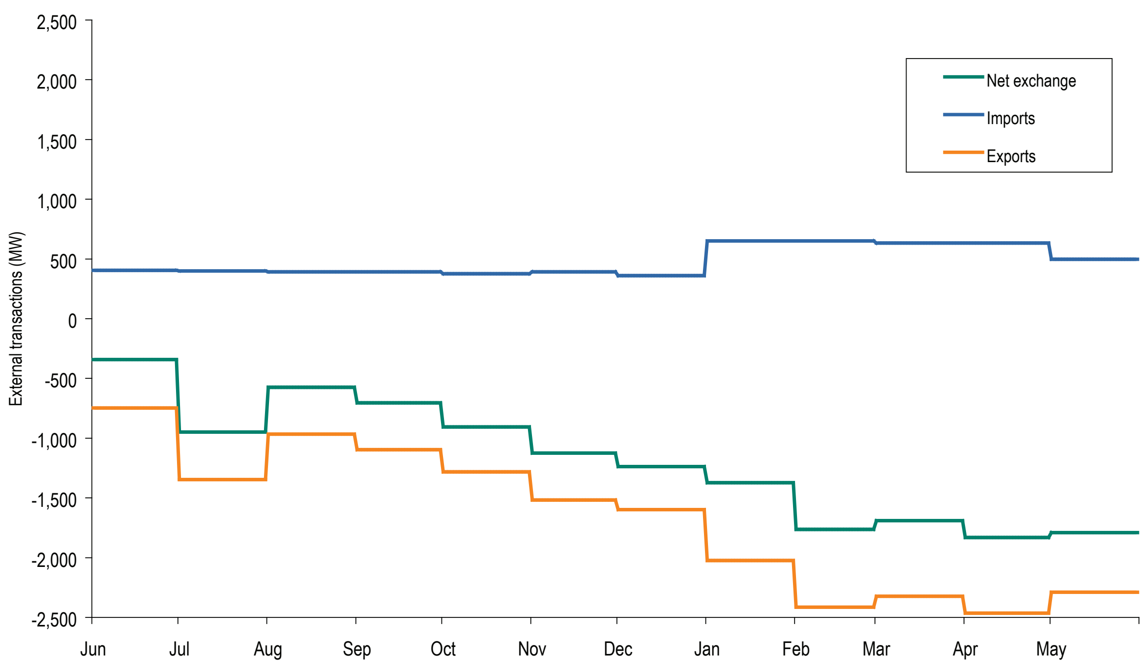
External and Internal Capacity Transactions

ComEd capacity resources were traded bilaterally within and outside of ComEd.

External Bilateral Transactions

External bilateral transactions included imports of capacity resources from other control areas and exports of capacity resources to control areas outside of ComEd. Figure 5-8 presents ComEd's external bilateral capacity transaction data for June 2004 through May 2005. (Table 5-21 also includes summary data on imports and exports.) During this period, the ComEd Control Zone was a net exporter of capacity resources as exports grew from 747 MW on June 1 to 2,289 MW on May 31. Almost half of this increase was attributable to increased exports to the PJM Capacity Market, which rose from 150 MW on June 1 to 875 MW on May 31. With imports remaining relatively constant during this period, this increase in exports led to a decrease in net exchange of 1,448 MW. Net exchange is equal to imports less exports.

Figure 5-8 - External ComEd Capacity Market transactions: June 2004 through May 2005

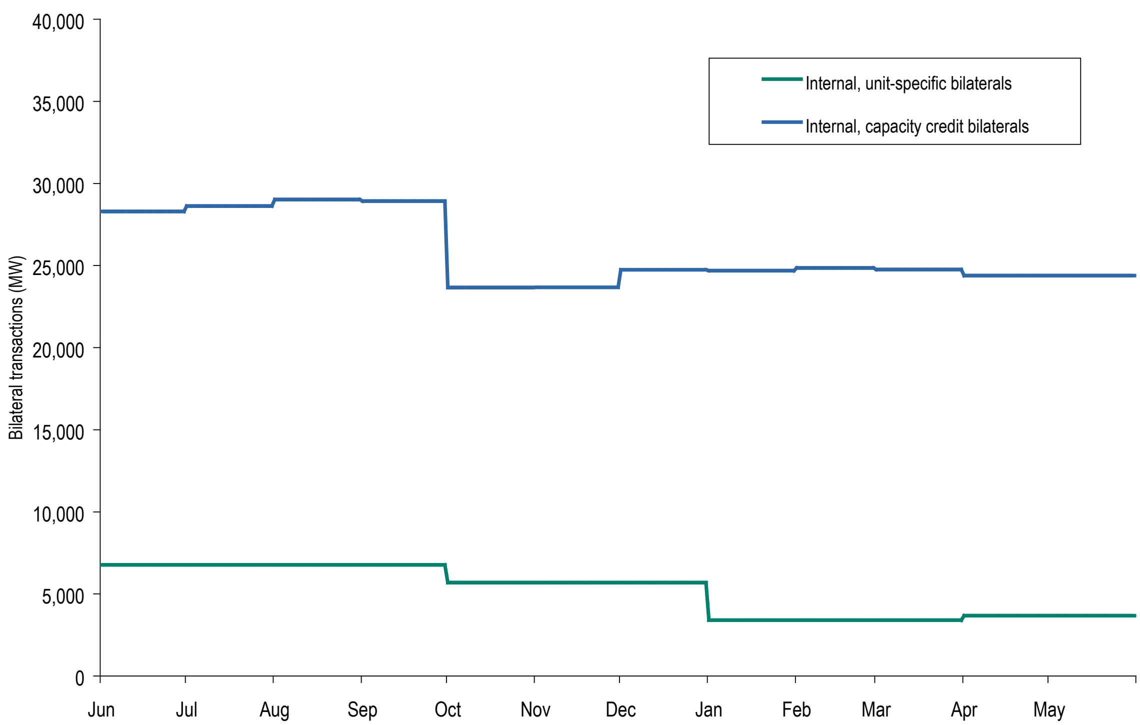


Internal Bilateral Transactions

Internal bilateral transactions are agreements between two parties for the buying and selling of capacity credits within PJM. 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 traded multiple times between parties with the result that transaction volume can exceed obligation.

Figure 5-9 presents data on ComEd's internal bilateral capacity transactions for June 2004 through May 2005. (Table 5-21 also includes summary data on internal bilateral transactions.) The decreases of 1,092 MW in unit-specific bilaterals and of 5,269 MW in capacity credit bilaterals on October 1 were the result of the lower interval peak for the October to December period.

Figure 5-9 - Internal bilateral ComEd Capacity Market transactions: June 2004 through May 2005



Market Performance for the ComEd Capacity Market

Capacity Credit Market Volumes and Prices

Between June 2004 and May 2005, PJM operated 60 Monthly and Multimonthly Capacity Credit Market Auctions to help LSEs satisfy their ComEd Control Zone capacity obligations for the June 2004 to May 2005 capacity planning period.[42] Table 5-21 shows that Monthly and Multimonthly Capacity Credits averaged 1,229 MW, or 6.2 percent of the average capacity obligation for this period.

Table 5-22 shows ComEd Monthly and Multimonthly Capacity Credit Market average daily volumes, which decreased on October 1 as a result of the lower peak for the October through December interval and then increased on January 1 to reflect the higher obligation for the January to May interval. Table 5-22 also shows the ComEd Monthly and Multimonthly Capacity Credit Market prices for June 2004 through May 2005. The volume-weighted, average price was $23.99 with a range from a low of $16.14 per MW-day in May to a high of $32.26 per MW-day in July.

42 See PJM, "NICA Installed Capacity Credit Results" < ftp://ftp.pjm.com/pub/ capacity_credit_market/results/nica/ccmmonthly-nica.csv > (4.8 KB).

While there is no information to support the statement that individual suppliers offered their capacity at a competitive price based on unit costs, and although the market structure in the ComEd Capacity Market was highly concentrated as evidenced by the high HHIs, market performance results were, with the exception of July 2004, less than the $30 per MW-day offer cap that had been proposed by PJM to mitigate market power in the ComEd Capacity Market. The MMU concludes that the ComEd Capacity Market results were reasonably competitive for June 2004 through May 2005.

Table 5-22 - ComEd Capacity Credit Markets: June 2004 through May 2005

	Monthly and Multimonthly Daily Average Volume (MW)	Monthly and Multimonthly Weighted-Average Price ($ per MW-day)
Jun-04	1,507	$29.06
Jul-04	1,525	$32.26
Aug-04	1,584	$28.77
Sep-04	1,629	$28.64
Oct-04	949	$24.43
Nov-04	952	$24.29
Dec-04	957	$24.17
Jan-05	1,031	$19.24
Feb-05	1,086	$18.21
Mar-05	1,138	$17.39
Apr-05	1,167	$16.83
May-05	1,218	$16.14
Average	1,229	$23.99

Generator Performance

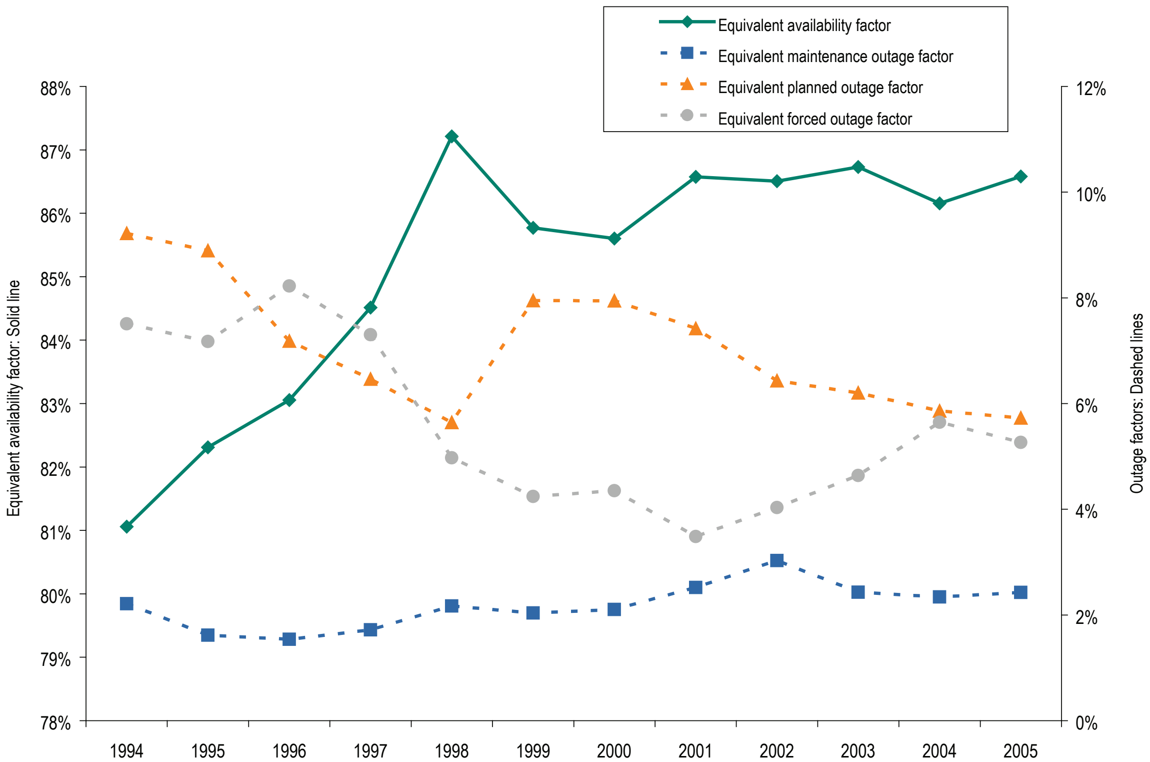
Generator performance can be defined using indices calculated from historical data. Generator performance indices include measures based on total hours in a period (generator performance factors) and measures based on hours when units are needed to operate by the system operator (generator forced outage rates).

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable. 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 that a unit is available to generate at full capacity while the three outage factors include all the hours that a unit is unavailable. The EMOF is the proportion of hours in a year that a unit is unavailable due to maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year that a unit is unavailable due to planned outages and planned deratings. The EFOF is the proportion of hours in a year that a unit is unavailable due to forced outages and forced deratings.

The PJM aggregate[43] EAF increased from 86.2 percent in 2004 to 86.6 percent in 2005.[44] The EFOF decreased by 0.4 percentage points from 2004 to 2005, the EPOF decreased by about 0.1 percentage points and the EMOF increased by about 0.1 percentage points. (See Figure 5-10.) The EAF for all PJM control zones was 87.6 percent in 2005.

Figure 5-10 - PJM equivalent outage and availability factors: Calendar years 1994 to 2005



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.

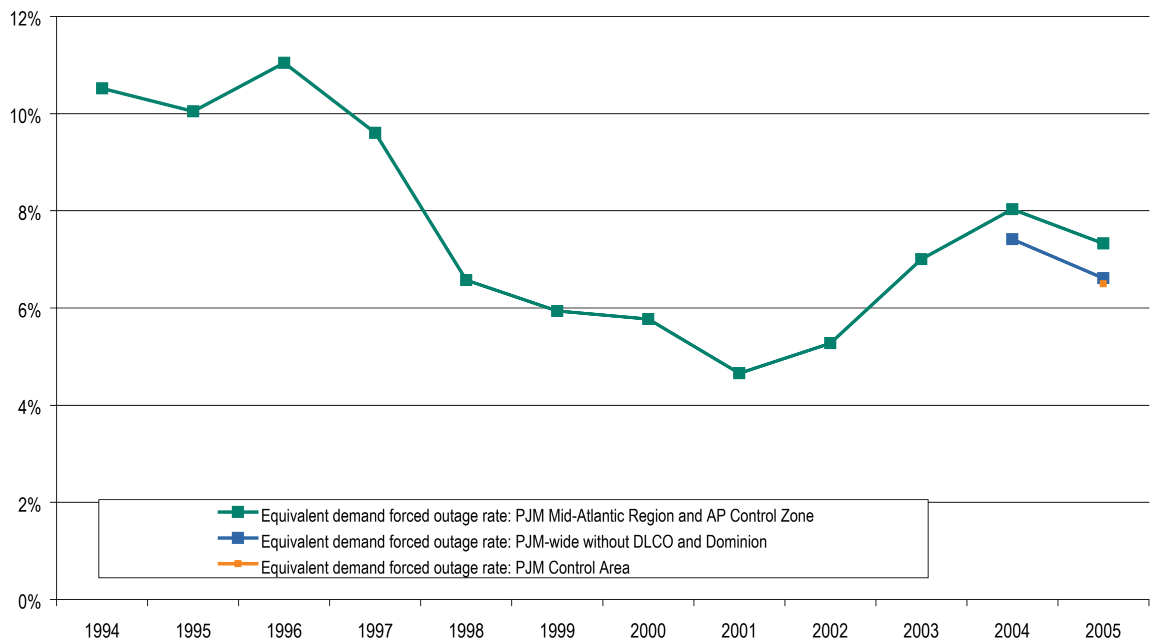
43 The performance factor data include only units from the PJM Mid-Atlantic Region and the AP Control Zone for comparability with prior years' state of the market reports. In order to maintain comparability, units from other control zones that were considered capacity resource imports in prior state of the market reports are also included. Data from the more recently integrated control zones will be included when there are two complete calendar years of data for each control zone.

44 Data are for 12 months ended December 31, 2005, as downloaded from the PJM GADS database on January 24, 2006. Data for the year 2005 may be incomplete as of the download date as corrections can be made at anytime with permission from the PJM GADS administrators.

EFORd calculations use historical data, including equivalent forced outage hours,[45] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[46] Between 1996 and 2001, the average PJM EFORd declined, reaching 4.6 percent in 2001, then increased to 5.2 percent in 2002, 7.0 percent in 2003 and 8.0 percent in 2004 before it again decreased in 2005 to 7.3 percent.[47]

Figure 5-11 shows the average EFORd since 1994 for all units in the PJM Mid-Atlantic Region and AP Control Zone. Figure 5-11 shows separately the average EFORd for 2004 and 2005 for all units in the PJM Mid-Atlantic Region, AP Control Zone, AEP Control Zone and DAY Control Zone. Figure 5-11 also shows separately for 2005 the average EFORd for the entire PJM Control Area including the DLCO and Dominion Control Zones. The 2005 EFORd was 6.5 percent for the entire PJM Control Area.[48]

Figure 5-11 - Trends in PJM equivalent demand forced outage rate (EFORd): Calendar years 1994 to 2005



45 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.

46 See PJM Manual M22, "Generator Resource Performance Indices, Revision 14" (June 1, 2005), Equation 8.

47 Data are for the 12 months ended December 31, 2005, as downloaded from the PJM GADS database on January 24, 2006. Data for the year 2005 may be incomplete as of the download date as corrections can be made at anytime with permission from the PJM GADS administrators.

48 The EFORd is reported for the entire PJM Control Area only for 2005 because data are either not available or are incomplete for the years 1994 through 2003 for the AEP, DAY and ComEd Control Zones and for 1994 through 2004 for the DLCO and Dominion Control Zones. PJM Control Area data for 2004 include seven months of data for the ComEd Control Zone and three months of data for the AEP and DAY Control Zones, consistent with their May 1, 2004, and October 1, 2004, integration dates. PJM Control Area data for 2005 include seven months of data for the Dominion Control Zone and 12 months of data for the DLCO Control Zone consistent with the corresponding May 1, 2005, and January 1, 2005, integration dates. The capacity of generators in these control zones has been prorated based on the number of months of data included.

Components of Change in EFORd

Table 5-23 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.[49] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-23 - Contribution to EFORd for specific unit types (In percentage points): Calendar years 1998 through 2005

Unit Type	1999	2000	2001	2002	2003	2004	2005	Change in 2005 from 2001	Change in 2005 from 2004
Combined Cycle	0.1	0.1	0.1	0.4	0.7	1.1	0.9	0.8	(0.2)
Combustion Turbine	1.5	1.0	0.7	0.7	1.4	1.4	2.1	1.4	0.7
Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.0
Nuclear	0.5	0.6	0.3	0.3	0.4	0.6	0.2	(0.1)	(0.4)
Steam	3.9	3.8	3.5	3.8	4.4	4.8	4.0	0.5	(0.8)
Total	6.0	5.6	4.6	5.2	7.0	8.0	7.3	2.7	(0.7)

The increase in the EFORd of 2.7 percentage points (a 58.7 percent increase) between 2001 and 2005 resulted primarily from combustion turbine units and combined-cycle units which together contributed 2.2 of the 2.7 percentage point increase, or 81 percent of the increase.

The decrease in EFORd of 0.7 percentage points (an 8.8 percent decrease) from 2004 to 2005 resulted primarily from fossil steam and nuclear units offset in part by combustion turbines.[50] Fossil steam units (162 generating units) contributed -0.8 percentage points, nuclear units (13 generating units) contributed -0.4 percentage points, combined-cycle units (60 generating units) contributed -0.2 percentage points. Combustion turbine units (300 generating units) added 0.7 percentage points to partially offset the decreases for other unit types.

Of the 658 generating units in the EFORd analysis, during calendar year 2005, 284 units had decreased EFORds, 254 units had increased EFORds and the remaining 120 units had unchanged EFORds. The 284 units with lower forced outage rates reduced the EFORd by 3.5 percentage points from 10.8 percent to the observed 7.3 percent EFORd.

The increase in EFORd since 2001 for the PJM Mid-Atlantic Region and AP Control Zones together has been, in part, the result of a change in the mix of capacity resulting from the addition of combined-cycle and combustion turbine capacity. In 2001, this area had approximately 67,400 MW of installed capacity. Between 2001 and 2005, there was a net decrease in steam capability of approximately 400 MW, from 36,800 MW to 36,400 MW; no change in nuclear capability; and a net increase in combined-cycle and combustion turbine capability of 11,500 MW, from 14,000 MW in 2001 to 25,500 MW in 2005. In 2001 steam and nuclear capacity accounted for 74 percent of capacity; combined-cycle units and combustion turbines accounted for 21 percent. In 2005, steam and nuclear capacity accounted for 63 percent of capacity; combined-cycle units and combustion turbines accounted for 32 percent.

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

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

Of the 2.7 percentage point change in system EFORd from 2001 to 2005 (See Table 5-23), 2.2 percentage points, or 81 percent, were contributed by combined-cycle and combustion turbine units. Changes in outage rates by unit type and changes in capacity by unit type combine to produce the observed impacts on the system EFORd. Both increased combustion turbine and combined-cycle capacity and increased forced outage rates for these unit types have contributed to the increased system EFORd. Table 5-24 shows the relative contributions of increased EFORd and increased capacity to EFORd levels by unit type and for the system. Twenty-six percent of the contribution of combined-cycle units to the increased system EFORd was the result of additional combined-cycle capacity while more than 94 percent of the contribution of combustion turbine units to the increased system EFORd was the result of higher EFORd levels for combustion turbines. Overall, 92 percent of the increase in EFORd from 2001 to 2005 was the result of increased EFORd rather than by a change in the mix of units.

Table 5-24 - Percent change in contribution to EFORd (By unit type): 2001 compared to 2005

Unit Type	Percent Change in Contribution 2005 from 2001 Due to Change in Capacity	Percent Change in Contribution 2005 from 2001 Due to Change in EFORd
Combined Cycle	25.9 %	74.1 %
Combustion Turbine	5.7 %	94.3 %
Diesel	3.7 %	96.3 %
Hydroelectric	(2.7 %)	102.7 %
Nuclear	0.0 %	100.0 %
Steam	(3.6 %)	103.6 %
All Unit Types	8.1 %	91.9 %

Compared with the PJM Mid-Atlantic Region and AP Control Zones' average EFORd, combined-cycle average EFORd for 2001 was extremely low. For the combined-cycle units, EFORd increased to slightly greater than 5.3 percent in 2005 from slightly greater than 1.7 percent in 2001. Combined-cycle unit EFORd increased by 282 percent between 2001 and 2004 but decreased slightly in 2005. (See Table 5-25.)

Table 5-25 - Five-year PJM EFORd data comparison to NERC five-year average for different unit types

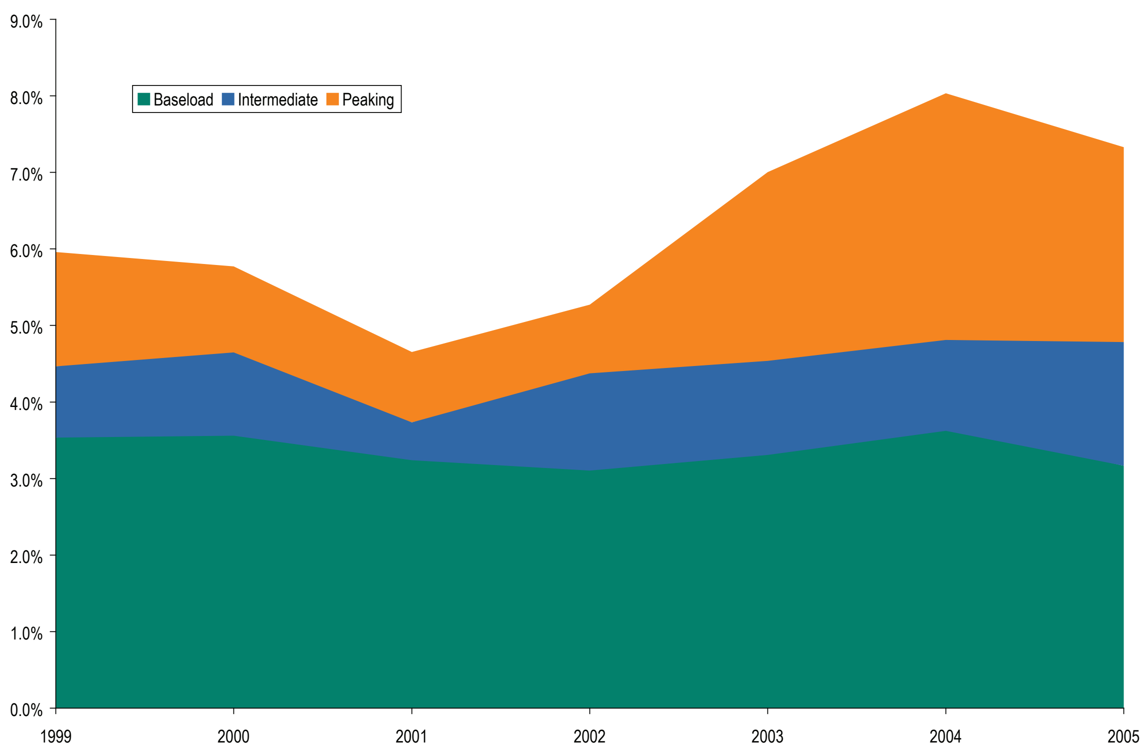
Unit Type	2001	2002	2003	2004	2005	NERC 2000-2004
Combined Cycle	1.7 %	5.3 %	5.7 %	6.5 %	5.3 %	NA
Combustion Turbine	4.6 %	4.4 %	8.9 %	9.3 %	14.0 %	8.9/10.1 %
Diesel	10.6 %	7.1 %	5.7 %	10.4 %	14.0 %	14.1 %
Run of River Hydro	1.2 %	1.0 %	0.9 %	2.5 %	1.9 %	3.6 %
Nuclear	1.5 %	1.7 %	2.1 %	3.4 %	1.4 %	4.3 %
Pumped Storage	0.8 %	1.1 %	1.3 %	2.1 %	1.2 %	4.6 %
Steam	6.4 %	7.1 %	9.0 %	10.3 %	8.6 %	6.2 %
Overall	4.6 %	5.2 %	7.0 %	8.0 %	7.3 %	NA

Table 5-25 compares PJM EFORd data by unit type to North American Electric Reliability Council (NERC) data for corresponding unit types.[51] NERC did not publish average EFORd for combined-cycle units because the new calculations for combined-cycle blocks were not ready and had not been tested.[52] While the PJM combustion turbine forced outage rates have been near or below the NERC five-year average, the PJM EFORd for combustion turbines exceeded the NERC average in 2005.[53] PJM 2005 forced outage rates for hydroelectric and nuclear units were below the NERC averages while PJM forced outage rates for steam exceeded the NERC averages.

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.[54] Figure 5-12 shows the increased contribution of intermediate and peaking units to system average EFORd beginning in 2001. Of 11,500 MW of combined-cycle and combustion turbine units added since 2001, approximately 10,800 MW are in the intermediate (9,400 MW) and peaking (1,400 MW) classes.

Figure 5-12 - Contribution to EFORd by duty cycle



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

52 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.

53 NERC defines combustion turbines in two categories: jet engines and gas turbines. Their EFORd for the 2000 to 2004 period are 8.9 percent and 10.1 percent, respectively, per the NERC GADS "2000-2004 Generating Unit Statistical Brochure - Units Reporting Events." < ftp://www.nerc.com/pub/sys/all_updl/gads/gar/2000-2004-Generating-Unit-Statistical-Brochure-Units-Reporting-Events.zip > (28 KB).

54 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.

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 – spinning reserve services; and 6) operating reserve – supplemental reserve services.[1] Of these, PJM currently provides regulation, energy imbalance and spinning reserve services through market-based mechanisms. 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.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes). Longer term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Spinning reserve is a form of primary reserve. To provide spinning a generator must be synchronized to the system and capable of providing output within 10 minutes.

Both the Regulation and Spinning Reserve Markets are cleared on a real-time basis. A unit can be selected for either spinning reserve or regulation or neither, but it cannot be selected for both. The Regulation and Spinning Reserve Markets are cleared simultaneously and cooptimized with the Energy Market and operating reserve requirements to minimize the cost of the combined products.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling.[3] 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.

During the last two calendar years, PJM has 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. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[4]

- **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,[5] and the Allegheny Power Company (AP) Control Zone.[6]

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE.

3 See "PJM Manual for Scheduling Operations, M-11," Revision 25 (August 19, 2005), p. 71.

4 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

5 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

6 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 the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

- **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).[7]

- **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, ComEd, AEP and DAY Control Zones 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.

In both Phase 4 and Phase 5, PJM operated two Regulation Markets: one for the Mid-Atlantic Region and a second for the Western Region. On August 1 of Phase 5, PJM combined both into a single PJM Combined Regulation Market for a six-month trial period. After the trial period, based on analysis of market results and a report by the PJM Market Monitoring Unit (MMU), PJM stakeholders will vote on whether to keep the combined market.

During Phase 4, PJM operated three Spinning Reserve Markets: one for the Mid-Atlantic Region, one for the Western Region and one for the ComEd Control Zone. During Phase 5, PJM operated a fourth Spinning Reserve Market for Dominion.

The analysis treats each of the two Regulation Markets and each of the three Spinning Reserve Markets separately during Phase 4. The market analysis treats each of the two Regulation Markets separately during the May 1 through July 31 component of Phase 5 (Phase 5-a), and as a single Regulation Market during the August 1 through December 31 component of Phase 5 (Phase 5-b). Each of the four Spinning Reserve Markets is treated separately for the entire Phase 5 period.

Overview – Regulation and Spinning Reserve Markets

The MMU has reviewed structure, conduct and performance indicators for the identified Regulation Markets. The MMU concludes that the Regulation Markets functioned effectively, except for some minor problems of insufficient regulation supply shortly after the start of Phase 5 and during times of minimum generation. The Regulation Markets produced competitive results throughout calendar year 2005 based on the regulation market-clearing price. The Regulation Market prices reflected the fact that offers in the Western Region were capped during Phase 4 and that the offers of two large participants, AEP and Dominion, were capped at cost plus a margin throughout Phase 5, in both cases because the Western Region Regulation Market was determined to be not structurally competitive.

7 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).

The MMU has reviewed structure, conduct and performance indicators for the identified Spinning Reserve Markets. The MMU concludes that the Spinning Reserve Markets functioned effectively. The Spinning Reserve Markets produced competitive results throughout calendar year 2005 based on the spinning market-clearing price. The Spinning Reserve Market prices reflected the fact that all offers were capped at cost plus a margin because the markets have been determined to be not structurally competitive.

The Regulation Markets

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 structure of the Combined Regulation Market was also evaluated based on the five months of available data and the MMU concluded that this market is characterized by lower levels of concentration, smaller market shares, a smaller number of hours with pivotal suppliers and inelastic demand. The conduct of market participants within these market structures has been consistent with competition consistent with existing offer capping, and the market performance results have been competitive.

- **Mid-Atlantic Region.** The Regulation Market in the PJM Mid-Atlantic Region was cleared based on participants' price offers during Phases 4 and 5-a. All suppliers were paid the market-clearing price, which is a function of the supply curve and PJM-defined demand. The supply curve consists of offered and eligible MW and the associated offer prices which are a combination of unit-specific offers plus opportunity cost (OC) as calculated by PJM.[8]

- **Western Region.** The Regulation Market in the Western Region during Phase 4 was cleared based on participants' cost-based offers. The cost-based regulation offers are defined to be the unit-specific incremental cost of providing regulation plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM. During Phase 5-a, the market was cleared using a combination of price-based offers and cost-based offers. In Phase 5, Dominion and AEP were required to make cost-based offers based on their dominant position in the market while other participants made price offers.

- **PJM Combined Regulation Market.** During the trial period for the PJM Combined Regulation Market, the market was cleared using a combination of price-based offers and cost-based offers. Dominion and AEP were required to make cost-based offers based on their dominant position in the market while other participants made price offers.

Market Structure

- **Demand.** Demand for regulation is determined by PJM based on an evaluation of the regulation required in order to meet reliability objectives. Required regulation remained constant for each control region throughout 2005 except for two periods during which a temporary adder was implemented at the direction of PJM.

8 As used here, the term, "opportunity cost" (OC), refers to the estimated lost opportunity cost (LOC) that PJM uses to create a supply curve on an hour-ahead basis. The term, "lost opportunity cost," refers to opportunity costs included in payments to generation owners.

- **Supply.** The supply of offered and eligible regulation in the PJM Mid-Atlantic Region was generally both stable and adequate, with an average 1.92 ratio of regulation supply offered and eligible to the hourly regulation requirement during Phases 4 and 5-a. While the average ratio of hourly regulation supply offered and eligible to regulation required was 1.64 for the Western Region during Phases 4 and 5-a, at times an inadequate supply of regulation was offered and eligible to participate in the market on an hourly basis in the Western Region. The average ratio of hourly regulation supply offered and eligible to regulation required was 1.88 for the PJM Combined Regulation Market during Phase 5-b.

Concentration of Ownership

- **Mid-Atlantic Region.** During Phase 4 and Phase 5-a, the PJM Mid-Atlantic Region Regulation Market for eligible regulation had an average Herfindahl-Hirschman Index (HHI)[9] of 1751 which is classified as "moderately concentrated."[10] Less than 1 percent of the hours had an eligible regulation HHI above 2500. There were two suppliers with market shares greater than, or equal to, 20 percent. Seven percent of the hours had a single pivotal supplier, 48 percent of the hours had two pivotal suppliers and 88 percent of the hours had three pivotal suppliers.

- **Western Region.** During Phase 4 and Phase 5-a, the Western Region Regulation Market for eligible regulation had an average HHI of 2802 which is classified as "highly concentrated" and 58 percent of the hours had an HHI above 2500. There was a single pivotal supplier in 62 percent of the hours. One hundred percent of the hours had two pivotal suppliers.

- **PJM Combined Regulation Market.** During Phase 5-b, the PJM Combined Regulation Market had an average HHI of 1079 which is classified as "moderately concentrated." No suppliers had market shares greater than, or equal to, 20 percent. During 1 percent of hours, there was a single pivotal supplier. During 6 percent of hours, there were two pivotal suppliers. During 29 percent of the hours, there were three pivotal suppliers. For all units except CTs, during 5 percent of hours, there was a single pivotal supplier, during 23 percent of hours, there were two pivotal suppliers and during 68 percent of the hours, there were three pivotal suppliers.

Market Conduct

- **Offers.** The offer price is the only component of the total regulation offer price provided by the unit owner and is applicable for the entire operating day. The regulation offer price is subject to a $100 per MWh offer cap in the Mid-Atlantic Region, was subject to offer capping in Phase 4 in the Western Region and was subject only to a $100 per MWh offer cap in Phase 5 in the Western Region, with the exception of the dominant suppliers, Dominion and AEP, whose offers were capped at marginal cost plus $7.50 per MWh plus opportunity cost. The average MW-weighted offer price for regulation in the PJM Mid-Atlantic Region during Phases 4 and 5-a was $15.63. The average MW-weighted offer price for regulation in the Western Region Regulation Market during Phases 4 and 5-a was $7.73. For the PJM Combined Regulation Market during Phase 5-b, the average MW-weighted offer price for regulation was $16.29.

9 See Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
10 The market structure metrics reported in this summary are based on regulation capacity that is both offered to the market and is eligible to provide regulation.

Market Performance

- **Price.** For the entire PJM regional transmission organization (RTO) from January 1, 2005, to December 31, 2005, the average price per MWh (regulation market-clearing price) associated with meeting PJM's demand for regulation was $49.73. For the PJM region during Phases 4 and 5-a, the average price per MWh for regulation was $36.39. For the Western Region Regulation Market during Phases 4 and 5-a, the average price per MWh for regulation was $42.64. For the PJM Combined Regulation Market during Phase 5-b, the average price per MWh was $64.03.

The Spinning Reserve Markets

The structure of each of the Spinning Reserve Markets 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 and opportunity cost. The conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Prices for spinning in the PJM Mid-Atlantic Region, the ComEd Control Zone, the Western Region and Dominion are market-clearing prices determined by the supply curve and PJM-defined demand. The cost-based spinning offers are defined to be the unit-specific incremental cost of providing spinning reserve plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM.

Market Structure

- **Demand.** Computed in accordance with the specific spinning reserve requirements, the average MW spinning requirement was: 1,091 MW for the PJM Mid-Atlantic Region; 217 MW for the ComEd Spinning Zone; 437 MW for the Western Region; and 5 MW for the Southern Spinning Reserve Zone (May to December only).

- **Supply.** For the PJM Mid-Atlantic Region, the offered and eligible excess supply ratio was 1.15. For the Western and Southern Regions, the ratio was 1.76. For the ComEd Control Zone, the ratio was 1.21.

- **Concentration of Ownership.** In 2005, market concentration was high in the Tier 2 Spinning Reserve Market. The average offered and eligible Spinning Reserve Market HHI for the PJM Mid-Atlantic Region throughout 2005 was 2940. The average Spinning Reserve Market HHI for the Western Region was 4593. The average Spinning Reserve Market HHI for ComEd Control Zone was 8844. The average Spinning Reserve Market HHI for Dominion was 10000.

Market Performance

- **Price.** Load-weighted, average price associated with meeting the PJM system demand for Tier 2 spinning reserve throughout 2005 was $14.41 per MW, a $0.45 per MW decrease from 2004. The load-weighted, average price in the PJM Mid-Atlantic Region for Phases 4 and 5 was $15.44 per MW. The load-weighted, average price for spinning reserve in the ComEd Control Zone during Phases 4 and 5 was $12.73. The load-weighted, average price for spinning in the Western Control Zone during Phases 4 and 5 was $13.23. The load-weighted, average price for spinning in Dominion during Phase 5 was $13.08.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition. The MMU will make a recommendation in the near future as to whether the consolidation has resulted in a market that is structurally competitive. The market continues to be based on price offers for most sellers and all sellers are paid a market-clearing price based on offers plus opportunity costs. The result of this design has been a competitive outcome and consistent with competitive offers from all participants whether offer-capped or not. The marginal costs of providing regulation have been clearly defined and are consistent with the offers that would be made if the suppliers were behaving competitively.

PJM's Spinning 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 this approach to ancillary service markets. Even in the presence of structurally non-competitive markets, there are transparent, market-clearing prices based on competitive offers that account explicitly and accurately for opportunity costs. 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.

Regulation Markets

Regulation Market Structure

Two major changes affected the structure of the Regulation Market in 2005. The first was the integration of Dominion into the Western Region Regulation Market on May 1, 2005. The second was the implementation of the PJM Combined Regulation Market on August 1, 2005.

Demand

Demand for regulation does not change with price (is price inelastic). The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand will be referred to in this report as required regulation.

The PJM Mid-Atlantic Region has different regulation requirements for on-peak hours and off-peak hours. The regulation requirement for the peak period is 1.1 percent of the peak-load forecast; for the off-peak period, it is 1.1 percent of the valley-load forecast.[11] During Phases 4 and 5-a, PJM Mid-Atlantic Region regulation requirements ranged from 226 MW of regulation capability for off-peak periods to 649 MW for on-peak periods. The average required regulation was 434 MW.

In the Western Region, the regulation requirement was 1.0 percent of the peak forecast load and did not vary between on-peak and off-peak periods. During Phases 4 and 5-a, the requirement ranged from 320 MW to 771 MW, averaging 517 MW.

During Phase 5-b, the PJM Mid-Atlantic Region and the Western Region Regulation Markets were combined into the PJM Combined Regulation Market. The regulation requirement for this combined market was defined to equal the sum of the separate regulation requirements for each region. During Phase 5-b, the regulation requirement ranged from 662 MW to 1,404 MW, averaging 978 MW.

Although the required regulation specification remained constant for each control region throughout 2005, a temporary adder was implemented at the direction of PJM for two periods. As a result, regulation was purchased in addition to the full regulation requirement. On October 23, 2004, in response to problems after the integration of the ComEd Control Zone into the Western Region, required regulation was increased by 75 MW for each regulation zone. This regulation adder was subsequently reduced until regulation was returned to its base requirement on February 11, 2005.

11 See “PJM Manual for Scheduling Operations, M-11,” Revision 25 (August 19, 2005), p. 51.

On April 15, 2005, in response to a persistent problem with frequency excursions, a 100 MW increment was added to the regulation demand for both the Mid-Atlantic and Western Regions. It was phased out and then eliminated on May 14, 2005. Table 6-1 contains a list of regulation adder amounts by date.

Table 6-1 - Temporary regulation adder: October 23, 2004, to May 15, 2005

Regulation Adder Date	Change in Regulation MW per Control Zone	Total Regulation Adder (MW) per Control Zone
23-Oct-04	75	75
29-Oct-04	(75)	0
01-Nov-04	75	75
11-Nov-04	100	175
17-Dec-04	(50)	125
07-Jan-05	(25)	100
14-Jan-05	(25)	75
26-Jan-05	(25)	50
04-Feb-05	(25)	25
11-Feb-05	(25)	0
15-Apr-05	100	100
06-May-05	(25)	75
08-May-05	(75)	0
12-May-05	50	50
14-May-05	(50)	0

The temporary additional regulation requirements between mid-April and mid-May reflected an effort by PJM to solve simultaneous problems of insufficient regulation in the Western Region Regulation Market, particularly during off-peak hours, and frequency excursions that impacted PJM's compliance requirement for CPS2.[12]

Regulation obligation is determined hourly for each load-serving entity (LSE) by applying the real-time load ratio share (adjusted for scheduled load responsibility) to the actual amount of regulation assigned for that hour adjusted for any bilaterals and self-supply. The hourly regulation charge for each LSE is equal to the hourly regulation market-clearing price (RMCP) multiplied by the MW of regulation purchased from the market, plus the LSE's percentage share of any opportunity cost incurred by generation owners over and above the RMCP, plus the LSE's percentage share of any unrecovered costs incurred by those units called on by PJM for the sole purpose of providing regulation.

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. Assigned regulation is selected from regulation that is both offered and eligible.

12 See Appendix F, "Ancillary Service Markets," for additional information on area control error (ACE) control and control performance standard (CPS).

Regulation capability represents the total volume of regulation capability reported by resource owners based on unit characteristics.

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 may be submitted on a daily basis and these daily offers may be modified on an hourly basis.

Regulation offered and eligible represents the level of regulation capability actually 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 will be included in regulation offered based on the daily offer and availability status, but that regulation capability will not be 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 will be included in regulation offered if the owner of a unit offers regulation, but that regulation capability will not be 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 will be included in regulation offered but that regulation capability will not be eligible if the unit is not operating, unless the unit is a combustion turbine that meets specific operating parameter requirements.

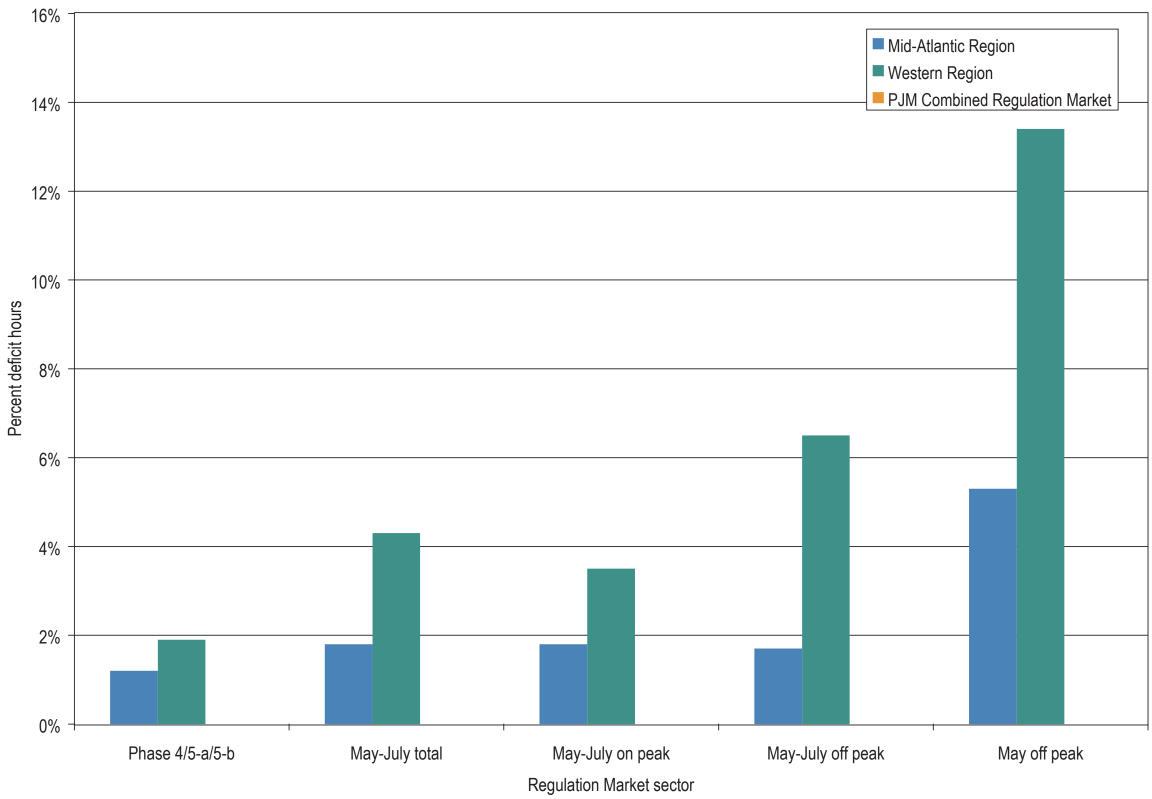
Only those offers which are eligible to provide regulation in an hour are part of supply for that hour, and only those offers are considered for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the regulation market-clearing mechanism to provide regulation service for a given hour.

While the average regulation supply-to-requirement ratio of offered regulation in the Western Region Regulation Market during Phase 5-a was generally adequate at 1.70, the situation was more complicated than the supply-to-requirement ratio indicates. Regulation capacity was always adequate in the sense that the total reported capability was adequate.[13] Occasionally, however, PJM dispatchers had to redispatch generation uneconomically to satisfy reliability requirements. PJM encountered some difficulty with insufficient regulation supply in the Western Regulation Zone during Phase 5-a. Shortly after the Dominion integration on May 1, 2005, there was at times an inadequate supply of regulation that was offered and eligible to participate in the market on an hourly basis. This situation was most acute in the Western Region Regulation Market in May 2005 during off-peak periods when market solutions resulted in deficits 13.6 percent of the time and occasional off-peak hourly price spikes. (See Figure 6-1.) These higher than normal deficits generally occurred during off-peak hours when regulation-capable units were unavailable to regulate because they were not operating. In May, PJM frequently operated under minimum generation conditions, especially during off-peak hours. The combination of a regulation deficit and minimum generation conditions required dispatchers to balance the need for more regulation with the need for less generation. Dispatchers at times chose to operate with regulation deficits. This situation improved during June (deficits in 5.3 percent of all periods) and was resolved in July when the deficit percentage returned to its overall Phases 4 and 5-a average.

13 See "Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned," in Appendix F, "Ancillary Service Markets," for a definition of capacity, availability and supply.

Figure 6-1 compares the percentage of regulation deficit hours across several Regulation Market periods, including all of 2005, Phase 5 only, off-peak and on-peak hours and off-peak hours in May. The abnormally high deficits that occurred in the Western Region particularly during off-peak hours in early May are clearly indicated.

Figure 6-1 - Regulation deficit analysis: Calendar year 2005



Regulation deficits in the west were reduced during June and returned to normal in July. Also indicated in Figure 6-1 is the extent to which regulation deficits were all but eliminated after the PJM Combined Regulation Market. There was only one period of regulation deficit in the PJM Combined Regulation Market during Phase 5-b. This deficit does not show up in Figure 6-1 because the percentage of regulation deficit hours rounds to zero percent.

Concentration of Ownership

Market Structure Definitions

The market structure analysis follows the Commission logic specified in the AEP order.[14] The logic of the delivered price test is followed by calculating market share, HHI and pivotal supplier metrics for each market configuration.[15] The analysis presented here differs in two ways from the Commission's delivered price test. The delivered price test would start with the universe of regulation offered and eligible and then limit the analysis to those offered and eligible units that could provide regulation at less than or equal to 1.05 times the clearing price. The analysis here uses a proxy for the 1.05 times the clearing price definition used to define the relevant market. In PJM, the supply of regulation generally consists of two relatively distinct segments: an all units except combustion turbine (CT) segment (consisting of steam and hydroelectric units) and a CT segment. While steam, hydroelectric and CT units can and do provide regulation, the steam/hydroelectric segment is generally lower cost and is relatively homogeneous while the CT segment is generally significantly higher cost and similarly relatively internally homogeneous. Rather than directly applying the 1.05 times the clearing price market definition, the analysis here focuses separately on the steam/hydroelectric and the CT portions of the market. The steam/hydroelectric segment of the market is used in place of including only sellers that offer for a price less than or equal to the clearing price times 1.05 when a steam/hydroelectric unit is marginal, although the segment approach results in a substantially larger market definition. The CT segment is similarly used in place of including only sellers that offer for a price less than or equal to the clearing price times 1.05 when a CT unit is marginal, although again the segment approach probably results in a larger market definition. The data are presented including all units, all units except CTs (steam and hydroelectric) and CTs. In addition, the analysis here includes the results of the one, two and three pivotal supplier tests.

The analysis here includes all regulation provided by each supplier and made offered and eligible. While the market structure results are reported for regulation offered, this is not directly relevant to a determination of whether a market structure is competitive. 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, or gross supply by participant 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 Commission'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. The analysis presented here goes further in order to analyze the significance of excess supply. The MMU applies the pivotal supplier test using one, two and three pivotal suppliers. In addition, when there are hours with one, two 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.

14 107 FERC ¶ 61,018 (2003) ("AEP Order"), 108 FERC ¶ 61,026 (2004)("Order on Rehearing").
15 AEP Order at 105 *et seq.*

The pivotal supplier tests represent an analytical approach to the issue of excess supply. Excess supply, by itself, is not necessarily 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 Mid-Atlantic Regulation Market – Phases 4 through 5-a

During Phases 4 through 5-a, in the Regulation Market in the Mid-Atlantic Region, the offer capability was 2,408 MW.[16] The level of regulation resources offered on an hourly 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 2005 the average hourly offer level was 1,128 MW or 47 percent of offer capability while the average hourly eligible offer level was 835 MW or 35 percent of offer capability.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 2.60 for the PJM Mid-Atlantic Region during Phases 4 and 5-a. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period. Based upon regulation offered and eligible, this ratio averaged 1.92. The average regulation requirement for the PJM Mid-Atlantic Region during 2005 was 434 MW.

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible, and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 2064 to a minimum of 1088 with an average value of 1510. Based upon regulation offered and eligible, HHI values ranged from a maximum of 2787 to a minimum HHI of 1190, with an average value of 1751. Less than 1 percent of hours had an eligible regulation HHI above 2500. Based upon regulation assigned, HHI values ranged from a maximum of 9690 to a minimum HHI of 1118. The average HHI value for regulation assigned was 2260. Thirty-one percent of hours had an assigned regulation HHI above 2500. Table 6-2 summarizes the January 2005 through July 2005 PJM Mid-Atlantic Region Regulation Market HHIs.

Table 6-2 - PJM Mid-Atlantic Region Regulation Market hourly HHI: Phases 4 and 5-a

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	1088	1510	2064	0%
Eligible	1190	1751	2787	0%
Assigned	1118	2260	9690	31%

As noted above, regulation supply in PJM is bifurcated into the combustion turbine (CT) segment and the all units except CTs segment because, while some CTs provide regulation, they are very expensive to operate solely to provide regulation. In order to approximate the delivered price test approach, the Regulation Market HHI is reported with and without CTs. (See Table 6-3.) In the PJM Mid-Atlantic Region, HHIs are slightly lower without CTs because the CTs are disproportionately owned by the company with the largest market share.

16 Offer capability is defined as the maximum daily offer volume for each offering unit during the period without regard to the actual availability of the resource.

Table 6-3 - PJM Mid-Atlantic Region Regulation Market hourly HHI (All units except CTs): Phases 4 and 5-a

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	1078	1475	2354	0%
Eligible	1183	1718	2941	0%
Assigned	1118	2266	9690	31%

During Phases 4 and 5-a, two suppliers had market shares greater than, or equal to, 20 percent based on regulation offered and eligible. For the market segment excluding CTs, two suppliers had market shares greater than, or equal to, 20 percent based on regulation offered and eligible.

During Phases 4 and 5-a, 7 percent of the hours failed the single pivotal supplier test for offered and eligible supply in the PJM Mid-Atlantic Region's market.[17] This means that, during the seven-month period, for 7 percent of the hours the total regulation requirement could not be met in the absence of the largest supplier. Forty-eight percent of the hours failed the two pivotal supplier test. This means that, during 48 percent of the hours, the total regulation requirement could not be met in the absence of the two largest suppliers. Eighty-eight percent of the hours failed the three pivotal supplier test. This means that, during 88 percent of the hours, the total regulation the regulation requirement could not be met in the absence of the three largest suppliers.

For the market segment excluding CTs, the percentage of one pivotal supplier hours in the eligible Regulation Market increases from 7 percent to 10 percent, the percentage of two pivotal supplier hours increases from 48 percent to 52 percent and the percentage of three pivotal supplier hours increases from 88 percent to 89 percent. Table 6-4 summarizes the PJM Mid-Atlantic Region Regulation Market pivotal supplier statistics for Phases 4 and 5-a. The pivotal supplier statistics are also presented for all regulating units except CTs. (See Table 6-5.) Three companies are pivotal more than 75 percent of the three pivotal supplier intervals for all units, and for the all units except CTs segment.

Table 6-4 - PJM Mid-Atlantic Region Regulation Market pivotal supplier statistics: Phases 4 and 5-a

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	0%	7%
2 pivotal	3%	48%
3 pivotal	35%	88%

Table 6-5 - PJM Mid-Atlantic Region Regulation Market pivotal supplier statistics (All units except CTs): Phases 4 and 5-a

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	0%	10%
2 pivotal	9%	52%
3 pivotal	52%	89%

17 The pivotal supplier results are provided for all offered regulation as additional information although these results are not directly relevant to the market structure analysis.

Based on these market structure results, the MMU concludes that the market structure of the PJM Mid-Atlantic Region Regulation Market during Phases 4 and 5-a can no longer be considered to be consistent with a competitive outcome. The combination of two market participants with market shares greater than, or equal to, 20 percent and the pivotal supplier results are not consistent with a competitive structure. The market in the PJM Mid-Atlantic Region was operated by PJM as a competitive market prior to the Combined Regulation Market.

Western Region Regulation Market – Phases 4 and 5-a

During Phases 4 and 5-a, in the Western Region Regulation Market, the submitted offer capability was 2,267 MW. The level of resources offered on an hourly level and the level of regulation resources both offered and eligible to participate on an hourly level in the Regulation Market were lower than the submitted regulation offer capability. Between the beginning of Phase 4 and the end of Phase 5-a, the average hourly offer level was 938 MW or 41 percent of the submitted capability, while the average hourly eligible offer level was 847 MW or 37 percent of the submitted capability.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 1.81 for the Phases 4 and 5-a Western Region Regulation Market. Based upon regulation offered and eligible, this ratio averaged 1.64. The average regulation requirement for the Phases 4 and 5-a Western Region Regulation Market was 517 MW.[18]

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 4357 to a minimum of 1748 with an average value of 2730. Fifty-eight percent of hours had an offered regulation HHI above 2500. Based upon regulation offered and eligible, HHI values ranged from a maximum of 4810 to a minimum HHI of 1757, with an average value of 2802. Fifty-eight percent of hours had an eligible regulation HHI above 2500. Based upon regulation assigned, HHI values ranged from a maximum of 7162 to a minimum HHI of 1698. The average HHI value for regulation assigned was 2973. Sixty-four percent of hours had an assigned regulation HHI above 2500. Table 6-6 summarizes the January through July 2005 Western Region Regulation Market HHIs.

Table 6-6 - PJM Western Region Regulation Market hourly HHI: Phases 4 and 5-a

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	1748	2730	4357	58%
Eligible	1757	2802	4810	58%
Assigned	1698	2973	7162	64%

18 See Appendix F, "Ancillary Service Markets," for additional detail on the regulation requirements.

For the market segment excluding CTs, HHIs in the Western Region Regulation Market are somewhat higher. (See Table 6-7.)

Table 6-7 - PJM Western Region Regulation Market hourly HHI (All units except CTs): Phases 4 and 5-a

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	1859	2960	4973	60%
Eligible	1856	3029	5249	62%
Assigned	1738	2984	7162	65%

During Phases 4 and 5-a, one supplier had a market share greater than, or equal to, 20 percent based on offered and eligible regulation. For the market segment excluding CTs, one supplier had a market share greater than, or equal to, 20 percent based on offered and eligible regulation.

During Phases 4 through 5-a, 62 percent of the hours failed the single pivotal supplier test for offered and eligible supply in the Western Region Regulation Market. This means that, during the seven-month period, the total regulation requirement could not be met for 62 percent of the hours in the absence of the largest supplier. One hundred percent of the hours failed the two pivotal supplier test. This means that, during 100 percent of the hours, the total regulation requirement could not be met in the absence of the two largest suppliers. One hundred percent of the hours failed the three pivotal supplier test. This means that, during 100 percent of the hours, the total regulation requirement could not be met in the absence of the three largest suppliers. Table 6-8 summarizes the Western Region Regulation Market pivotal supplier statistics for Phases 4 through 5-a.

Table 6-8 - PJM Western Region Regulation Market pivotal supplier statistics: Phases 4 and 5-a

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	30%	62%
2 pivotal	100%	100%
3 pivotal	100%	100%

Table 6-9 presents pivotal supplier statistics for the Western Region regulation pool for all units except CTs. Eighty-eight percent of hours fail the one pivotal supplier test. In both the all units and all units except CTs market segments the same company that was the one pivotal supplier was also pivotal for more than 95 percent of the hours in which two and three suppliers were pivotal.

Table 6-9 - PJM Western Region Regulation Market pivotal supplier statistics (All units except CTs:): Phases 4 and 5-a

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	69%	88%
2 pivotal	100%	100%
3 pivotal	100%	100%

Based on these market structure results, the MMU concludes that the market structure of the Western Region Regulation Market was not consistent with a competitive outcome. The Regulation Market in the Western Region was operated by PJM, with the two dominant suppliers offer-capped, as a market with market-clearing prices during Phases 4 and 5-a.

PJM Combined Regulation Market – Phase 5-b

The PJM Combined Regulation Market during Phase 5-b was comprised of the PJM Western Region (the ComEd, AEP, DAY, Dominion, DLCO and AP Control Zones) and the PJM Mid-Atlantic Region. For the Phase 5-b PJM Combined Regulation Market, the submitted capability was 5,491 MW. The average hourly offer level was 2,370 MW while the average hourly eligible offer level was 1,841 MW.

The ratio of the hourly regulation supply offered to the hourly regulation requirement averaged 2.42. Based upon regulation offered and eligible, this ratio averaged 1.88. The average regulation requirement for the Phase 5-b PJM Combined Regulation Market was 978 MW.

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 1331 to a minimum of 812 with an average value of 1001. Based upon regulation offered and eligible, HHI ranged from a maximum of 1562 to a minimum HHI of 866, with an average value of 1079. Based upon regulation assigned, HHI values ranged from a maximum of 2390 to a minimum of 878. The average HHI value for regulation assigned was 1299. Table 6-10 summarizes HHI results for the PJM Combined Regulation Market.

Table 6-10 - PJM Combined Regulation Market HHI: Phase 5-b

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	812	1001	1331	0 %
Eligible	866	1079	1562	0 %
Assigned	878	1299	2390	0 %

For the market segment excluding CTs, HHIs are essentially the same. (See Table 6-11.)

Table 6-11 - PJM Combined Regulation Market HHI (All units except CTs): Phase 5-b

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	845	1016	1417	0 %
Eligible	891	1080	1659	0 %
Assigned	878	1301	2400	0 %

During Phase 5-b, in the PJM Combined Regulation Market, no suppliers had a market share greater than, or equal to, 20 percent for regulation offered and eligible. For the market segment excluding CTs, no suppliers had a market share greater than, or equal to, 20 percent for regulation offered and eligible. For the CT market segment, two suppliers had market shares in excess of 20 percent for regulation offered and eligible.

During Phase 5-b, 1 percent of the hours failed the single pivotal supplier test for offered and eligible supply in the PJM Combined Regulation Market. This means that, during the five-month period, the total regulation requirement could not be met for 1 percent of the hours in the absence of the largest supplier. Six percent of the hours failed the two pivotal supplier test. This means that, during 6 percent of the hours, the total regulation requirement could not be met in the absence of the two largest suppliers. Twenty-nine percent of the hours failed the three pivotal supplier test. This means that, during 29 percent of the hours, the total regulation requirement could not be met in the absence of the three largest suppliers. Table 6-12 summarizes the PJM Combined Regulation Market's pivotal supplier results for Phase 5-b. For all units including CTs the same company that was the one pivotal supplier for more than one-third of the one pivotal supplier intervals was also pivotal for more than 75 percent of the two pivotal supplier intervals and more than 80 percent of the hours in which two and three suppliers were pivotal. A second company was pivotal during more than 25 percent of the two pivotal and approximately 50 percent of three pivotal hours.

Table 6-12 - PJM Combined Regulation Market pivotal supplier statistics: Phase 5-b

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	0%	1%
2 pivotal	0%	6%
3 pivotal	1%	29%

Table 6-13 presents pivotal supplier statistics for the PJM Combined Regulation Market's segment for all units except CTs.

Table 6-13 - PJM Combined Regulation Market pivotal supplier statistics (All units except CTs): Phase 5-b

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	0%	5%
2 pivotal	1%	23%
3 pivotal	14%	68%

For the market segment excluding CTs, the percentage of one pivotal supplier hours in the eligible Regulation Market increases from 1 percent to 5 percent, the percentage of two pivotal supplier hours increases from 6 percent to 23 percent and the percentage of three pivotal supplier hours increases from 29 percent to 68 percent. (See Table 6-13.) In the all units except CTs market segment, the same company that was the one pivotal supplier for more than two-thirds of the one pivotal supplier intervals was also pivotal for more than 80 percent of the two pivotal supplier intervals and more than 95 percent of the hours in which two and three suppliers were pivotal. A second company is pivotal during more than 60 percent of the two pivotal and three pivotal hours, while the third pivotal position is shared by three companies with an approximately equal frequency of occurrence.

The MMU will make a recommendation to PJM members in the near future regarding the structural competitiveness of this market.

Regulation Market Conduct

Regulation Offers

Generators wishing to participate in any of the PJM Regulation Markets must submit regulation offers for specific units by hour 1800 EPT of the day before the operating day. The regulation offer price is subject to a $100 per MWh offer cap in PJM control zones with the exception of the dominant suppliers Dominion and AEP whose offers are capped at marginal cost plus $7.50 per MWh plus opportunity cost. In the PJM Western Region during Phase 4, all regulation offers were capped at $7.50 per MWh plus the cost of providing regulation service because that market was determined to be not structurally competitive. 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 30 minutes before each operating hour.

PJM's Regulation Markets are cleared hourly, based upon both offers submitted by the units and the hourly opportunity cost of each unit.[19] The effective offer price is the sum of the unit-specific offer and the opportunity cost. In order to clear the market, PJM ranks units which offer and are eligible to regulate by effective offer price and selects the lowest offers in order until the amount of regulation required for the hour is satisfied at least cost. The price that results is the RMCP, and the unit that sets this price is the marginal unit.

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.

Regulation Market Performance

Regulation Prices

Figure 6-2 shows both the daily average regulation market-clearing price and the opportunity cost component for the marginal units in the PJM Mid-Atlantic Region during Phases 4 and 5-a. Figure 6-3 shows the same data for the Western Region Regulation Market during Phases 4 and 5-a. Figure 6-4 shows the same data for the PJM Combined Regulation Market during Phase 5-b. All units chosen to provide regulation during Phases 4 and 5 received as payment the higher of the clearing price multiplied by the unit's assigned regulating capability, or the unit's regulation bid multiplied by its assigned regulating capability plus the individual unit's real-time opportunity cost.[20]

Regulation credits are awarded to generation owners that have either self-scheduled regulation 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 bid times its assigned regulating capability plus the opportunity cost that unit incurred. Although most units are paid RMCP times their assigned regulation MW, the RMCP is itself strongly dependent on the lost opportunity cost based upon forecast LMP calculated for the marginal unit during market clearing. This means that the total cost of regulation is very strongly dependent upon lost opportunity cost, which is dependent upon forecast LMP. Figure 6-2, Figure 6-3 and Figure 6-4 graph the RMCP against the estimated lost opportunity cost of the marginal unit (calculated at market clearance, adjusted for real-time deviations in LMP and averaged over the day). Most of the cost of regulation comes from the lost opportunity cost of the marginal unit. The rest of the RMCP is the unit's regulation offer. The average offer of the marginal unit for the PJM Mid-Atlantic Region during Phases 4 and 5-a was \$15.33 per MW. The average offer of the marginal unit for the Western Region Regulation Market during Phases 4 and 5-a was \$8.66 per MW. The average offer of the marginal unit for the PJM Combined Regulation Market during Phase 5-b was \$13.16 per MW. In the PJM Mid-Atlantic Region Regulation Market during Phases 4 and 5-a, marginal unit lost opportunity cost (LOC) averaged 57 percent of the RMCP. In the Western Region Regulation Market during Phases 4 and 5-a, marginal unit LOC averaged 76 percent of RMCP. In the PJM Combined Regulation Market during Phase 5-b, marginal unit LOC averaged 79 percent of RMCP.

20 See "PJM Operating Agreement, Accounting, m28," 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.

Figure 6-2 - PJM Mid-Atlantic Region daily average regulation clearing price and adjusted estimated marginal unit opportunity cost: Phases 4 and 5-a

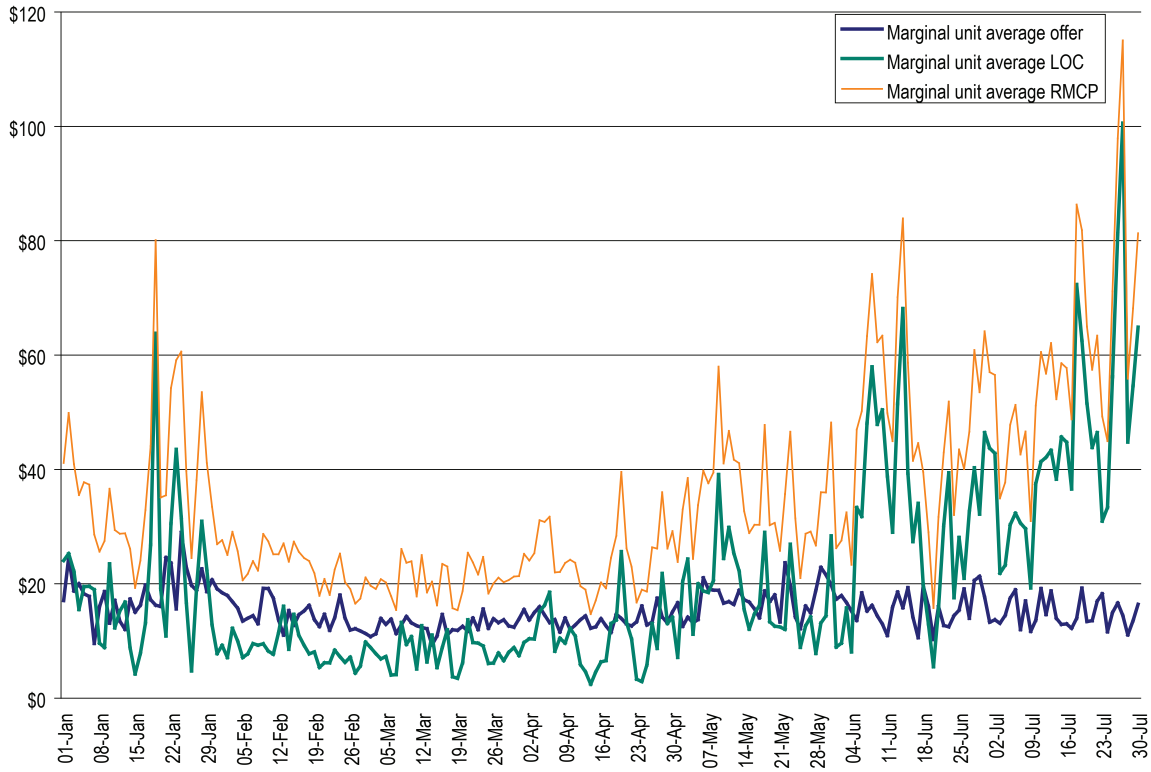


Figure 6-3 - PJM Western Region daily average regulation clearing price and adjusted estimated marginal unit opportunity cost: Phases 4 and 5-a

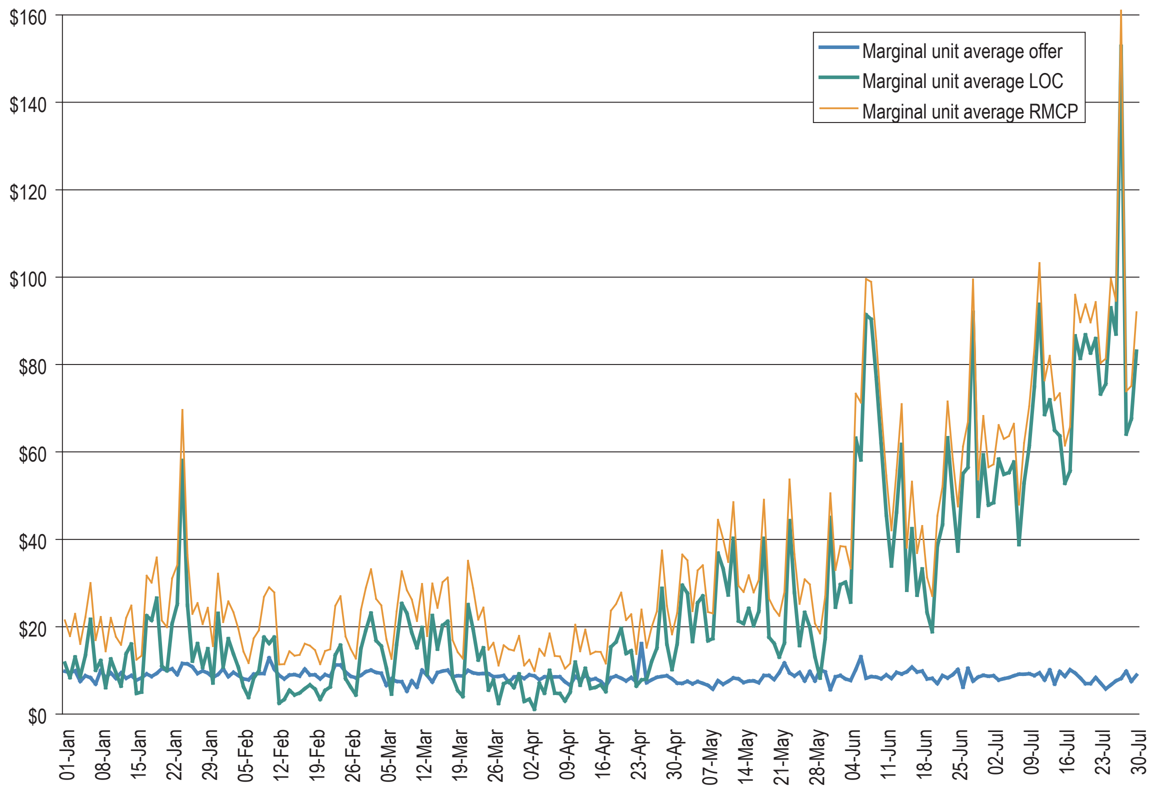


Figure 6-4 - PJM Combined Regulation Market daily average regulation clearing price and adjusted estimated marginal unit opportunity cost: Phase 5-b

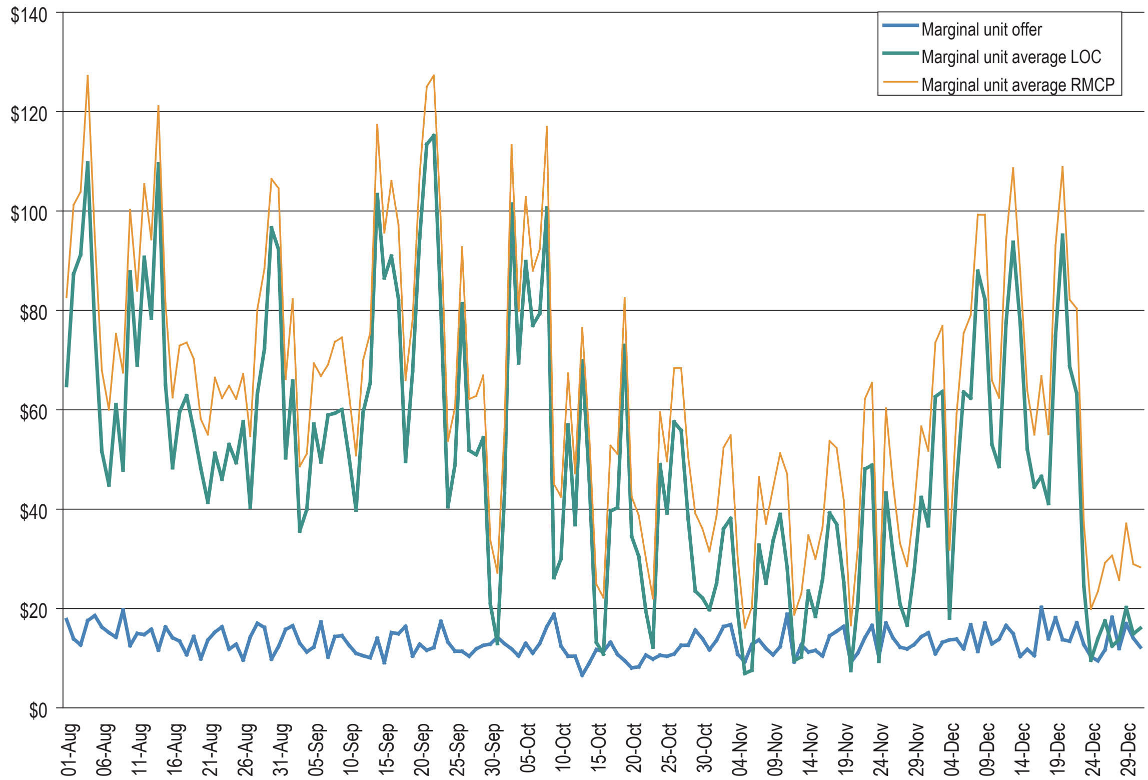


Figure 6-5, Figure 6-6 and Figure 6-7 compare the regulation price per MW to the regulation MW purchased for each of the Regulation Markets. As the regulation requirement is a linear function of daily forecast peak load in all markets, all three graphs show that despite considerable daily variation, the price of regulation and the demand for regulation increase or decrease together on a seasonal scale. System LMP increases with load because higher priced units must be dispatched to meet demand and those increases in system LMP cause the opportunity cost to rise by increasing the spread between LMP and the energy offers of the regulating units.

Figure 6-5 - PJM Mid-Atlantic Region daily regulation MW purchased vs. price per MW: Phases 4 and 5-a

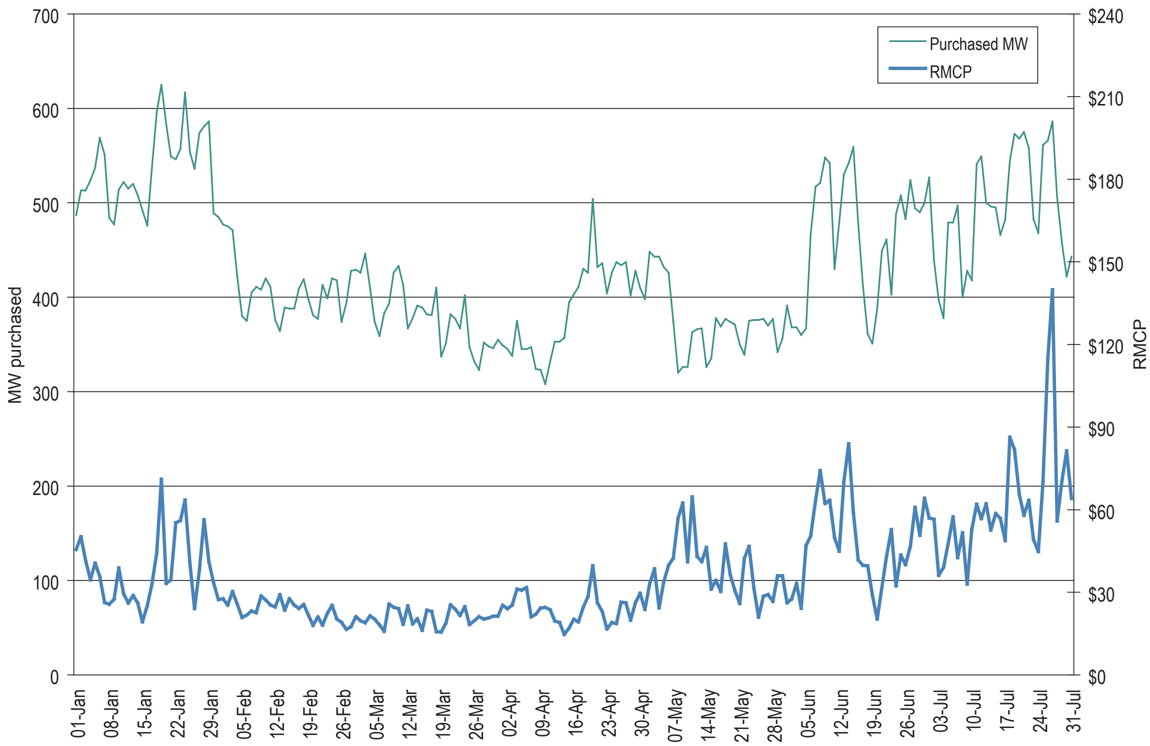


Figure 6-6 - PJM Western Region daily regulation MW purchased vs. price per MW: Phases 4 and 5-a

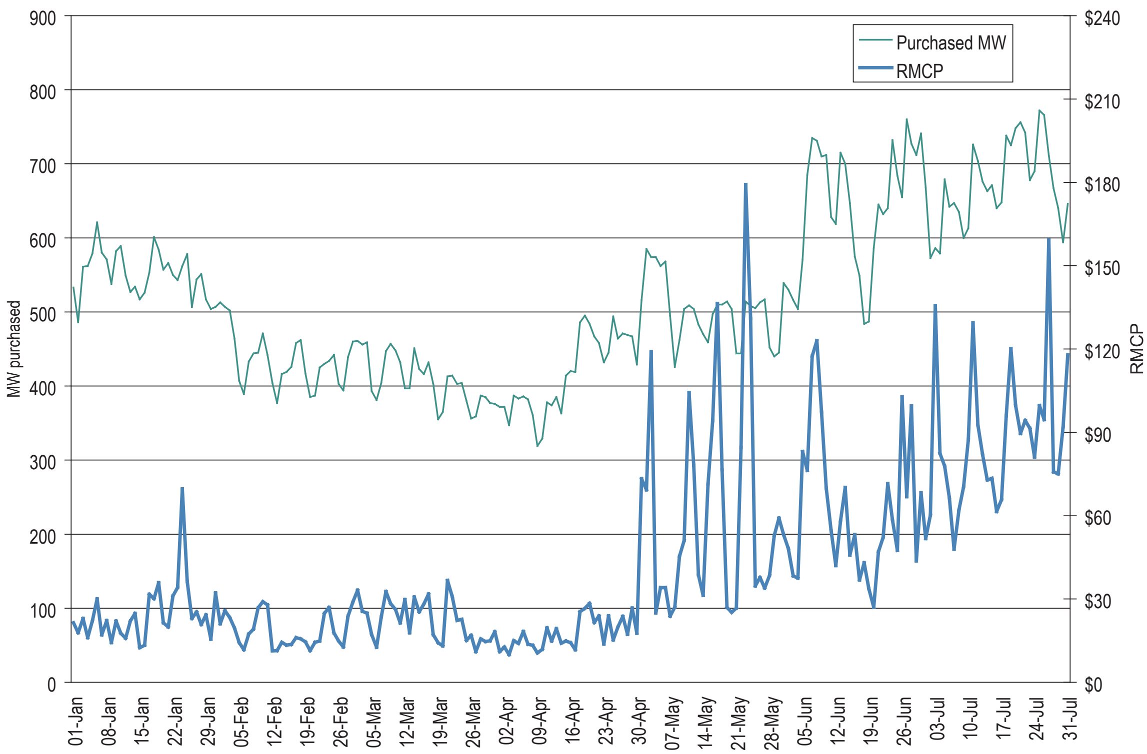
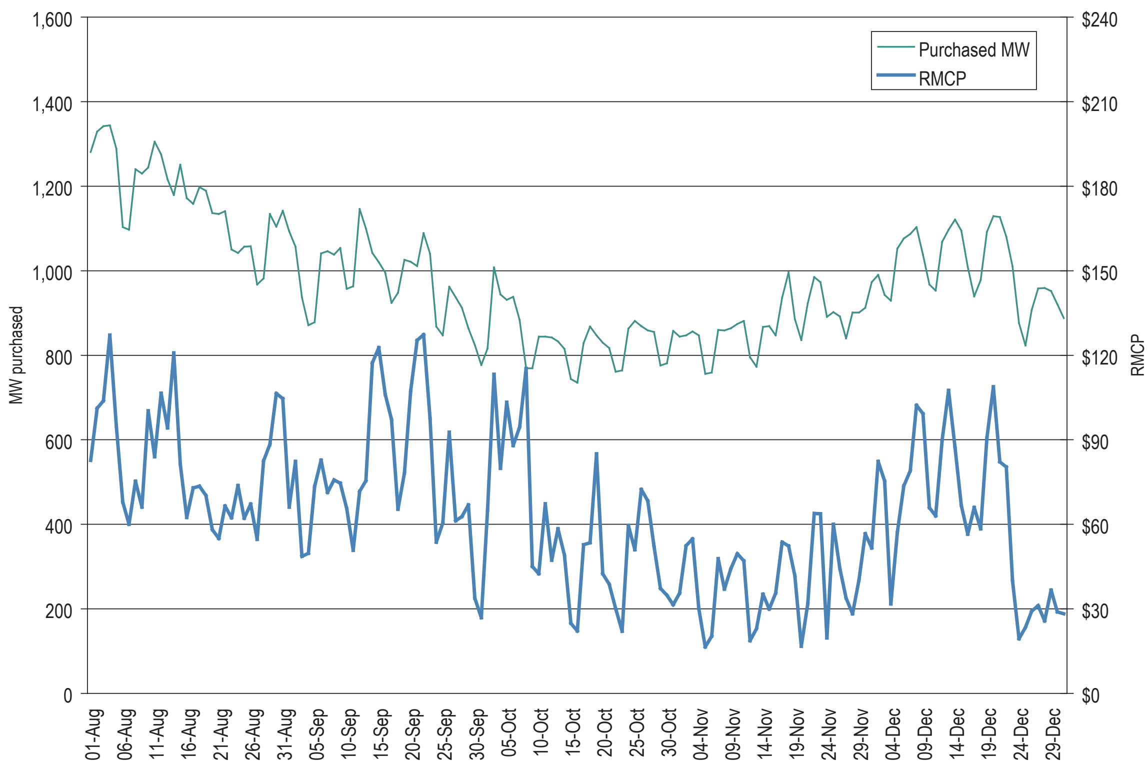


Figure 6-7 - PJM Combined Regulation Market daily regulation MW purchased vs. price per MW: Phase 5-b



Important exceptions to this general pattern occurred periodically in the Western Region after the integration of Dominion on May 1, 2005. (See Figure 6-6.) An hourly analysis of regulation MW purchased versus the regulation price reveals some extreme exceptions that resulted from deficits during off-peak hours and/or times of minimum generation events. A shortage of regulation-capable units (as existed in the Western Region in early May) combined with a minimum generation event required expensive combustion turbine units to be started to satisfy regulation requirements resulting in high clearing prices. Minimum generation events can cause shortages of regulation in the PJM Mid-Atlantic Region as well, but since the regulation requirement in the PJM Mid-Atlantic Region is lower during off-peak hours it is less likely. Overall, the inflexibility of demand and the shortage of available regulating units caused relatively wide price swings in the Western Region during Phase 5-a.

As Figure 6-5, Figure 6-6 and Figure 6-7 also show, regulation prices during calendar year 2005 were seasonally higher in January, remained lower and relatively stable from February through April, then began to increase and show high daily variability into October before moderating at the end of the year. The higher average summer prices reflect higher LMPs in the LOC portion of the marginal unit's RMCP for regulation. (See Figure 6-2, Figure 6-3 and Figure 6-4.) During a period of low prices, March and April, the LOC/RMCP ratio was 42 percent for the PJM Mid-Atlantic Region and 58 percent for the Western Region. During a period of high prices, August and September, the LOC/RMCP ratio was 83 percent for the PJM Combined Regulation Market.

Figure 6-8 illustrates the level of demand for regulation by month in 2005 and the corresponding level of regulation cost.

Figure 6-8 - Monthly regulation MW and regulation cost per MW: Calendar year 2005

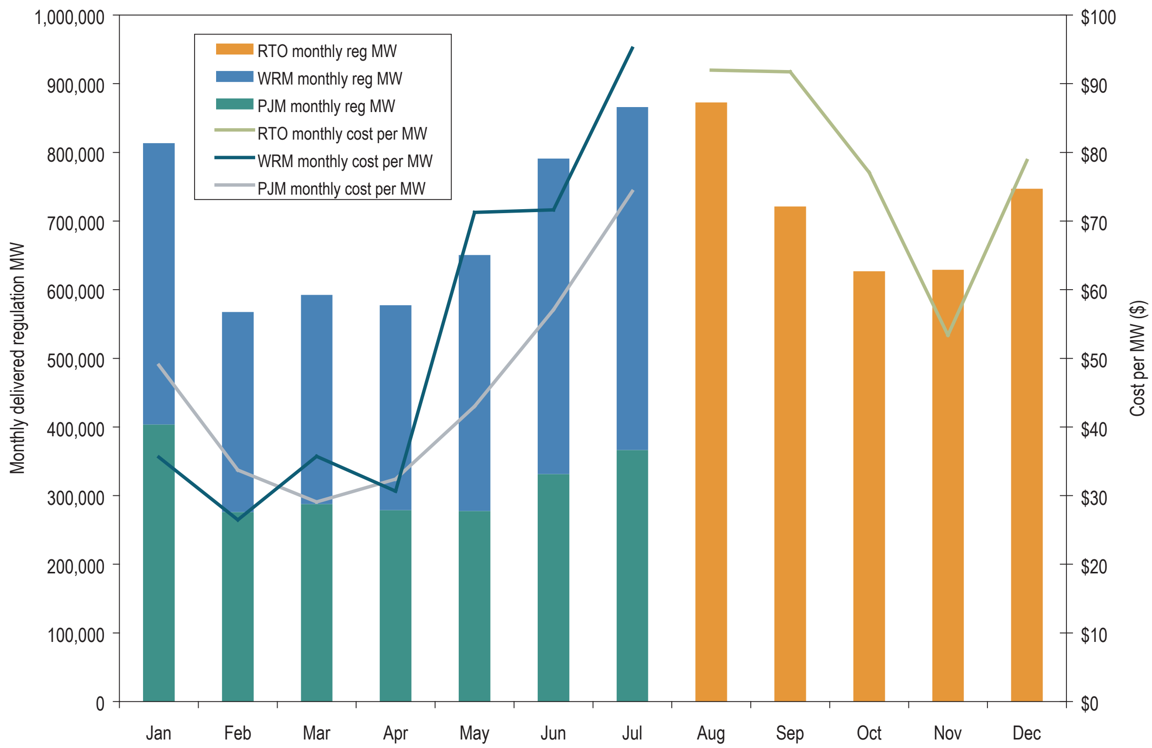
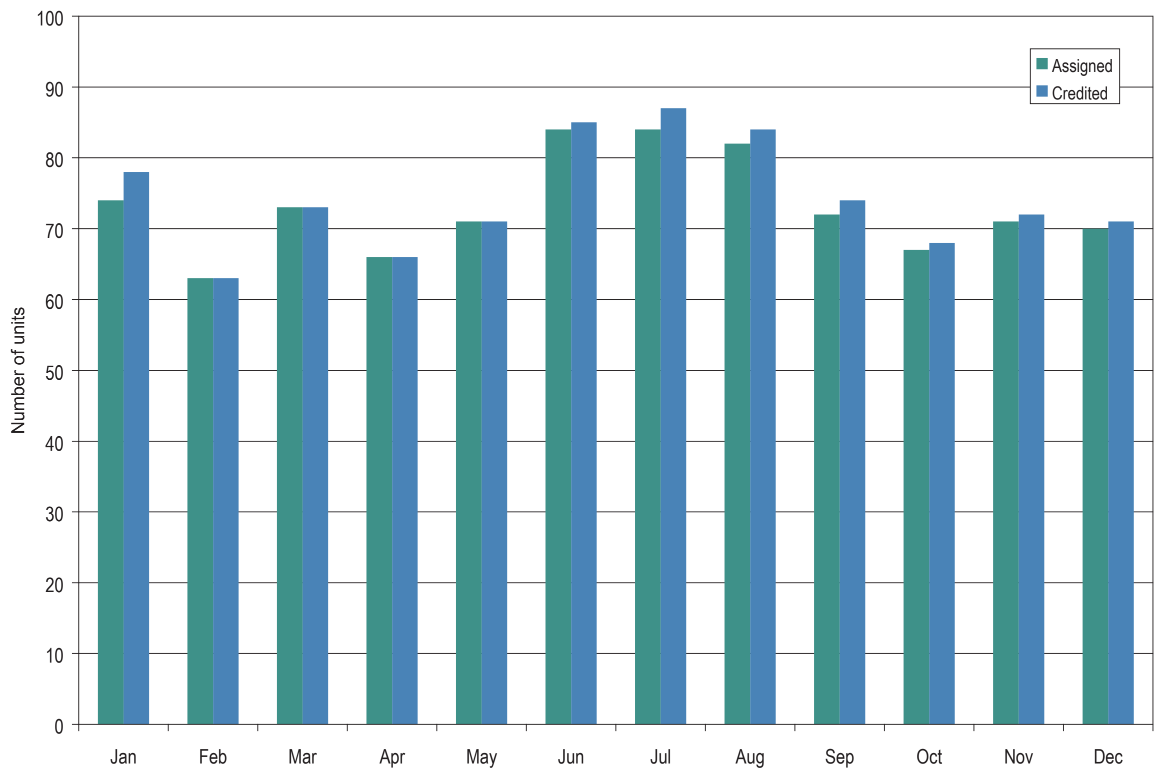


Figure 6-9 shows the average number of units per hour required to satisfy PJM's regulation requirement.

Figure 6-9 - Average hourly count of distinct units required to satisfy regulation requirement: Calendar year 2005



Units which provide regulation are paid the higher of the RMCP or their offer plus their unit-specific opportunity cost. In a perfect market all units would be compensated at RMCP times output. Sometimes, however, circumstances require that units be paid their offer plus their unit-specific opportunity cost. Examples include units that must be redispatched because of constraints, unanticipated performance problems, or changes in the real-time LMP and, therefore, opportunity cost from the value estimated at regulation market-clearing 30 minutes prior to the operating hour. For these reasons some units are paid the value of their offer plus their unit-specific lost opportunity costs when that sum is higher than the RMCP. This means that PJM's regulation cost per MWh is somewhat higher than the RMCP. Figure 6-10 and Figure 6-11 compare the regulation cost per MWh with the regulation clearing price to show the difference between the price of regulation and the total cost of regulation.

Figure 6-10 - PJM Western Region Regulation Market daily average RMCP vs. cost per MW for regulation: Phases 4 and 5-a

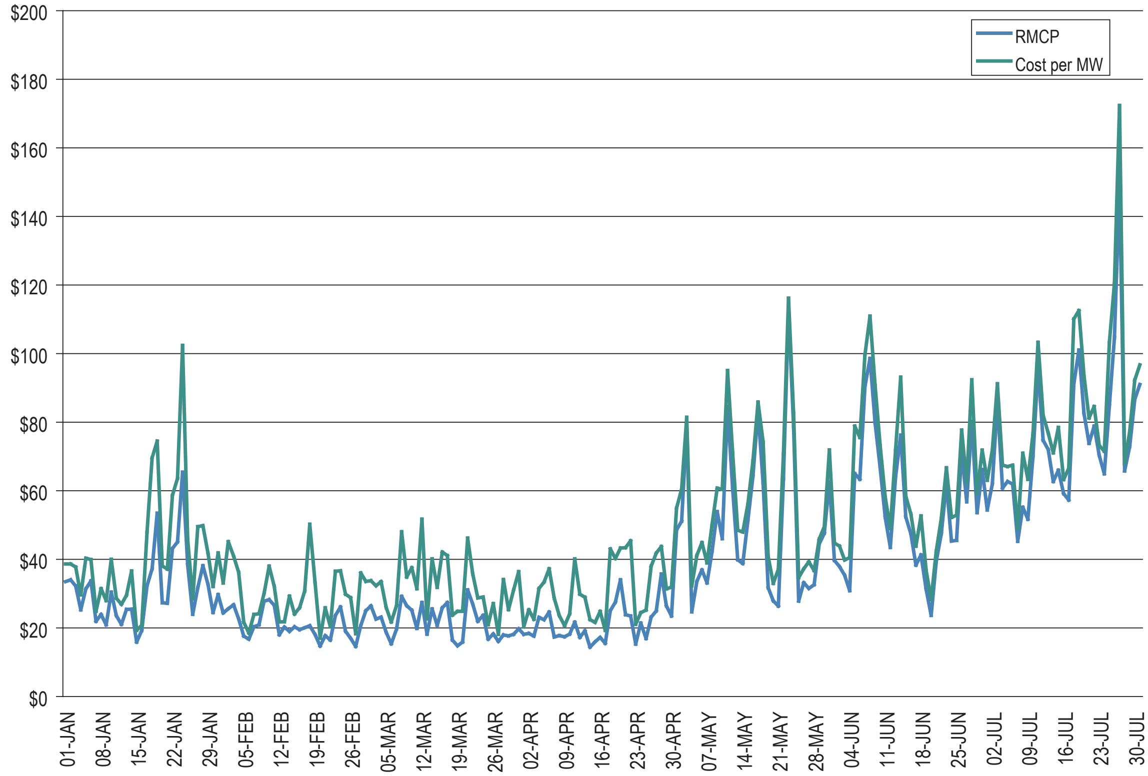
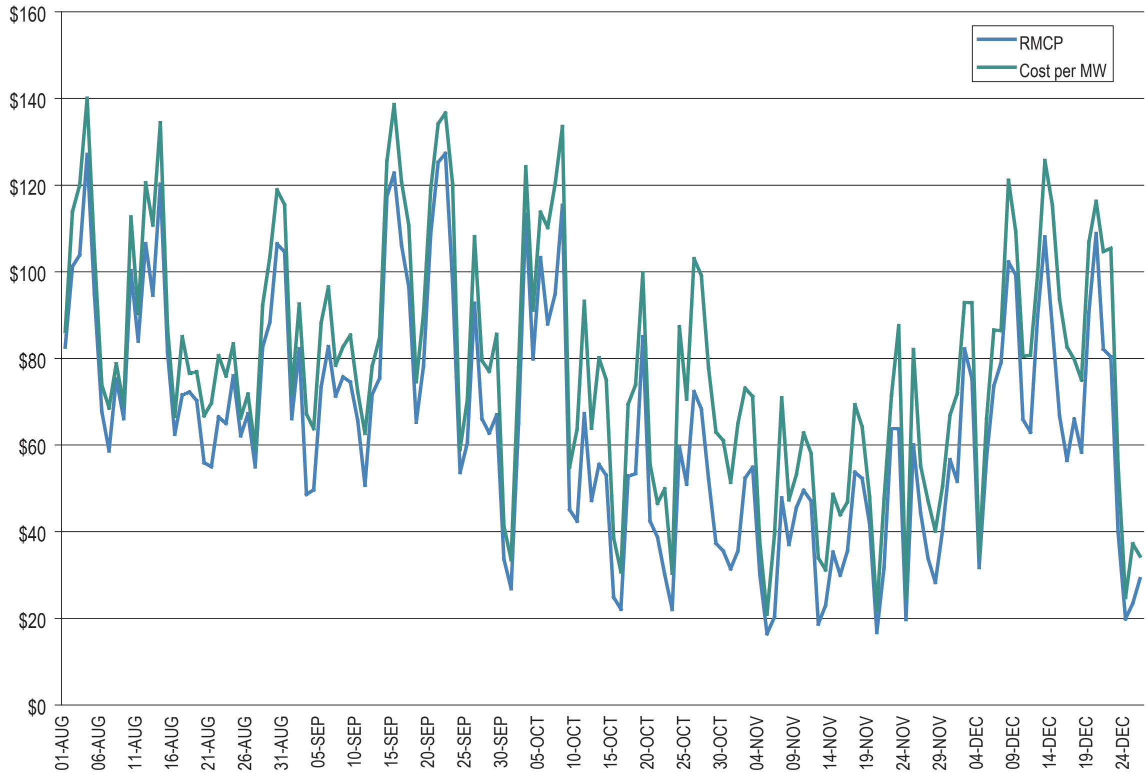


Figure 6-11 - PJM Combined Regulation Market daily average RMCP vs. cost per MW for regulation: Phase 5-b



Spinning Reserve Markets

Spinning Reserve Market Structure

The integration of Dominion on May 1, 2005, resulted in the creation of a Southern Region Spinning Reserve Market. Thus the PJM Spinning Reserve Markets include the PJM Mid-Atlantic Region Spinning Reserve Market, the Western Region Spinning Reserve Market, the ComEd Region Spinning Reserve Market and the Southern Region Spinning Reserve Market.

Demand

Tier 2 spinning requirements are determined by subtracting the amount of forecast Tier 1 spinning reserve available from each spinning control area spinning reserve requirement for the period. The total spinning reserve requirement is different for each of the four regional Spinning Reserve Markets. For the Mid-Atlantic Region, the requirement is 75 percent of the largest contingency in the region, provided that 25 percent of the largest contingency is available as nonsynchronized, 10-minute reserve. For the ComEd Region, 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. From October 1 to December 3, 2004, this was 269 MW. After December 3, 2004, the ComEd Control Zone's spinning requirement was 216 MW. For the Western Region, the requirement is 1.5 percent of the daily peak-load forecast. For the Southern Spinning Reserve Zone, 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 Southern Spinning Reserve Zone.

Computed in accordance with the requirements above, the average MW spinning requirement was: 1,091 MW, for the PJM Mid-Atlantic Region; 217 MW for the ComEd Spinning Zone; 437 MW for the Western Region; and 5 MW for the Southern Spinning Reserve Zone (May to December only).

Figure 6-12 - PJM Mid-Atlantic Spinning Region average hourly required spinning vs. Tier 2 spinning purchased: Calendar year 2005

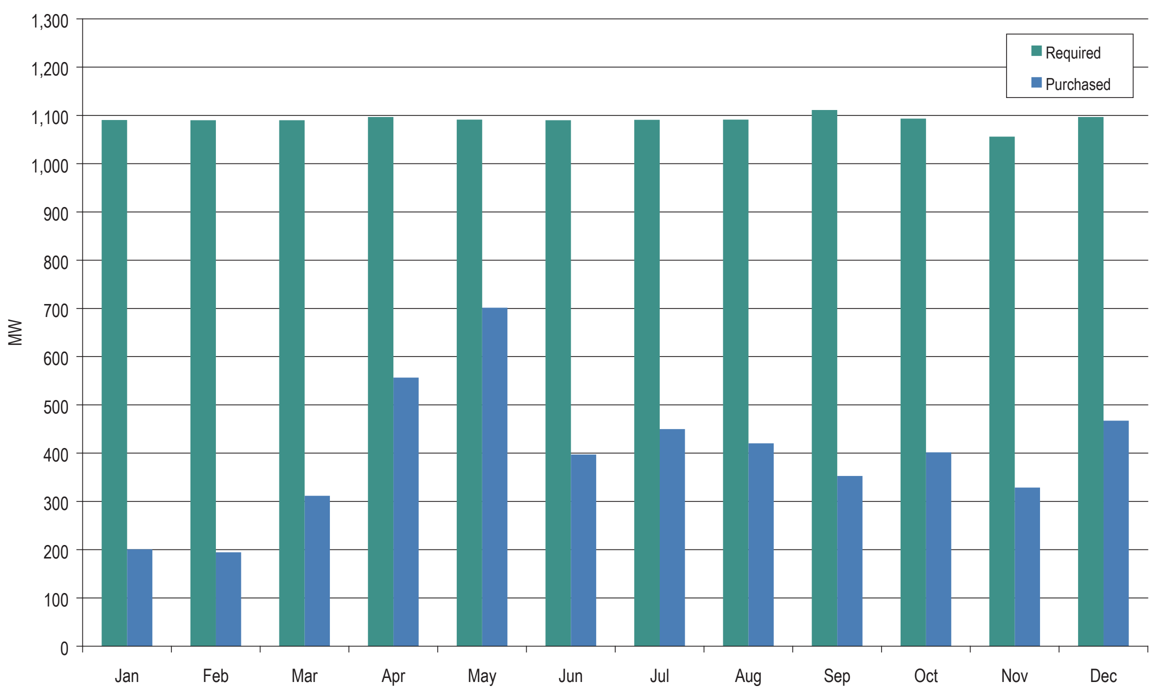


Figure 6-13 - PJM ComEd Spinning Region average hourly required spinning vs. Tier 2 spinning purchased: Calendar year 2005

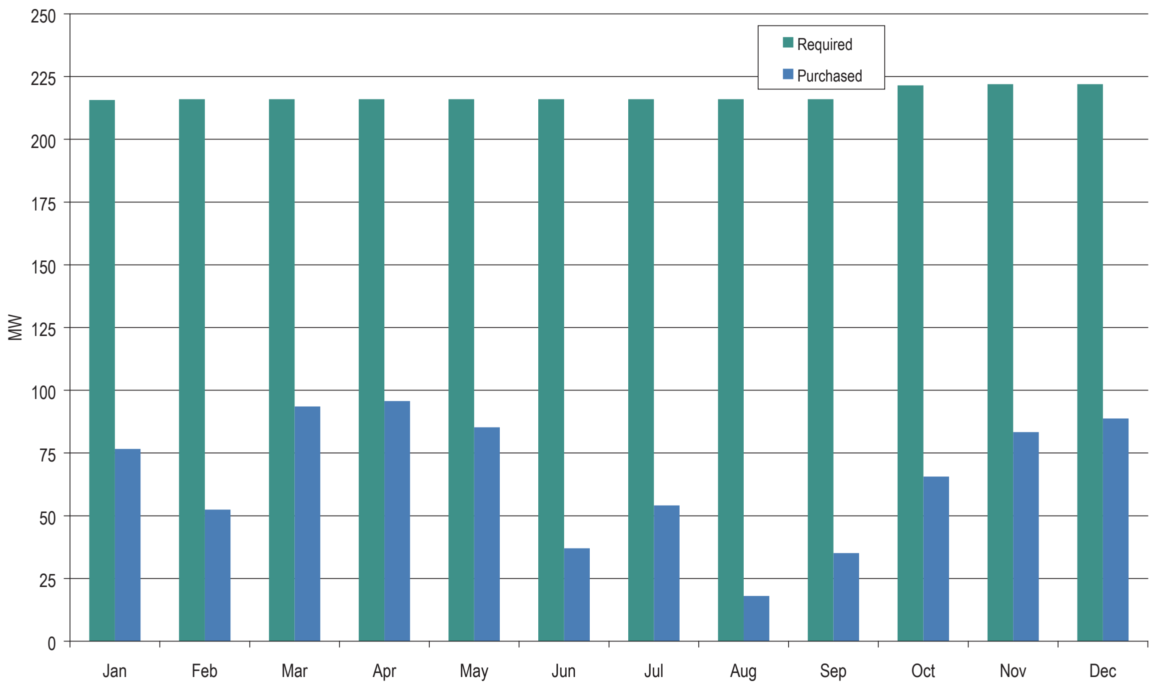
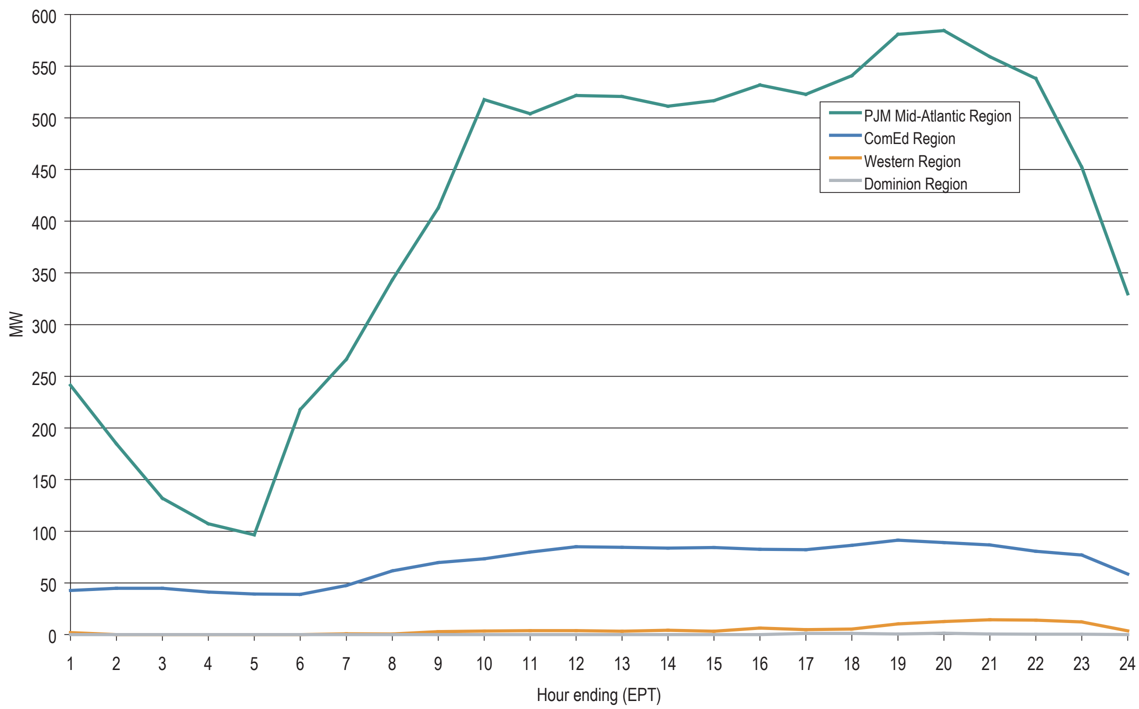


Figure 6-12 and Figure 6-13 show the average hourly spinning required and the average hourly Tier 2 spinning MW purchased during 2005 for the PJM Mid-Atlantic and ComEd Spinning Regions. Results for the Western Region Spinning Reserve Zone and the Southern Spinning Reserve Zone are not shown because Tier 2 spinning MW purchases were insignificant in those control areas during 2005. Spinning MW requirements are different for each of the four spinning regions in PJM. These differences are the result of specifications from local reliability councils, reserve-sharing arrangements with neighboring control areas and the types of generation available in the control area. The Southern Spinning Reserve Zone 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 the largest contingency to determine spinning reserve requirements. The amount of 15-minute quick start reserve available in VACAR is sufficient to make Tier 2 spinning requirements zero for most hours. Similarly, in the Western Region Spinning Reserve Zone most of the required spinning reserve is available as Tier 1 from large, frequently running baseload units, reducing its Tier 2 spinning requirement to zero in most hours. In both the PJM Mid-Atlantic and ComEd Spinning Regions the spinning reserve requirement is a function of the largest contingency. For the PJM Mid-Atlantic Region the hourly spinning requirement was usually 863 MW during off-peak hours and 1,150 MW 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 spinning requirement was 1,380 MW. The average hourly Tier 2 spinning required for the PJM Mid-Atlantic Region was 1,091 MW. In the ComEd Region, the hourly requirement was 216 MW from January through September and 222 MW from October through December. Figure 6-12 and Figure 6-13 illustrate monthly average of the spinning reserve requirement and the amount of Tier 2 spinning actually purchased. The difference between the required spinning and Tier 2 spinning purchased is the amount of Tier 2 spinning available. Figure 6-14 illustrates the amount of Tier 2 spinning purchased by hour of the day. The hour variability reflects differing spinning reserve requirements for off-peak and on-peak hours as well as different amounts of Tier 1 spinning available.

Figure 6-14 - Average hourly Tier 2 spinning MW purchased (By hour of day): Calendar year 2005



Supply

Spinning reserve is an ancillary service defined as generation that is synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can, at present, be provided by a number of sources, including steam units with available ramp, condensing hydroelectric units, condensing CTs and CTs running at minimum generation.

All of the units that participate in the Spinning Reserve Market are categorized as either Tier 1 or Tier 2 spinning. 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 spinning. Tier 2 resources include units that are backed down to provide spinning capability and condensing units synchronized to the system and available to increase output.

PJM introduced a market for spinning reserve on December 1, 2002. Before the Spinning Reserve Market, Tier 1 spinning reserve had not been compensated directly and Tier 2 spinning reserve had been compensated on a unit-specific, cost-based formula.

Under the Spinning Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed. Tier 1 spinning 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 spinning energy premium less the hourly integrated LMP. The spinning energy premium is defined as the average of the five-minute LMPs calculated during the spinning event plus $50 per MWh.[21] All units called on to supply Tier 1 or Tier 2 spinning 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. Tier 2 units assigned spinning by market operations are compensated whether or not they are actually called on to supply spinning so they are penalized if their MW output fails to meet their assignment.

There were significant changes to the geographic structure of PJM's Spinning Reserve Markets in 2005. In Phase 4, PJM had three Spinning Reserve Markets: the PJM Mid-Atlantic Spinning Reserve Zone, the Western Spinning Reserve Zone and the ComEd Spinning Reserve Zone. During Phase 4, the Western Spinning Reserve Zone was comprised of AP, AEP, DAY and DLCO Control Zones. In Phase 5, the Dominion Control Zone was integrated into PJM and became the Southern Spinning Reserve Zone. Dominion remained a separate Spinning Reserve Market because as a member of SERC it has distinct spinning reserve requirements and reserve-sharing agreements.

Under the Spinning Reserve Market rules, Tier 2 spinning resources are paid to be available as spinning 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 spinning reserve when called. The price for Tier 2 spinning resources is determined in a market for Tier 2 spinning resources. Several steps are necessary before the hourly Tier 2 Spinning 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 spinning requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit-order price of the highest price, Tier 2 resource needed to fulfill spinning requirements, the marginal unit.[22]

The spinning offer price submitted for a unit can be no greater than the unit's operating and maintenance cost plus a $7.50 per MWh margin.[23,24] The market-clearing price is comprised of the marginal unit's spinning offer price, the cost of energy use and the unit's opportunity cost. All units cleared in the Spinning Reserve Market are paid the higher of either the market-clearing price or the unit's spinning offer plus the unit-specific LOC and/or the cost of energy use incurred.

The Mid-Atlantic Region, the Western Region, the ComEd Region and the Southern Region Spinning Reserve Zones all operate under similar business rules. The Tier 2 Spinning Reserve Market in each of PJM's spinning reserve zones is cleared on cost-based offers because the structural conditions for competition do not exist. The structural issue can be more severe when the Spinning Reserve Market becomes local because of transmission constraints.

21 See "PJM Manual 11: Scheduling Operations," Revision 26 (November 9, 2005), pp. 66-69.

22 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price is 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.

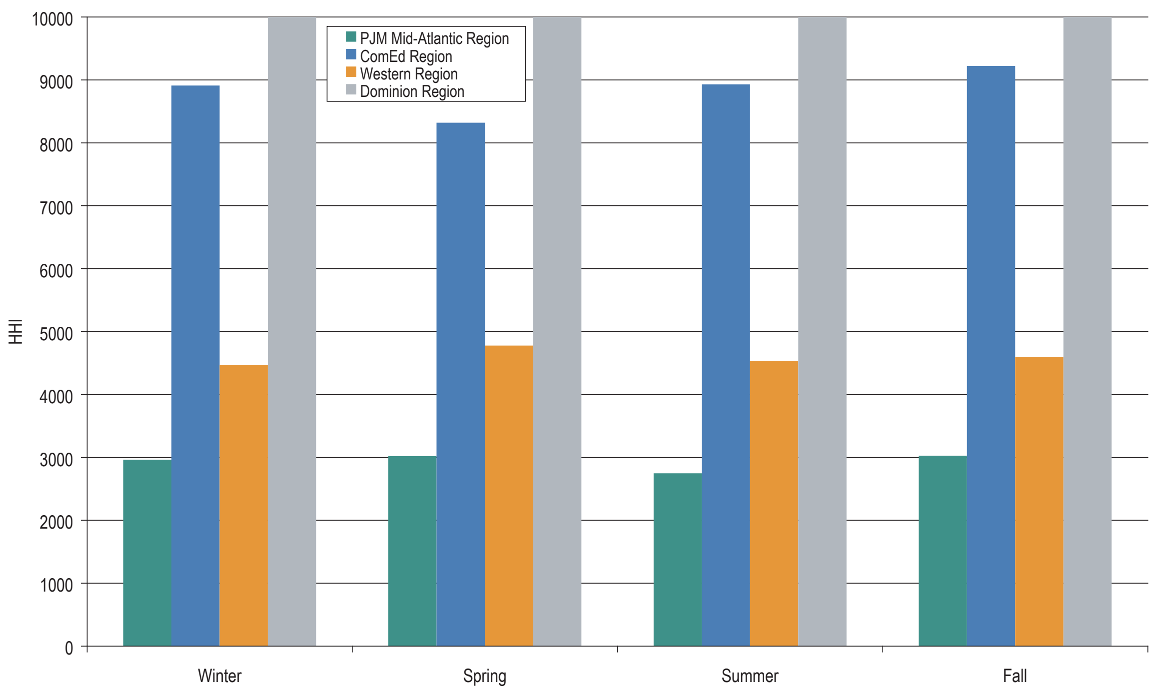
23 See "PJM Manual 11: Scheduling Operations," Revision 26 (November 9, 2005), p. 59.

24 See "PJM Manual 15: Cost Development Guidelines," Revision 6 (March 2, 2006), p. 35.

Concentration of Ownership

The offered and eligible Tier 2 Spinning Reserve Markets for all four geographic markets are highly concentrated. (See Figure 6-15.) During calendar year 2005, in the Mid-Atlantic Region average HHI for offered Tier 2 spinning was 2167 and 2940 for eligible spinning. In the ComEd Region during 2005 the average HHI for offered spinning was 6305 and 8844 for eligible spinning. In the Western Region the average HHI for offered spinning was 4173 and 4593 for eligible spinning. In the Southern Region the HHI was 10000.

Figure 6-15 - Eligible Spinning Reserve Market HHI: Calendar year 2005



Spinning Reserve Market Performance

Spinning Reserve Offers

Figure 6-16 shows the daily average hourly offered Tier 2 spinning. Figure 6-17 shows the daily average hourly eligible Tier 2 spinning. Daily Tier 2 spinning offers are fairly stable reflecting the Tier 2 spinning capability of the units, other unit attributes and economic decisions by sellers. The level of eligible spinning displays considerable variability because it is calculated hourly and reflects current market and grid conditions, including LMP, unit dispatch and system constraints.

Figure 6-16 - Tier 2 spinning offered MW: Calendar year 2005

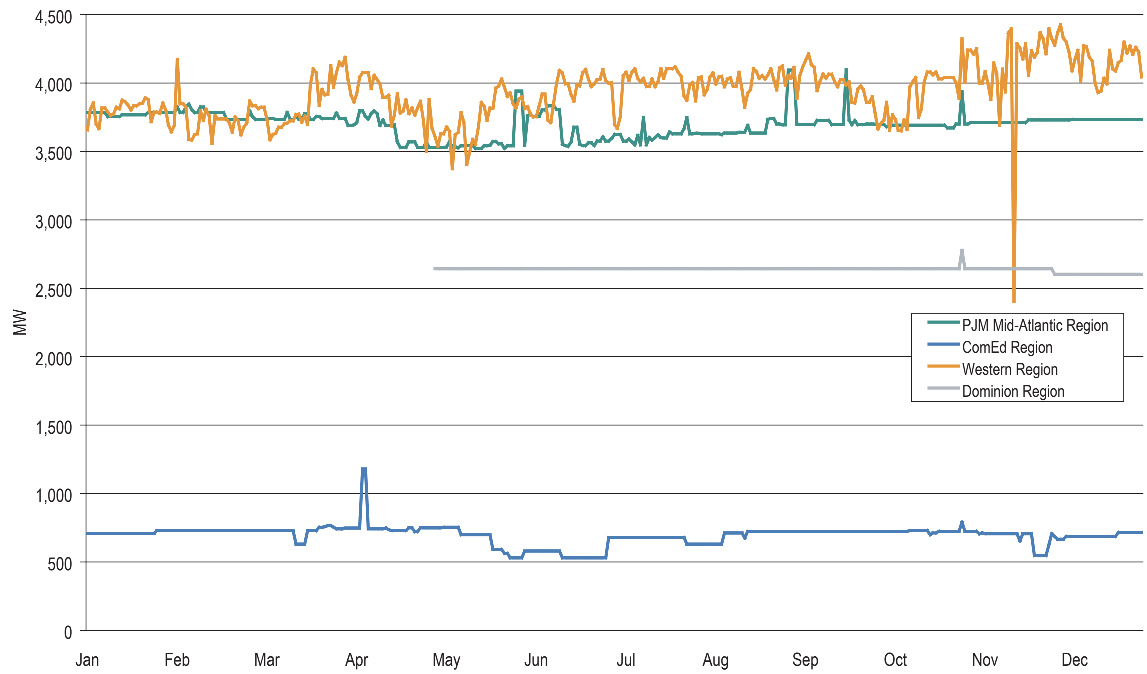


Figure 6-17 - Tier 2 spinning eligible MW: Calendar year 2005

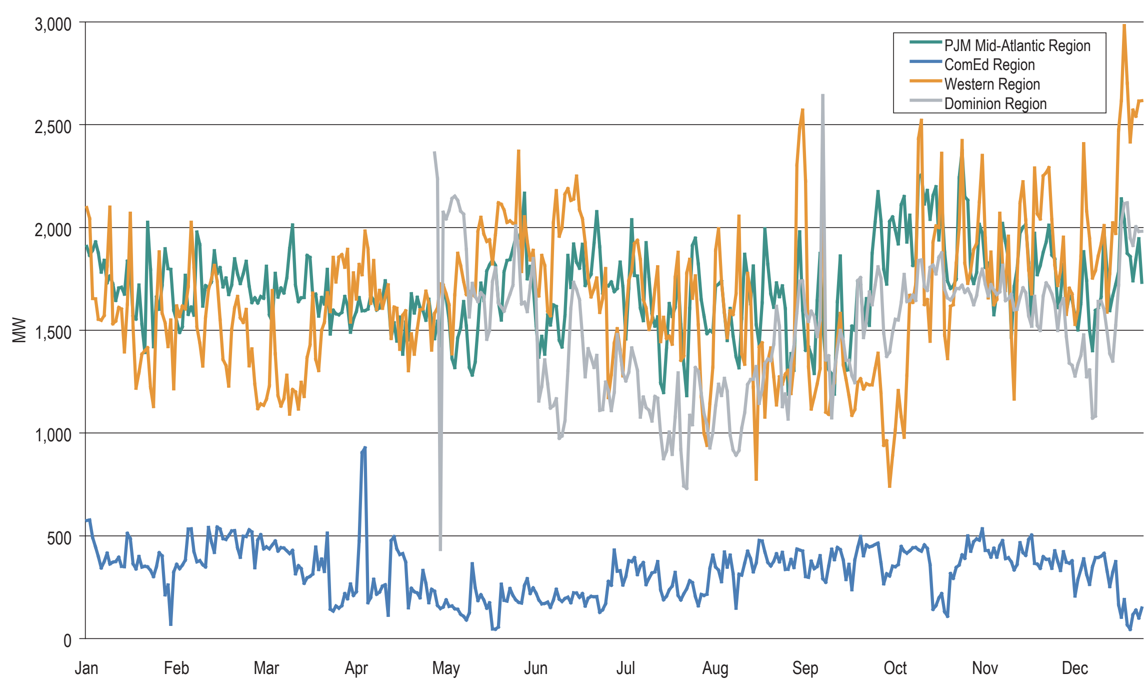
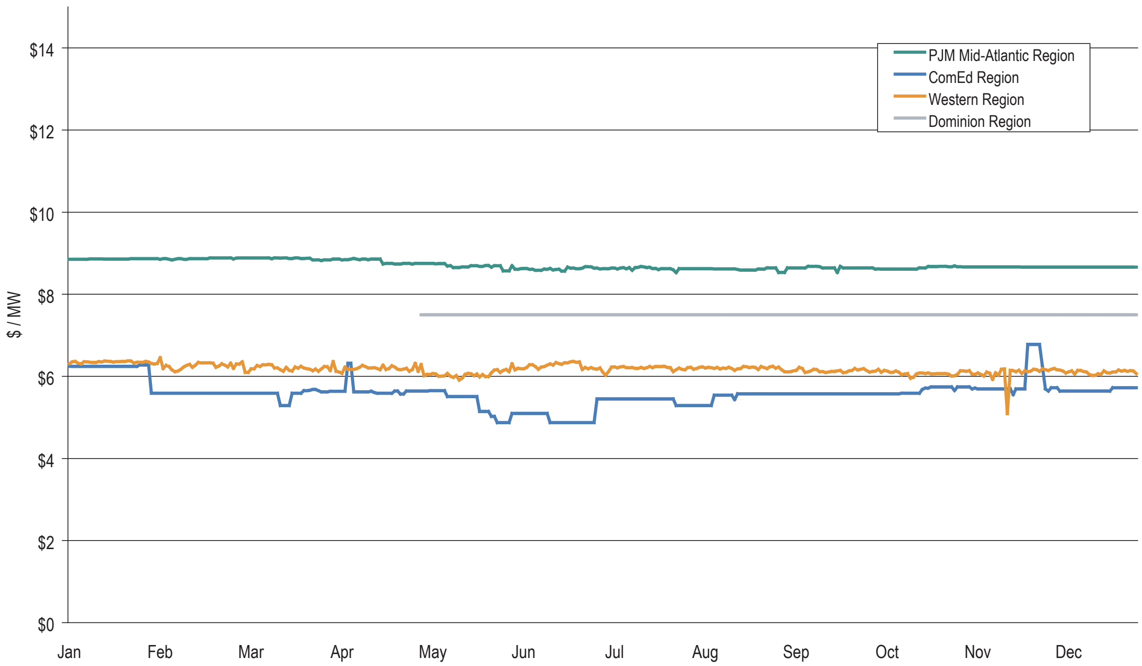


Figure 6-18 shows average offer price per MW by ancillary service area. Tier 2 spinning offers are capped at $7.50 plus costs. The clearing price for Tier 2 spinning includes lost opportunity costs based on LMP, energy use, and operating costs for units which are actually assigned Tier 2 spinning. (See Figure 6-19.)

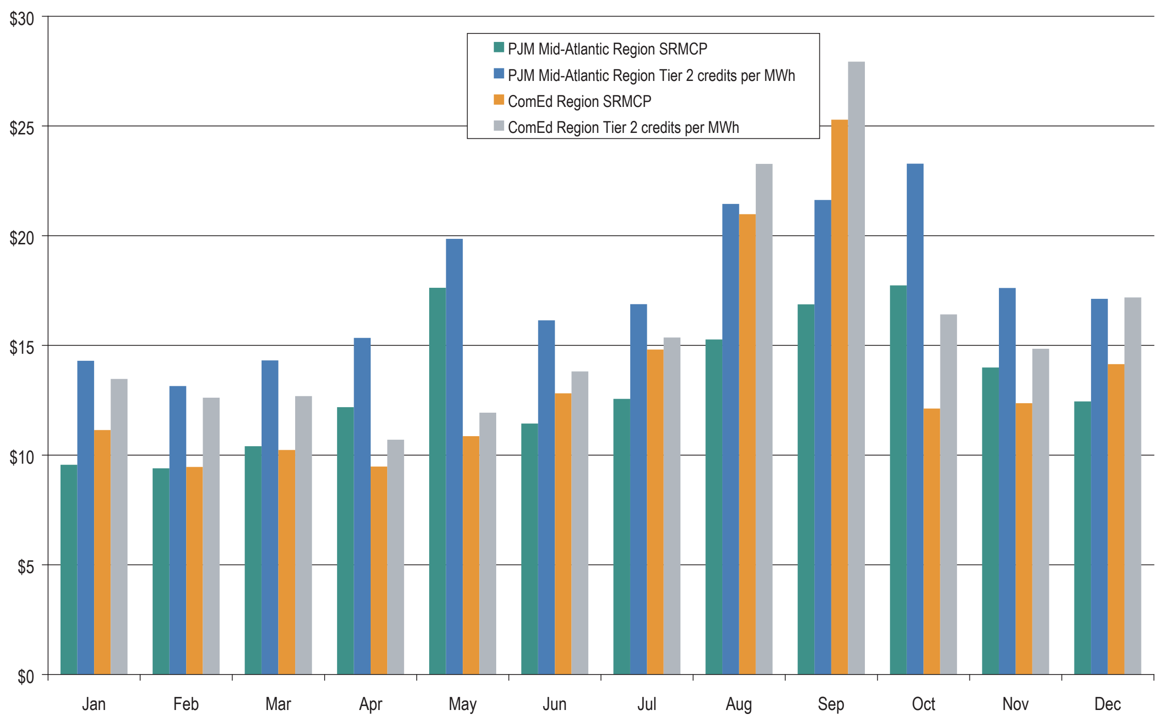
Figure 6-18 - Tier 2 spinning average offer price per MW: Calendar year 2005



Spinning Reserve Prices

Figure 6-19 shows the average spinning reserve market-clearing price (SRMCP) and the cost per MW associated with meeting PJM demand for spinning reserve. The average PJM Mid-Atlantic Region SRMCP rose in 2005 to $13.29. The cost per MW of meeting the spinning reserve requirements also rose to approximately $17.59 per MWh. In the ComEd Region, the average SRMCP was $13.64 and the cost per MW for meeting the spinning reserve requirement was $15.85. No price data are presented for the Western Region Spinning Reserve Market because there was almost always adequate Tier 1 spinning reserve to meet the requirements for spinning reserve without clearing the Tier 2 market.

Figure 6-19 - Tier 2 spinning market-clearing price and cost per MW: Calendar year 2005



The Western Region Spinning Reserve Market (not shown in Figure 6-19) during 2005 almost never had a clearing price because available Tier 1 spinning was always sufficient to cover the spinning requirement. For the 311 hours between June and December when a Spinning Reserve Market was cleared in the Western Region, the average clearing price was $12.27 and the cost of spinning was $66.75 per MWh. The Southern Region (not shown in Figure 6-19) was cleared only 18 hours between June 1 and December 31 with an average SRMCP of $11.34 and an average cost per MWh for Tier 2 spinning of $35.10.

Like Regulation Market prices, Tier 2 spinning reserve prices are more reflective of costs associated with the marginal unit than they are of offer prices. Unlike regulation, however, the costs in Tier 2 spinning are more than just opportunity costs; they are also energy costs for condensing MWh (which must be purchased from the Real-Time Energy Market when the unit is spinning), and startup costs if the assigned unit is not already running. Figure 6-20 and Figure 6-21 show the relationship between the marginal unit's offer price and the SRMCP. For the PJM Mid-Atlantic Region during all of 2005 the Tier 2 spinning offer price averaged 67 percent of the SRMCP.

Figure 6-20 - PJM Mid-Atlantic Region Tier 2 spinning reserve clearing prices and marginal unit offer price: Calendar year 2005

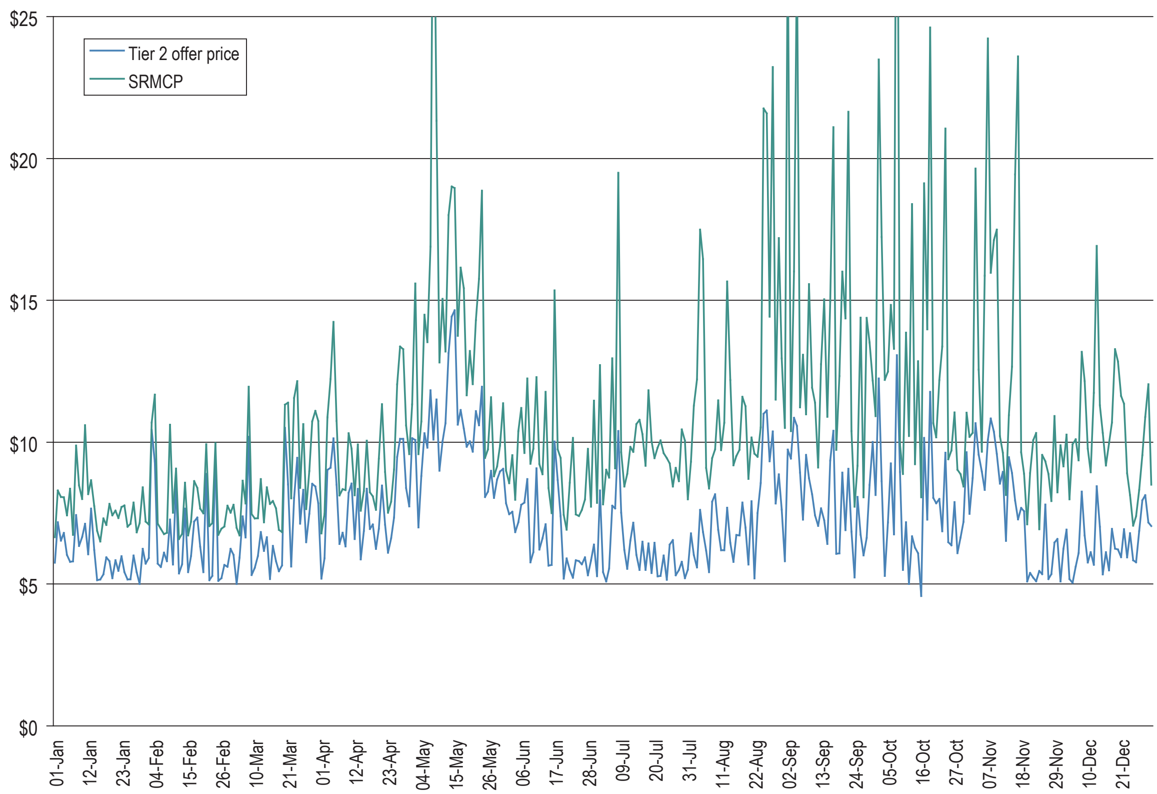


Figure 6-21 shows the relationship between the marginal units' offer price and the SRMCP for the ComEd Region. For the ComEd Region during all of 2005, the Tier 2 spinning offer price averaged 51 percent of the SRMCP.

Figure 6-21 - PJM ComEd Tier 2 spinning reserve clearing prices and marginal unit offer price: Calendar year 2005

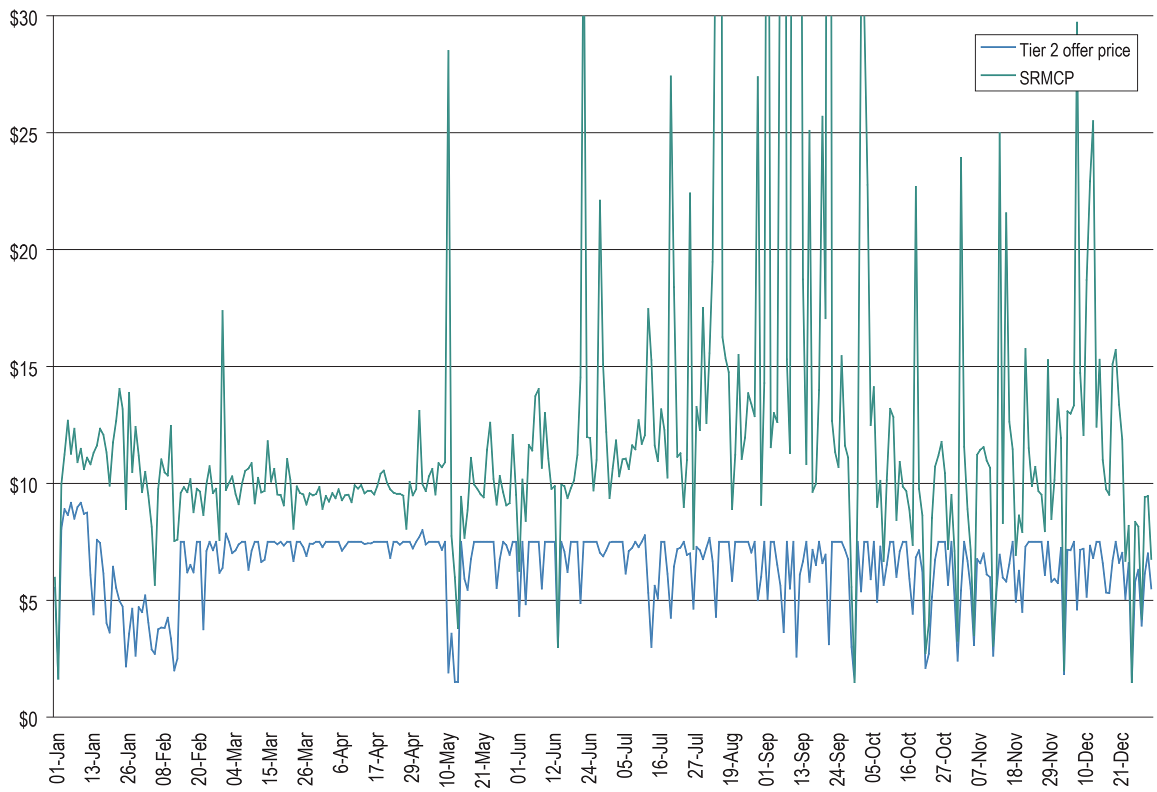
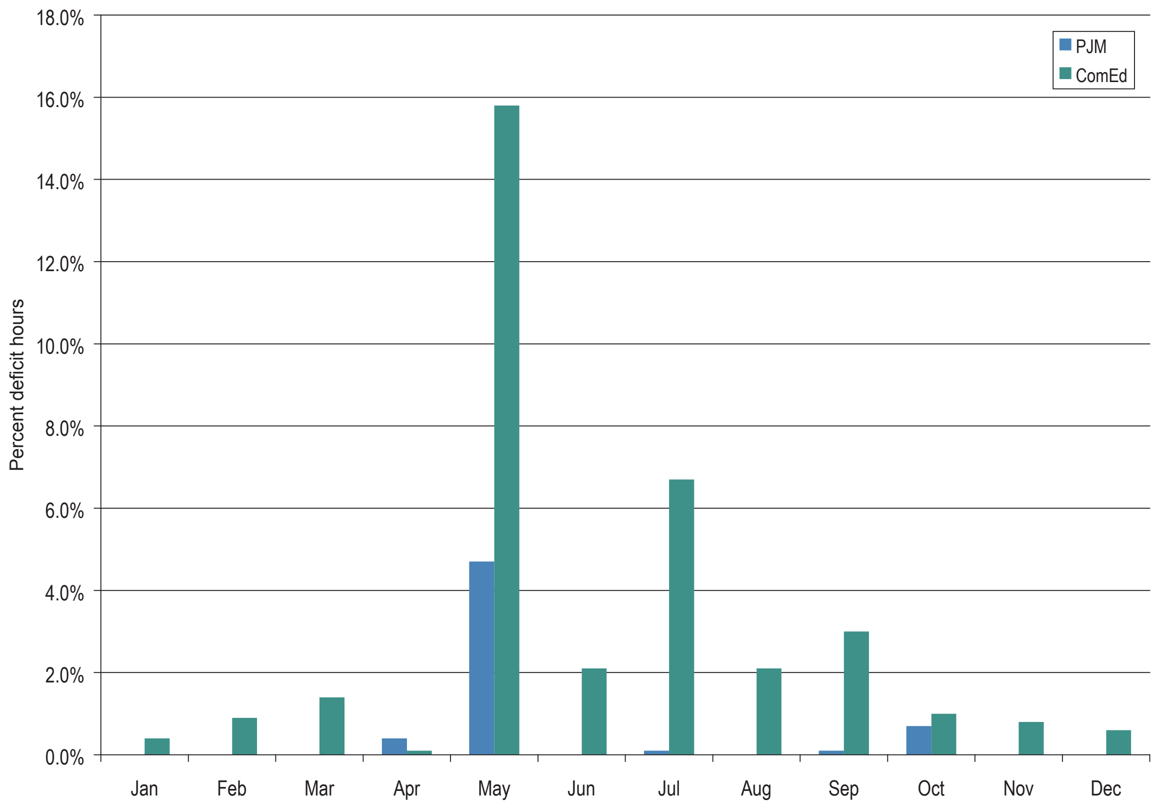


Figure 6-21 shows the level of Tier 1 and Tier 2 spinning reserve purchased from suppliers during calendar year 2005. Tier 1 resources are paid only if they respond during spinning events while Tier 2 resources are paid for providing hourly reserve. In general, more Tier 2 resources are purchased than Tier 1 resources, and Tier 2 payments are higher than Tier 1 payments. An important exception to this general rule was in the Western Region Spinning Reserve Market where a large baseload of available operating reserves ensures that Tier 1 spinning reserve services were almost always sufficient to cover the spinning requirement so Tier 2 spinning reserve was rarely purchased.

Spinning Reserve Availability

A spinning reserve deficit occurs when the combination of Tier 1 and Tier 2 spinning is not adequate to meet the spinning reserve requirement. Except for a brief period in the ComEd Region during May (See Figure 6-22.), none of PJM's Spinning Reserve Markets had significant spinning reserve deficits during 2005.

Figure 6-22 - Tier 2 Spinning Reserve Market deficits: Calendar year 2005



The Tier 2 spinning deficit peak during May in the ComEd Region was caused indirectly by a need for regulation and the assignment of several CTs, which otherwise provided spinning reserve to regulation. None of these Tier 2 spinning deficits created a serious problem because the ComEd Region's reserve requirement was satisfied by a reserve-sharing agreement with other members of MAIN.

SECTION 7 – CONGESTION

Congestion occurs when available, lower-cost energy cannot be delivered to all loads for a period because transmission capabilities are not adequate to meet some loads for the period. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in this 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 of pricing energy supply 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 a negative nor a positive but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized through the capability of the transmission system to deliver the cheapest energy to all parts of the system in every hour. A rational planning process would attempt to choose the least cost combination of transmission and generation and would reflect the fact that investments in both transmission and generation have costs. The transmission system provides one 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, FTRs are not a complete hedge against congestion, FTRs do provide a substantial offset to the cost of congestion to firm load.

As PJM integrated new transmission zones during 2005, the patterns of congestion changed, reflecting additional transmission and generation resources with new cost structures, load requirements and transmission system characteristics.

During the last two calendar years, PJM has 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. In the *2005 State of the Market Report* the calendar year is 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]

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 the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

3 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

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 the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

- **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.

Overview

Congestion Cost

- **Total Congestion.** Congestion costs have ranged from 6 percent to 10 percent of PJM annual total billings since 2000. Congestion costs were approximately 9 percent of total PJM billings for 2005, as they were in 2004. Total congestion costs were $2.09 billion in calendar year 2005, a 179 percent increase from $750 million in calendar year 2004. The increased size of the total PJM Energy Market contributed to the increase in total congestion charges. The total PJM billing for 2005 was $22.63 billion, a 160 percent increase over the approximately $8.70 billion billed in 2004.

- **Monthly Congestion.** Differences in monthly congestion costs continued to be substantial. In 2005, 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.** FTRs were paid at 100 percent of the target allocation level for the 12-month planning period that ended May 31, 2005. FTRs were paid at 91 percent of the target allocation level through December 31, 2005, of the planning period ending May 31, 2006.

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.

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).

- **Congested Facilities.** Congestion frequency increased in calendar year 2005 as compared to 2004. During 2005, there were 17,524 congestion-event hours as compared to 11,205 congestion-event hours in 2004. Interfaces, transformers and lines experienced overall increases in congested hours during 2005 as compared to 2004. The expansion of PJM through the integration of new control zones contributed to the increase in congestion frequency.

- **Zonal Congestion.** In calendar year 2005, the AP Control Zone experienced the largest increase in congestion frequency of any control zone in PJM. The 2,877 congestion-event hours in the AP Control Zone were a 746 percent increase over the 340 congestion-event hours the zone had experienced during 2004. The Doubs transformer and the Mount Storm-Pruntytown line together contributed 1,222 congestion-event hours or 42 percent of the AP Control Zone total. In the AECO Control Zone, there was a 119 percent increase in congestion on the Laurel-Woodstown 69 kV line. With 879 congestion-event hours, the Laurel-Woodstown line comprised 50 percent of all AECO Control Zone congestion during 2005. The AEP Control Zone saw increases in congestion on the Cloverdale-Lexington, Mahans Lane-Tidd and Kanawha-Matt Funk lines during 2005. These three facilities accounted for 1,357 congestion-event hours, or 71 percent of the total AEP Control Zone congestion during 2005. Congestion on 500 kV zone facilities increased in 2005 as compared to 2004, contributing 5,548 congestion-event hours or 32 percent of the total PJM congestion-event hours. Three 500 kV zone facilities, the Wylie Ridge transformer, Kammer transformer and the Bedington-Black Oak line contributed 4,045 congestion-event hours or 73 percent of all 500 kV zone congestion-event hours during 2005. The Wylie Ridge transformer, the Kammer transformer and the Bedington-Black Oak line were the first, second and third most frequently constrained facilities, respectively, during 2005.

Post-Contingency Congestion Management Program

- **Implementation.** PJM implemented a post-contingency congestion management protocol on September 1, 2004, under which a transmission facility may be operated to a 30-minute, short-term emergency rating if there is sufficient quick start generation capability or switching to respond to the loss of a facility.

- **Initial Results.** Beginning on June 1, 2005, there were 36 facilities included in this program, an increase of 21 facilities over the number as of June 1, 2004. During 2005, 136 hours of off-cost operation were avoided through the use of this protocol.

Economic Planning Process

- **Implementation.** PJM's regional transmission expansion planning (RTEP) process includes an economic planning component to identify the transmission upgrades needed to address unhedgeable congestion whether through a market window or directly through the RTEP process. However, the current methodology for calculating unhedgeable congestion overstates the value of economic generation as a congestion hedge unless economic local generation is owned by load. The result of such an overstatement is to undervalue the cost of unhedgeable congestion and to undervalue transmission upgrades. This, in turn, would lead to the rejection of cost-effective economic transmission upgrades under the cost-benefit calculation.

- **Early Results.** By December 31, 2005, 74 facilities had experienced sufficient levels of unhedgeable congestion to trigger the opening of a market window to solicit merchant solutions to relieve congestion. Of these, 31 or approximately 42 percent had completed their initial studies.

Conclusion

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 increased in 2005 in approximate proportion to the total increase in total billing as PJM continued to expand its footprint. The year 2005 was the first full calendar year reflecting the impact of areas integrated in 2004 in addition to the phased 2005 integrations of the DLCO and Dominion Control Zones. This constituted a dramatic change in the nature of the power system managed by PJM, including large new areas under LMP-based redispatch where borders had previously been managed by transmission loading relief (TLR) procedures and ramp limits. Efficient redispatch displaced the less efficient management of borders. That redispatch was more efficient and, at the same time, revealed the underlying limitations of the ability of the transmission system over the broad footprint 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 for the first time, is an essential input to a rational market and planning process that covers the entire expanded footprint for the first time. PJM has made significant steps in the transmission planning process and needs to make more, in particular ensuring that the calculation of the costs and benefits of congestion is done appropriately. With all the changes, ARRs and FTRs continued to serve as a hedge against congestion. FTRs were paid at 100 percent of their target allocation for the planning year ended May 31, 2005, and at 91 percent for the first seven months of the current planning year.

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Markets. Transmission congestion charges in the Day-Ahead Energy Market can be directly hedged by FTRs. Real-time 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.

Total congestion charges are the sum of the implicit and explicit day-ahead and balancing congestion charges, plus the day-ahead and balancing congestion charges implicitly paid in the Spot Market, minus any negatively valued FTR target allocations.[6]

- **Implicit Congestion Charges.** These charges are incurred by network service customers in delivering their generation 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 are similarly calculated as the sum of

6 See PJM manual, "Operating Agreement Accounting (m28), Revision 31" (November 1, 2005) p. 57.

the supply at every bus times the bus LMP, where supply includes generation, increment bids and purchase transactions. In the Real-Time Energy Market, load charges and generation credits are calculated the same way, using the differences between day-ahead and real-time demand and supply and valuing congestion using real-time LMP.

- **Explicit Congestion Charges.** These charges are incurred by point-to-point transactions and are equal to the product of the transacted MW and LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Real-Time Energy Market explicit congestion charges are equal to 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.** These charges are equal to the difference between total Spot Market purchase payments and total Spot Market sales revenues.

Total Calendar Year Congestion

Previously, state of the market reports have shown FTR revenues as congestion charges. While congestion charges are the primary source of funding to meet FTR target allocations, they are only a part of total FTR funding. Here, congestion charges and FTR revenues are reported separately. 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 1999 and 2002, equal in 2000 and 2001, and less than FTR revenues in 2003 through 2005. (See Table 7-1 and Table 7-2.) Table 7-3 shows the detail for calendar year 2005 of the components of FTR revenues including congestion charges and other adjustments.

Table 7-1 shows that FTR revenues have ranged from 6 percent to 9 percent of total annual PJM billings since 2000.[7] Though FTR revenues increased by 166 percent in 2005 as compared to 2004, they remained at approximately 9 percent of total PJM billings in 2005. The total PJM billing for 2005 was $22.63 billion, a 160 percent increase over the $8.7 billion billed in 2004.

Table 7-1 - Total annual PJM FTR revenues [Dollars (millions)]: Calendar years 1999 to 2005

	FTR Revenues	Percent Increase	Total PJM Billing	Percent of PJM Billing
1999	$53	NA	NA	NA
2000	$132	149%	$2,300	6%
2001	$271	105%	$3,400	8%
2002	$430	59%	$4,700	9%
2003	$499	16%	$6,900	7%
2004	$808	62%	$8,700	9%
2005	$2,146	166%	$22,630	9%
Total	$4,286		$48,630	9%

7 Total FTR revenues calculation in Table 7-1 excludes calendar year 1999.

Congestion charges are comprised of hourly congestion revenue and net negative congestion. Congestion costs have ranged from 6 percent to 10 percent of annual total PJM billings since 2000.[8] Though congestion costs increased by 179 percent in 2005 as compared to 2004, they remained at approximately 9 percent of total PJM billings in 2005 as they were during 2004. Table 7-2 shows total congestion by year from 1999 through 2005. Total congestion costs were $2.092 billion in calendar year 2005, a 179 percent increase from $750 million in calendar year 2004. The total PJM billing for 2005 was $22.63 billion, a 160 percent increase over the $8.7 billion billed in 2004.

Table 7-2 - Total annual PJM congestion [Dollars (millions)]: Calendar years 1999 to 2005

	Congestion Charges	Percent Increase	Total PJM Billing	Percent of PJM Billing
1999	$65	NA	NA	NA
2000	$132	103%	$2,300	6%
2001	$271	106%	$3,400	8%
2002	$453	67%	$4,700	10%
2003	$464	2%	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
Total	$4,163		$48,630	9%

Table 7-3 shows the composition of FTR target allocations and FTR revenues for calendar year 2005.[9] 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 uses, another component of FTR revenues, arise from 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 the provision of transmission service in connection with transactions not scheduled directly or otherwise prearranged between them. During 2005, competing uses accounted for a transfer of $1.8 million from NYISO to PJM. Total congestion charges appearing in Table 7-2 include both congestion associated with PJM facilities and that associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM. The Joint Operating Agreement (JOA) between the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and PJM sets forth conditions under which congestion charges associated with these reciprocal, coordinated flowgates are reimbursed through payments between the two transmission operators.[10] These payments, which began in April 2005, resulted in a net transfer of $21.6 million to Midwest ISO during calendar year 2005. The operating protocol governing the wheeling contracts between PSEG and Consolidated Edison resulted in a reimbursement of $2.1 million in congestion charges to Consolidated Edison during calendar year 2005, with payments beginning during July.[11] The congestion

8 The total congestion charges calculation in Table 7-2 excludes calendar year 1999.

9 Values in Table 7-3 are calculated using underlying data and may, therefore, not sum precisely as shown.

10 See the Joint Operating Agreement between the Midwest ISO and PJM, Substitute Original Sheet No. 66 <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (2.8 MB).

11 111 FERC ¶ 61,228 (2005).

payouts associated with both the PJM and Midwest ISO Joint Operating Agreement and the operating protocol governing the wheeling contracts between PSEG and Consolidated Edison served to decrease the revenues available to fund the FTR target allocations by $23.7 million during 2005.

Table 7-3 - Total annual PJM FTR revenue detail: Calendar year 2005

ARR Information		Total
ARR Target Allocations	$	653,148,924
FTR Auction Revenue	$	685,870,922
ARR Excess	$	32,721,999
FTR Targets		
FTR Target Allocations	$	2,247,880,993
Adjustments:		
Adjustments to FTR Target Allocations	$	(427,827)
Total FTR Targets	$	2,247,453,166
FTR Revenues		
ARR Excess	$	32,721,999
Competing Uses	$	1,806,387
Net Negative Congestion (Enter as Negative)	$	(10,420,565)
Hourly Congestion Revenue	$	2,101,960,789
Midwest ISO M2M (Credit to PJM Minus Credit to Midwest ISO)	$	(21,634,226)
CEPSW Wheel Congestion Credit (Hourly) (Enter as Negative)	$	(2,110,021)
Adjustments:		
Excess Revenues Carried Forward Into Future Months	$	45,891,816
Excess Revenues Distributed Back to Previous Months	$	-
Other Adjustments to FTR Revenues	$	(1,750,878)
Total FTR Revenues	$	2,146,465,301
Excess Revenues Distributed to Other Months	$	(64,795,613)
Excess Revenues Manually Distributed to Firm Demand Holders	$	(8,987,886)
Total FTR Congestion Credits	$	2,072,681,802
Total Congestion Credits on Bill (Includes CEPSW & End-of-Year Distribution)	$	2,083,781,395
Remaining Deficiency	$	174,771,365

Monthly Congestion

Table 7-4 shows monthly congestion charge variations by year.[12] During calendar year 2005, monthly congestion charges ranged from a maximum of $334 million in August 2005 to a minimum of $57 million in March 2005.

Table 7-4 - Monthly PJM congestion revenue statistics [Dollars (millions)]: Calendar years 2004 and 2005

	Maximum	Mean	Median	Minimum	Range
2004	$154	$63	$55	$18	$135
2005	$334	$174	$161	$57	$277

Approximately 22 percent of all calendar year 2005 congestion occurred during the summer and winter high-demand months of July and January.

Hedged Congestion

Table 7-5 lists FTR Revenues, FTR target allocations and credits, payout ratios, and congestion credit deficiencies and excess congestion charges by month.[13] 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, 2005, and will end on May 31, 2006.

12 Values in Table 7-4 are calculated using underlying data and may, therefore, not sum precisely as shown.
13 Values in Table 7-5 are calculated using underlying data and may, therefore, not sum precisely as shown.

Table 7-5 - Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period

		FTR Revenues	FTR Target Allocations	FTR Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Planning Year 2004 to 2005	Jun-04	$67	$67	$67	100%	$0	$0
	Jul-04	$116	$114	$114	100%	$0	$1
	Aug-04	$128	$128	$128	100%	$0	$0
	Sep-04	$47	$47	$47	100%	$0	$0
	Oct-04	$46	$39	$39	100%	$0	$7
	Nov-04	$81	$81	$81	100%	$0	$0
	Dec-04	$159	$150	$150	100%	$0	$8
	Jan-05	$144	$118	$118	100%	$0	$26
	Feb-05	$80	$65	$65	100%	$0	$15
	Mar-05	$75	$59	$59	100%	$0	$16
	Apr-05	$88	$80	$80	100%	$0	$8
	May-05	$88	$79	$79	100%	$0	$9
	Total	$1,118	$1,028	$1,028	100%	$0	$91
	Values After Excess Revenues Distributed						
		$1,118	$1,028	$1,028	100%	$0	$91
Planning Year 2005 to 2006 (through December 31, 2005)	Jun-05	$180	$187	$180	97%	$7	$0
	Jul-05	$319	$326	$319	98%	$7	$0
	Aug-05	$335	$336	$335	99%	$2	$0
	Sep-05	$224	$259	$224	86%	$35	$0
	Oct-05	$224	$280	$224	80%	$57	$0
	Nov-05	$108	$143	$108	75%	$35	$0
	Dec-05	$282	$315	$282	90%	$33	$0
	Total	$1,672	$1,847	$1,672	91%	$175	$0

FTRs were paid at 100 percent of the target allocation level for the 12-month planning period that ended May 31, 2005. FTRs through December 31, 2005, of the planning period ending May 31, 2006, have been paid at 91 percent of the target allocation level to date.

Although aggregate FTRs provided a hedge against 100 percent of the target allocation level during the 12-month period that ended May 31, 2005, 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

Constraints were examined by zone and categorized by their effect on regions as well as subareas. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones, and subareas consist of portions of one or more zones. At the end of 2005, PJM was comprised of three regions composed of the PJM Mid-Atlantic Region with 11 control zones, the PJM Western Region with five control zones: the AP, ComEd, AEP, DLCO and DAY Control Zones and the Southern Region with the Dominion Control Zone.

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 Figure 7-1 for calendar years 2002 through 2005, and were calculated as the difference between zonal LMP and the Western Hub LMP.

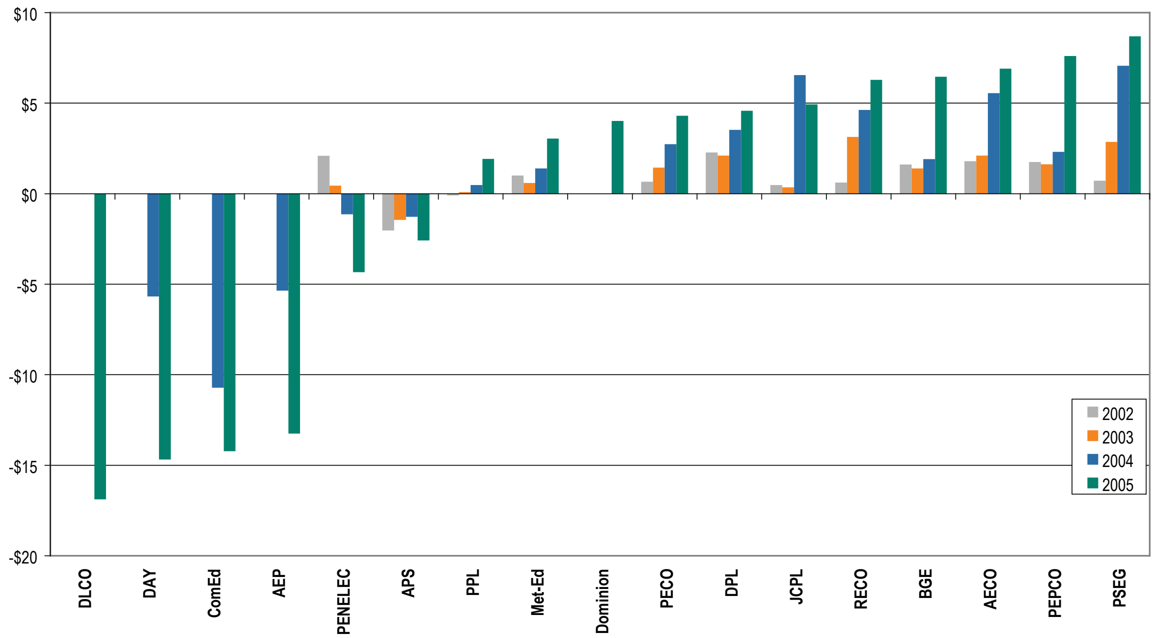
Figure 7-1 shows overall congestion patterns in 2005. Price separation between eastern and western zones in PJM was driven by congestion on the Bedington-Black Oak line and the Kammer and Wylie Ridge transformers. These constraints generally had the effect of increasing prices in eastern zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western zones. The Bedington-Black Oak constraint had the effect of increasing prices in all but the PENELEC, ComEd, AEP, DAY and DLCO Control Zones where it reduced prices. The Wylie Ridge transformer constraint had the effect of increasing prices in all but the ComEd, AEP, DAY and DLCO Control Zones where it reduced prices. The Kammer transformer constraint had the effect of increasing prices in all but the ComEd, AEP and DAY Control Zones where it reduced prices.

The Cedar Grove-Roseland constraint had the effect of decreasing prices in control zones located on the unconstrained side of this facility. Owing to the location of Cedar Grove-Roseland in the far eastern portion of PJM, prices in all control zones with the exception of the PSEG Control Zone decreased during this constraint.

The DLCO Control Zone exhibited an average negative price differential relative to the Western Hub of approximately $17 per MWh. The Wylie Ridge transformer and Bedington-Black Oak constraints caused the greatest decrease in prices in the DLCO Control Zone. The Dominion Control Zone, during the eight months from its May 1, 2005, integration until the end of the calendar year, exhibited an average differential of approximately $4 per MWh. The Bedington-Black Oak and Mount Storm-Pruntytown constraints caused the greatest increase in prices in the Dominion Control Zone relative to the Western Hub. The AEP and DAY Control Zones, which were integrated during Phase 3, continued to exhibit lower prices than the PJM Western Hub. The AEP and DAY Control Zones exhibited an average differential of approximately $13 per MWh and $15 per MWh, respectively, relative to the PJM Western Hub during 2005. The Kammer and Wylie Ridge transformer constraints caused the greatest decrease in prices in the AEP and DAY Control Zones relative to the Western Hub.

The BGE and PEPCO Control Zones exhibited an average differential of approximately $6 per MWh and $8 per MWh, respectively, relative to the PJM Western Hub during 2005. The Bedington-Black Oak constraint caused the greatest increase in prices in the BGE and PEPCO Control Zones relative to the Western Hub.

Figure 7-1 - Annual average zonal LMP differences (Reference to Western Hub): Calendar years 2002 to 2005



Congested Facilities

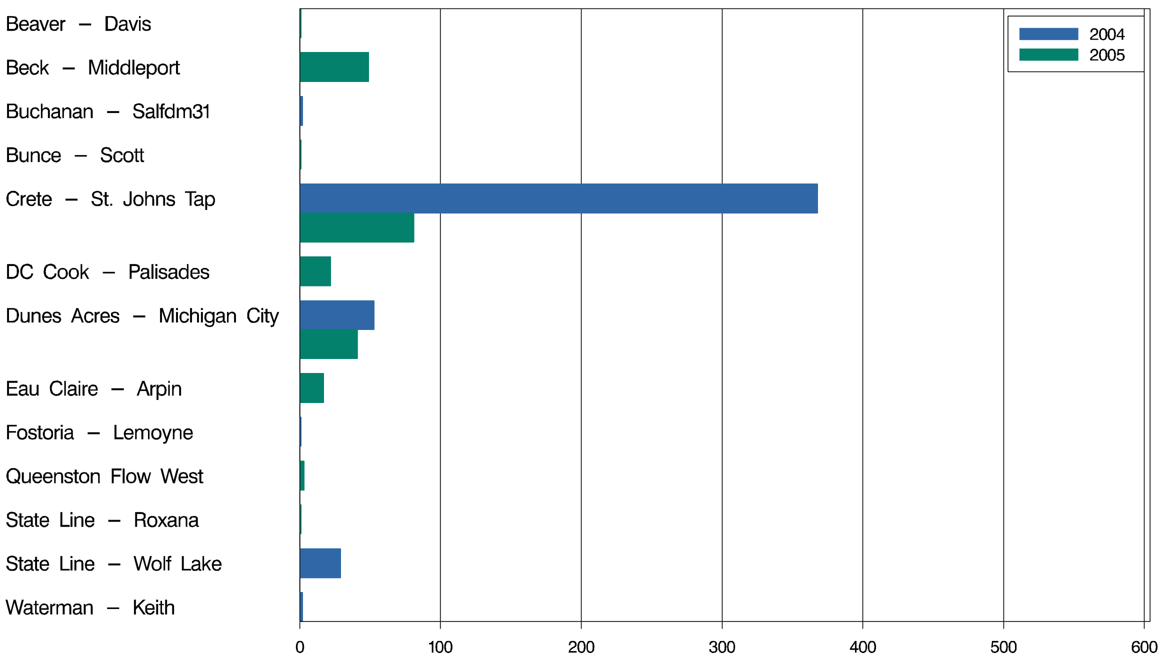
A congestion event exists when a unit or units must be dispatched out-of-merit order to control the impact of a contingency on a monitored facility or to control an actual overload. Congestion-event hours refer to the total number of congestion hours for a particular facility. A congestion-event hour differs from a constraint hour which is any hour during which one or more facilities are congested. Constraints are often simultaneous and, therefore, total congestion-event hours can exceed the number of hours in a year. Congestion frequency reported in this section follows 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. These five-minute intervals need not be consecutive within the hour. During calendar year 2005, 306 monitored facilities were constrained, 121 more than had been constrained during 2004. In 2005, there were 17,524 congestion-event hours, a 56 percent increase from 11,205 in 2004. Included in the total for 2004 were 2,512 congestion-event hours associated with the Phase 2 transmission Pathway between PJM and the ComEd Control Area before the integration of the AEP and DAY Control Zones in Phase 3.

Before Phase 2 integration began, PJM and the Midwest ISO had developed a JOA[14] which defines a coordinated methodology for congestion management. This protocol establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by both operators. A flowgate is a single or group of transmission elements intended to model MW flow and its impact on transmission limitations and transmission service usage.[15] PJM models these coordinated flowgates and controls for them in its security-constrained economic dispatch. To date, the most significant of these has been the Crete–St. Johns Tap line located near the southern tip of Lake Michigan. The Crete–St. Johns Tap line

14 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM" (March 1, 2004). The agreement is referred to here as the JOA.
15 See NERC Operating Manual, "Flowgate Administration Reference Document," Version 1 (March 21, 2002).

accounted for 81 of the 216 congestion-event hours caused by Midwest ISO flowgates during 2005. Midwest ISO flowgates accounted for 1.2 percent of the total PJM congestion-event hours during 2005. Figure 7-2 shows the number of hours during which PJM took dispatch action to control various Midwest ISO flowgates during calendar year 2005.

Figure 7-2 - Congestion-event hours (By facility) for Midwest ISO flowgates impacting PJM dispatch : Calendar years 2004 to 2005



Congestion by Facility Type

The total number of PJM congestion-event hours increased by about 56 percent to 17,524 hours in 2005 from 11,205 hours in 2004. The 2005 increase in congestion-event hours was attributable to increases on several 500 kV facilities and the expansion of PJM with the integrations of DLCO on January 1, 2005, and Dominion on May 1, 2005. As new control zones were integrated in 2004 and 2005, both the number of monitored transmission facilities and the number of constrained facilities increased simply due to the expanded PJM market footprint.

Congestion frequency on transformers, lines and interfaces all showed increases compared to 2004 levels. The Wylie Ridge transformer and Bedington-Black Oak line in the AP Control Zone and the Kammer transformer in the AEP Control Zone together accounted for 4,045 congestion-event hours or 23 percent of total PJM congestion-event hours in 2005.

Congestion frequency on Midwest ISO flowgates decreased by 53 percent as compared to 2004 levels. The 216 congestion-event hours during 2005 represented a 239-hour reduction as compared to the 455 congestion-event hours in 2004. Congestion on Midwest ISO flowgates constituted 1.2 percent of total PJM congestion-event hours in 2005. The largest reduction in congestion-event hours among Midwest ISO flowgates was Crete-St Johns Tap. In 2005, Crete-St Johns Tap was constrained for 81 hours as compared to the 368 congestion-event hours experienced during 2004.

Congestion on interfaces increased 44 percent from 1,018 event hours in 2004 to 1,463 event hours during 2005. Interfaces typically include multiple transmission facilities and are used to represent the flow into or through a wider geographic area. Interface congestion constituted 8 percent of total PJM congestion-event hours in 2005. Among interfaces, the 5004/5005 interface showed the greatest increase in congestion frequency with 567 event hours in 2005 as compared to 19 event hours during 2004. The 5004/5005 interface accounted for 39 percent of all interface congestion during 2005. During 2005, PJM more frequently used the 5004/5005 interface instead of the Central Interface when the limiting facility was the Juniata 500 kV bus. PJM determined that controlling the transmission system using the 5004/5005 interface constraint reduced the wide-area system impact of the Central Interface and resulted in generation shifts which were more consistent with relieving the voltage problems at Juniata.

Congestion on lines increased 121 percent from 4,622 event hours in 2004 to 10,230 event hours during 2005. Line congestion accounted for 58 percent of the total PJM congestion-event hours for 2005. The Bedington-Black Oak 500 kV line and the Laurel-Woodstown 69 kV line together accounted for 2,193 congestion-event hours or 21 percent of all line congestion during 2005. These two facilities were the third and forth most congested facilities, respectively, in PJM during 2005. Also significant was the Mount Storm-Pruntytown 500 kV line with 696 congestion-event hours during 2005.

Congestion on transformers increased 116 percent from 2,598 event hours in 2004 to 5,615 event hours during 2005. Congestion on transformers accounted for 32 percent of the total PJM congestion-event hours for 2005. The Wylie Ridge and Kammer transformers together accounted for 2,731 congestion-event hours or 49 percent of all transformer congestion-event hours during 2005. The Wylie Ridge and Kammer transformers were the two most frequently congested facilities in PJM during 2005. Allegheny Power reduced the ratings of both the Kammer and Wylie Ridge transformers during 2005, contributing to the increase in congestion frequency on these facilities.

The 412 hours of congestion experienced on the Branchburg transformers was down from the 1,005 hours experienced during 2004 and constituted the greatest decrease in congestion frequency of any facility in PJM compared to 2004. On March 17, 2004, PSEG significantly reduced the emergency and normal ratings of the Branchburg number 1 and number 2 transformers because of a deteriorating condition identified during an inspection. On May 25, 2004, a special protection scheme (SPS) was implemented at Branchburg to reduce the impact on congestion from the derated facilities. A third transformer was installed at Branchburg on April 25, 2005, to relieve this constraint.

Figure 7-3 provides congestion-event hour subtotals comparing calendar year results by facility type: line, transformer, interface and flowgate.

Figure 7-3 - Congestion-event hours (By facility type): Calendar years 2002 to 2005

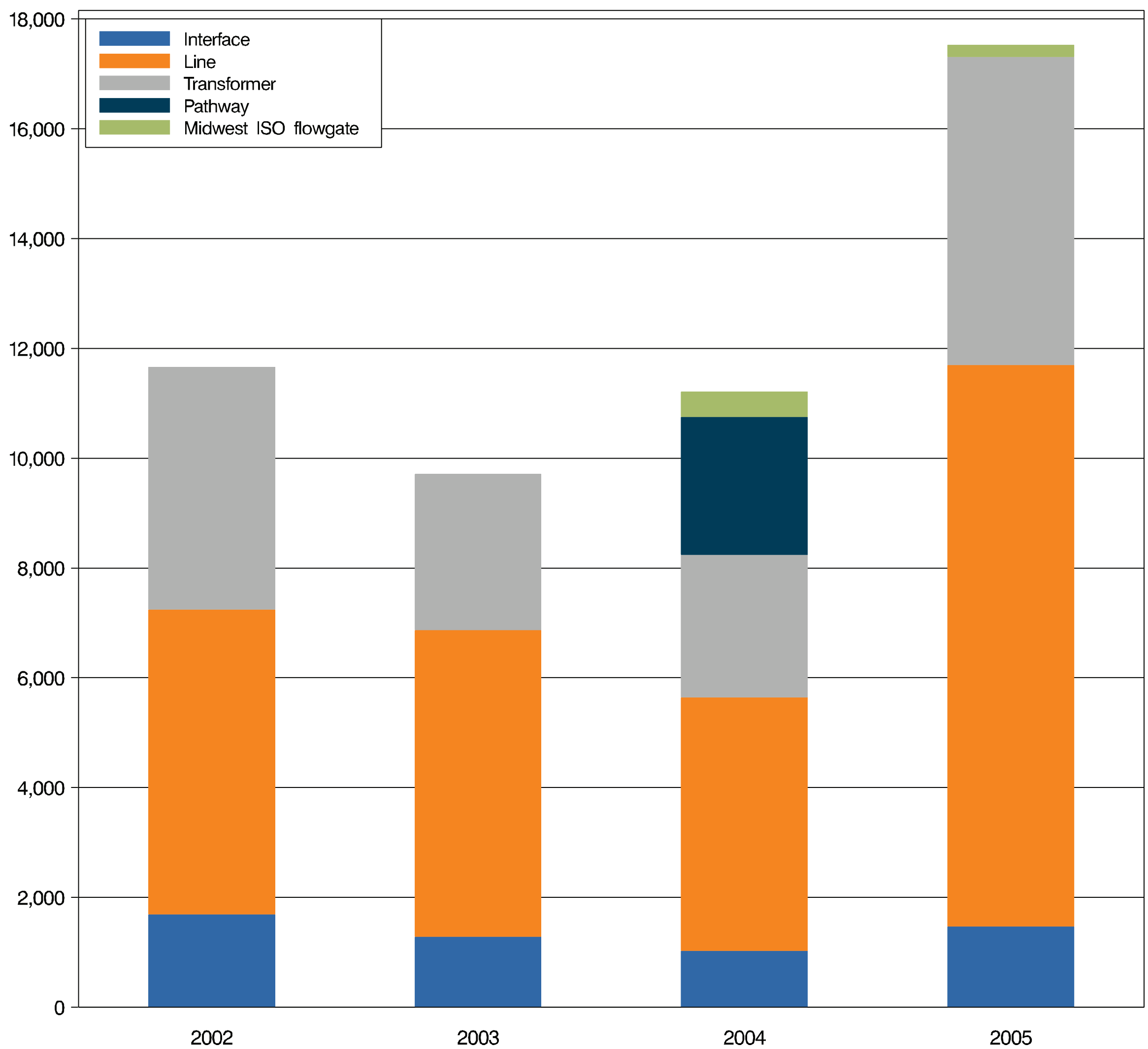
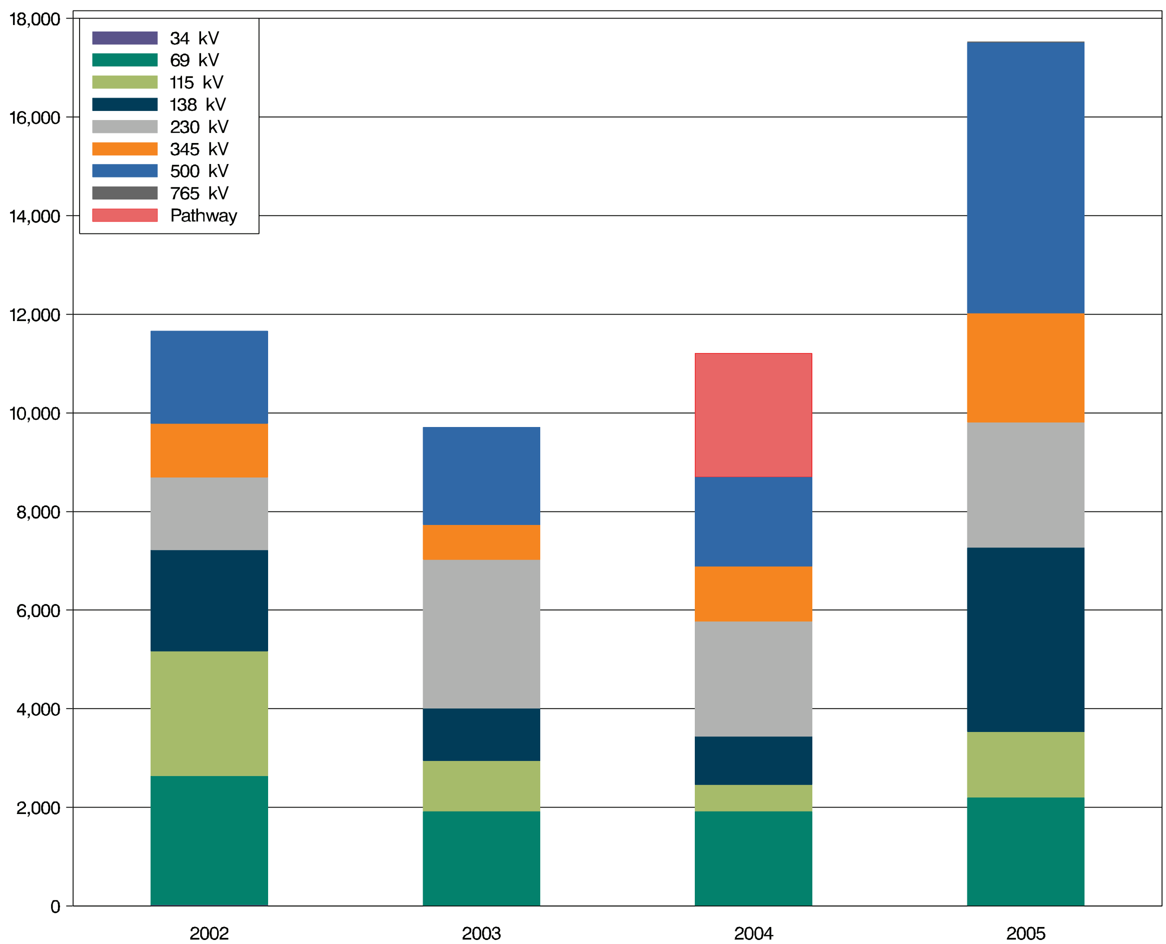


Figure 7-4 depicts congestion-event hour subtotals by facility voltage class. Congestion frequency increased across all voltage classes during 2005 as compared to 2004. The largest increase in congestion by voltage class was on 138 kV facilities. Congestion on 138 kV facilities increased by 283 percent with 3,741 event hours in 2005 as compared to the 977 event hours experienced during 2004. The largest contributions to congestion on 138 kV facilities came from the Charleroi-Mitchell line in the AP Control Zone and the Mahans Lane-Tidd line in the AEP Control Zone. These two facilities together experienced 766 congestion-event hours in 2005 constituting 20 percent of all congestion on 138 kV facilities and 4 percent of total PJM congestion-event hours.

Congestion on 500 kV facilities increased 204 percent with 5,494 congestion-event hours in 2005 as compared to the 1,809 congestion-event hours experienced during 2004. The largest contributors to 500 kV congestion were the Kammer transformer and the Bedington-Black Oak line. Together these facilities experienced 2,646 congestion-event hours or 48 percent of total 500 kV facility congestion during 2005. These facilities were also the second and third most frequently congested facilities, respectively, in PJM during 2005.

Congestion on 230 kV facilities increased by 8 percent with 2,537 congestion-event hours in 2005 as compared to the 2,340 congestion-event hours experienced during 2004. The largest contributor to 230 kV congestion was the Branchburg transformers located in the PSEG Control Zone. With 412 congestion-event hours, the Branchburg transformers constituted 16 percent of total 230 kV facility congestion. The Branchburg transformers also showed the greatest decrease in congestion frequency as compared to 2004 of any PJM facility. During 2004, the Branchburg transformers were the third most frequently constrained facility in PJM with 1,005 congestion-event hours. Both the Branchburg number 1 and number 2 500/230 kV transformers had previously experienced enough unhedgeable congestion to trigger the opening of a market window. The market windows for each of these facilities closed on May 18, 2005, with both transformers scheduled to be replaced by June 2007.

Figure 7-4 - Congestion-event hours (By facility voltage): Calendar years 2002 to 2005



Constraint Duration

Table 7-6 lists calendar year 2004 and 2005 constraints that affected more than 10 percent of PJM load or that were most frequently in effect and shows changes in congestion-event hours during both years.[16]

Constraints 1 through 8 are the primary operating interfaces. For this group, the number of congestion-event hours increased from 2,235 to 4,416 hours between 2004 and 2005, a 98 percent increase. The AP Control Zone facilities, items number 1, 2, 3 and 7, were constrained 4,062 hours in 2005, a 117 percent increase in frequency compared to 2004. This increase was driven by increased congestion frequency on the Kammer and Wylie Ridge transformers. Allegheny Power reduced the ratings of both the Kammer and Wylie Ridge transformers during 2005 contributing to the increase in congestion frequency on these facilities. The PJM Mid-Atlantic Region facilities, items number 4, 5, 6 and 8, were constrained 354 hours, a 3 percent decrease versus 2004.

Table 7-6 - Congestion-event summary: Calendar years 2004 to 2005

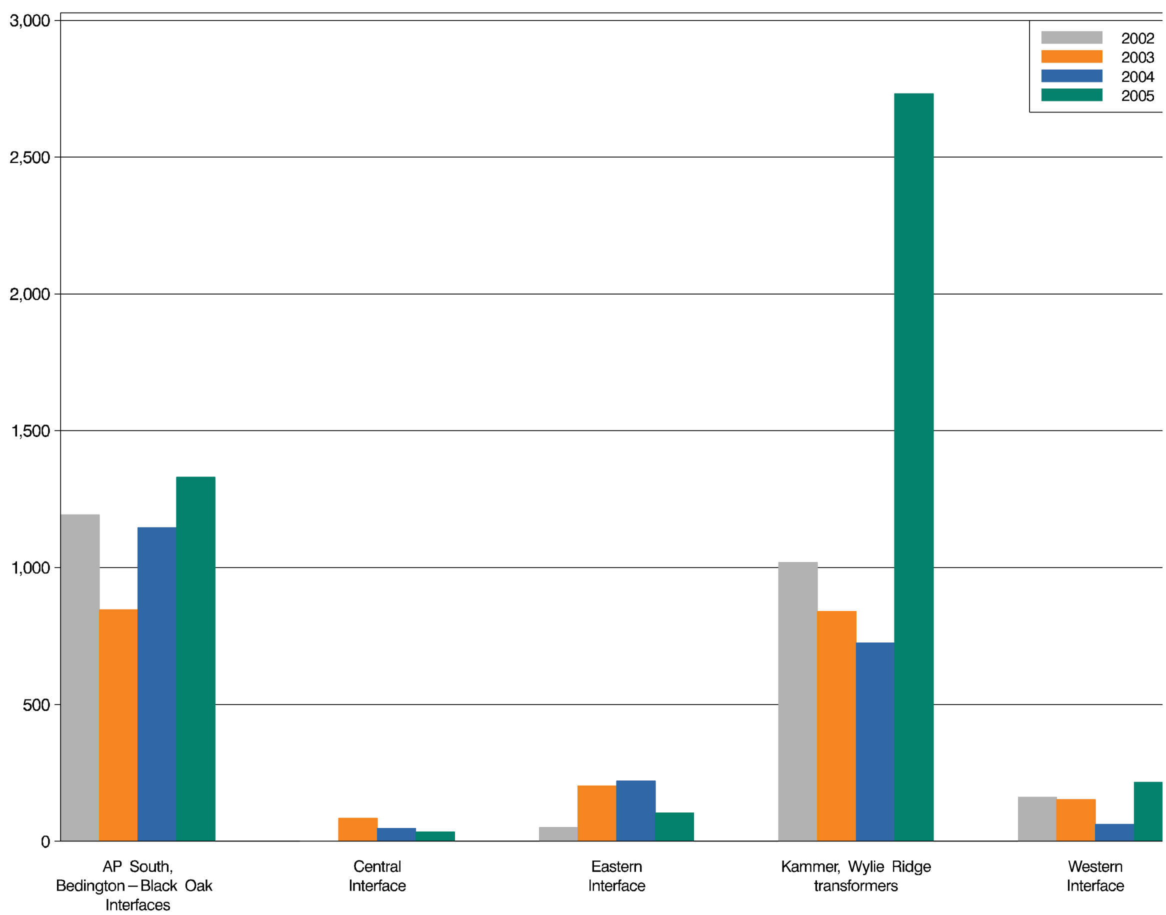
No.	Constraint	Congestion-Event Hours			Percent of Annual Hours		
		2004	2005	Change	2004	2005	Change
1	Wylie Ridge Transformer	642	1,399	757	7%	16%	9%
2	Kammer Transformer	84	1,332	1,248	1%	15%	14%
3	Bedington - Black Oak	1,131	1,314	183	13%	15%	2%
4	Western Interface	63	216	153	1%	2%	2%
5	Eastern Interface	221	103	(118)	3%	1%	(1%)
6	Central Interface	48	35	(13)	1%	0%	(0%)
7	AP South Interface	13	17	4	0%	0%	0%
8	PJM West 500	33	0	(33)	0%	0%	(0%)
9	Laurel - Woodstown	401	879	478	5%	10%	5%
10	Mount Storm - Pruntytown	0	696	696	0%	8%	8%
11	5004/5005 Interface	19	567	548	0%	6%	6%
12	Cloverdale - Lexington	31	508	477	0%	6%	5%
13	Mahans Lane - Tidd	69	448	379	1%	5%	4%
14	Cedar	605	438	(167)	7%	5%	(2%)
15	Doubs - Mount Storm	87	422	335	1%	5%	4%
16	Branchburg	1,005	412	(593)	11%	5%	(7%)
17	Kanawha - Matt Funk	51	401	350	1%	5%	4%
18	Cedar Grove - Roseland	150	364	214	2%	4%	2%
19	Doubs	85	321	236	1%	4%	3%
20	Charleroi - Mitchell	10	318	308	0%	4%	4%
21	Absecon - Lewis	0	283	283	0%	3%	3%
22	Bair - Hill	27	225	198	0%	3%	2%
23	Mitchell - Shepler Hill	42	214	172	0%	2%	2%
24	Bedington - Nipetown	21	213	192	0%	2%	2%
25	Edison - Meadow Rd	33	191	158	0%	2%	2%

16 Constrained-hour data presented here use the convention that if congestion occurs for 20 minutes or more in an hour, the hour is congested.

Congestion-Event Hours by Facility

Constraints that affected regions during calendar years 2002 through 2005 are presented in Figure 7-5. The Bedington-Black Oak line and the Kammer and Wylie Ridge transformers were the most significant regional constraints, and together comprised 23 percent of total PJM congestion-event hours during 2005. Congestion on the Bedington-Black Oak line increased by 183 hours or 16 percent during 2005 as compared to 2004. The Kammer transformer was constrained for 1,332 hours during 2005 as compared to 84 hours during 2004. The Wylie Ridge transformers experienced 1,399 congestion-event hours during 2005 as compared to 642 congestion-event hours during 2004.

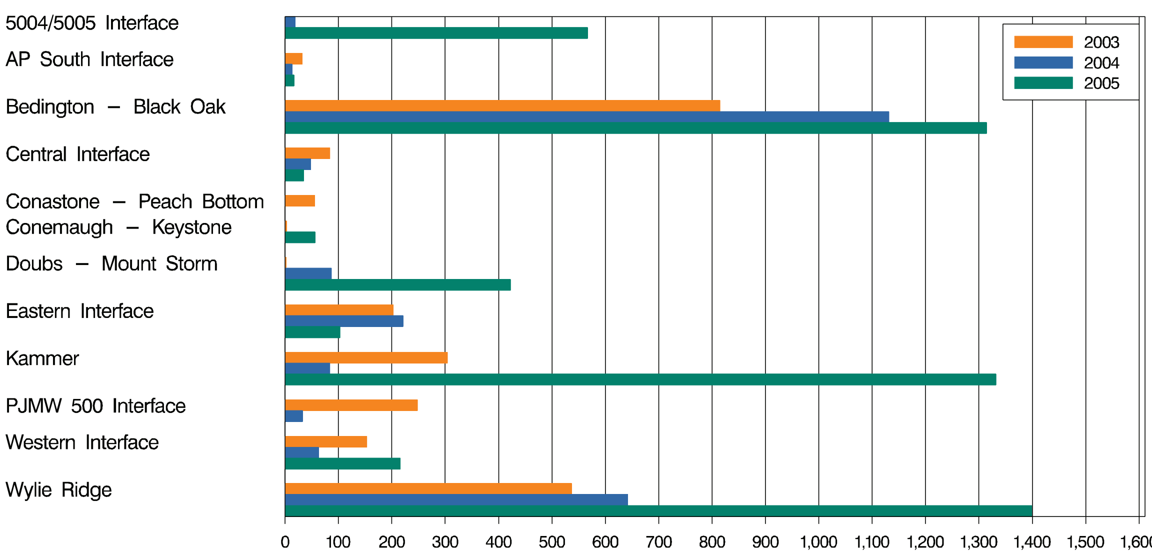
Figure 7-5 - Regional constraints and congestion-event hours (By facility): Calendar years 2002 to 2005



Congestion-Event Hours for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Figure 7-6 shows the occurrences of 500 kV constraints. Total 500 kV zone congestion increased by 13 percent from 4,928 congestion-event hours in 2004 to 5,548 congestion-event hours during 2005. The Wylie Ridge 500/345, Kammer 765/500, Bedington-Black Oak and 5004/5005 interface were constrained a combined total of 4,612 congestion-event hours in 2005 as compared to 1,876 hours in 2004, an increase of 2,736 hours or 146 percent. Allegheny Power reduced the ratings of both the Kammer and Wylie Ridge transformers during 2005 contributing to the increase in congestion frequency on these facilities. On August 11, 2005, Allegheny Power reduced the rating of the Wylie Ridge number 7 500/345 kV transformer by approximately 13 percent based on the results of a power transformer loadability study. Similarly, on June 30, 2005, Allegheny Power reduced the rating of the Kammer number 2 765/500 kV transformer between approximately 6 percent and 20 percent. The level of unhedgeable congestion on the Wylie Ridge transformer during 2004 led PJM to open a market window under the PJM economic planning process. The market window closed for Wylie Ridge number 5 500/345 kV transformer on April 1, 2005, and on the Wylie Ridge number 7 500/345 kV transformer on July 20, 2005. AP plans to upgrade the coolers on the existing Wylie Ridge 500/345 kV number 7 transformer prior to the summer of 2006 and will install a third 500/345 kV transformer at Wylie Ridge prior to June 2007. In the PJM Mid-Atlantic Region, the Western, Central and Eastern Interfaces were constrained a total of 354 hours, a 7 percent increase over the 332 hours experienced during 2004.

Figure 7-6 - 500 kV zone congestion-event hours (By facility): Calendar years 2003 to 2005



Congestion-Event Hours for 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. During 2005, Bedington-Black Oak and AP South were constrained 1,314 hours and 17 hours, respectively. During 2004, Bedington-Black Oak and AP South were constrained 1,131 hours and 13 hours, respectively. With

1,314 congestion-event hours, Bedington-Black Oak was the third most frequently constrained facility in PJM during calendar year 2005. Bedington-Black Oak experienced sufficient unhedgeable congestion during 2004 to trigger the opening of a market window under the PJM economic planning process. The market window for Bedington-Black Oak closed on March 4, 2005. Two solutions were proposed for the relief of congestion on Bedington-Black Oak. The first of these solutions addresses the reactive limitation and is comprised of a 525 MVar Static Var Compensator (SVC) to be installed at Black Oak prior to summer 2009. The second solution addresses the thermal limitation of the line and constitutes the replacement of a wave trap. The replacement of the wave trap was originally to be performed as a merchant transmission project (queue M05)[17] and had been designated as a market solution to the unhedgeable congestion. Allegheny Power subsequently replaced the wave trap in December of 2005. The MMU concluded that the AP Control Zone's South Interface constraint was competitive enough to be exempt from offer-capping procedures and recommended this modification in an August 26, 2004, filing to the United States Federal Energy Regulatory Commission (FERC).[18] Prior to the integration of the AP Control Zone into PJM on April 1, 2002, the primary controlling action for these constraints had been for AP to restrict energy transfers through its system, including transfers from western resources to PJM and Dominion Virginia Power. This action had the effect of raising the overall PJM dispatch rate higher than it would have been if the transactions had not been curtailed. The result was increased energy prices for the entire PJM Mid-Atlantic Region, regardless of location. There was no impact on measured congestion because the entire PJM system was affected.

Zonal Congestion

Constraints within specific zones from calendar years 2002 through 2005 are presented in Figure 7-7 which compares the frequency of constraints that occurred in each zone and on the 500 kV system. In 2005, the PSEG Control Zone had 1,761 congestion-event hours, a 7 percent decrease versus 2004.[19] A significant contribution to the decrease in constrained operation on the PSEG system was the installation of a third 500/230 kV transformer at Branchburg which went into service on April 25, 2005. The Branchburg transformer was constrained 1,005 hours during 2004, but only 412 hours in 2005, though it remained the most frequently constrained facility in the PSEG Control Zone.

The AP Control Zone had the greatest overall increase in congestion frequency as compared to 2004. Congestion in the AP Control Zone increased by 746 percent with 2,877 congestion-event hours during 2005 as compared to 340 congestion-event hours during 2004. The most significant contributors to this increase were the Doubs transformers and the Mount Storm-Pruntytown line. Together, these two facilities were constrained for 1,222 hours constituting 42 percent of the total AP Control Zone congestion-event hours.

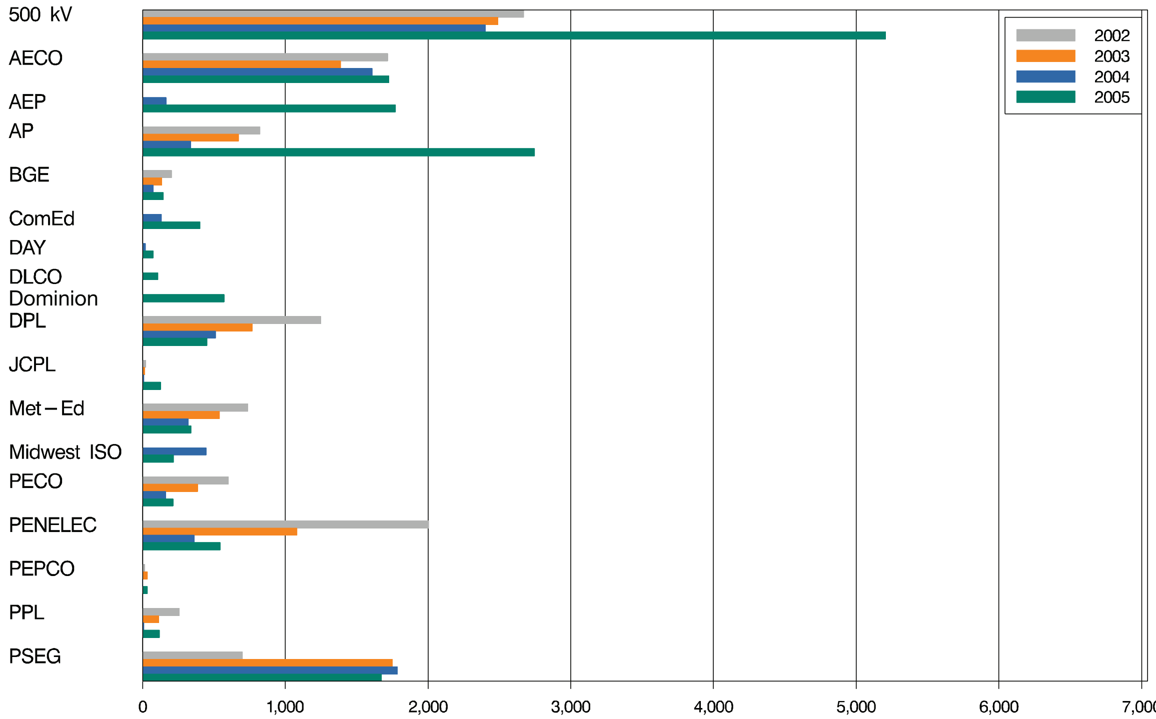
The AEP Control Zone experienced 1,901 congestion-event hours during 2005 constituting 11 percent of total PJM congestion-event hours for the year. During 2004, the AEP Control Zone was a part of PJM during the last three months of the year and experienced 168 congestion-event hours. The Mahans Lane-Tidd, Kanawha-Matt Funk and Cloverdale–Lexington lines saw increased congestion frequency as compared to 2004 and were the most frequently constrained facilities in the AEP Control Zone during 2005. These three facilities together had 1,357 congestion-event hours or 71 percent of all AEP Control Zone congestion.

17 See PJM, "#M05 Black Oak – Bedington 500 kV Wave Trap (Revised)" <http://www.pjm.com/planning/project-queues/merch-feas_docs/m05_fea.pdf > (117 KB).

18 *PJM Interconnection, L.L.C.*, Compliance Filing, Docket Nos. ER04-539-001, 002 and ER04-121-000 (October 26, 2004), Report of the PJM Market Monitor, P 17.

19 The value reported in the *2004 State of the Market Report*, 1,784 hours, was the number of constraint hours. The number of congestion-event hours during 2004 in the PSEG Control Zone was 1,895. As stated in the *2004 State of the Market Report*, PSEG had the highest number of congestion-event hours of any control zone during 2004.

Figure 7-7 - Constraint hours (By zone): Calendar years 2002 to 2005



Zonal and Subarea Congestion

Figure 7-8 through Figure 7-40 present constraints by control zones and subareas, and demonstrate the influence of individual constraints on zonal prices during calendar year 2005. Constraints can have wide-ranging effects, influencing prices across multiple zones. To illustrate this, the figures depict the congestion component of each zone's annual average LMP. The effects of each constraint during calendar year 2005 are expressed as a percent of the control zone's annual average LMP. The top constraints affecting zonal LMP are depicted in the congestion component graphs.

Mid-Atlantic Region Congestion-Event Hours and Congestion Components

AECO Control Zone

Figure 7-8 shows AECO Control Zone constraints. In particular, the very small Cedar subarea, consisting of just two 69 kV substations, Motts Farm and Cedar, continued to be frequently constrained and accumulated enough unhedgeable congestion to trigger the opening of a market window under the PJM economic planning process during 2004. Cedar subarea congestion comprised 26 percent of AECO Control Zone congestion-event hours during 2005. On June 29, 2005, the Cedar-Cardiff 230 kV line was placed into service and is expected to significantly reduce congestion in the Cedar subarea. During 2005, the Cedar interface was constrained for 438 hours between January and June, but experienced no congestion from July through December. Also significant was the Laurel-Woodstown 69 kV line in southern New Jersey (SNJ), which comprised 50 percent of the total congestion-event hours in the AECO Control Zone and 5 percent of total PJM congestion-event hours during 2005. The Laurel-Woodstown 69 kV line with 879 congestion-event hours was the fourth most frequently constrained facility in PJM during 2005. This facility had accumulated enough unhedgeable congestion to trigger the opening of a market window which closed on March 4, 2005, with Conectiv to completely rebuild the circuit by summer 2007. The Shieldalloy-Vineland 69 kV line, also located in SNJ, experienced 444 hours of congestion during 2004 and triggered the opening of a market window through the PJM economic planning process. In 2005, this facility was constrained for 82 hours. The market window for the Shieldalloy-Vineland 69 kV line closed on March 4, 2005, with Conectiv planning to upgrade its portion of the circuit by summer 2006. This action will not eliminate the congestion as customer-owned equipment will then become the limiting element. PJM is in discussions with the customer that owns the limiting facilities regarding potential remedies. The Absecon-Lewis 69 kV line had 283 congestion-event hours constituting 16 percent of AECO Control Zone congestion-event hours during 2005. This facility accumulated enough unhedgeable congestion to trigger the opening of a market window under the PJM economic planning process on November 8, 2005. This window is scheduled to close on November 8, 2006.

Figure 7-8 - AECO Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005

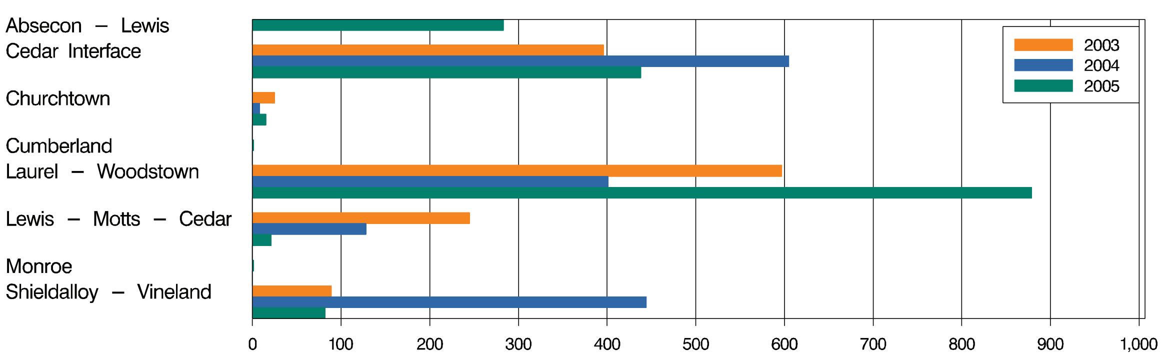
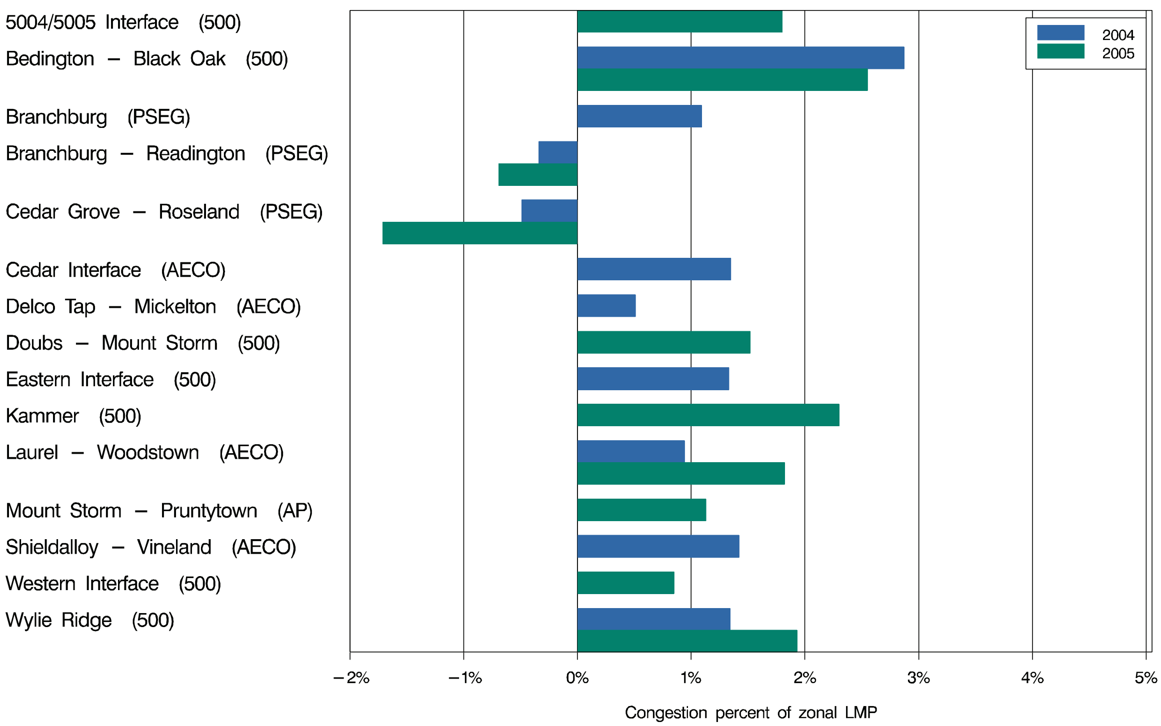


Figure 7-9 depicts the congestion components of AECO Control Zone LMP. The Bedington-Black Oak, Kammer transformer and Wylie Ridge transformer constraints caused the greatest increase in prices within the AECO Control Zone. The Cedar Grove-Roseland constraint caused the greatest decrease in prices in the AECO Control Zone.

Figure 7-9 - AECO Control Zone congestion components: Calendar years 2004 to 2005



BGE Control Zone

Figure 7-10 illustrates the BGE Control Zone constraints. With 151 congestion-event hours, the BGE Control Zone comprised 1 percent of the total PJM congestion-event hours in 2005. The Center-Westport 115 kV line was constrained 104 hours and was the only BGE Control Zone facility with greater than 100 congestion-event hours during 2005.

Figure 7-10 - BGE Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005

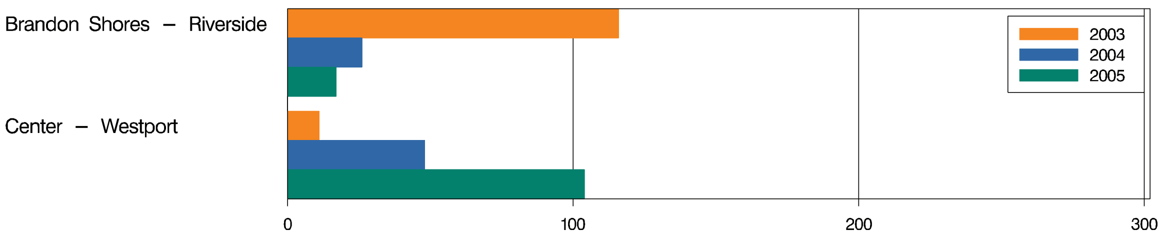
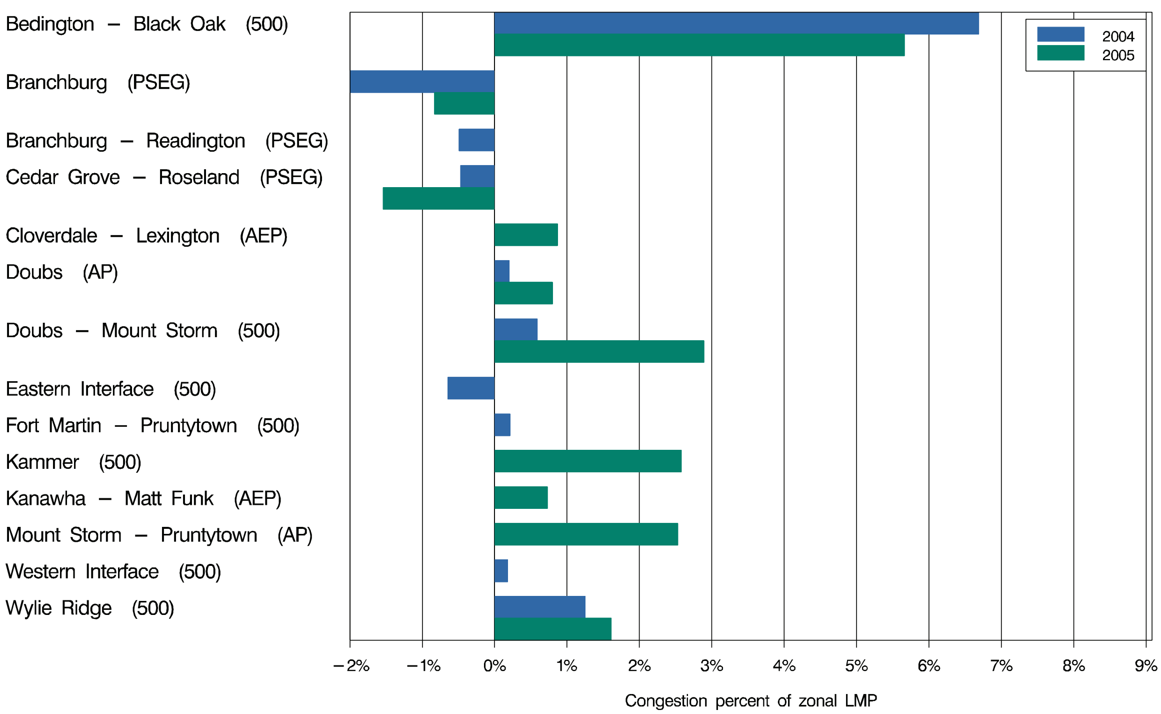


Figure 7-11 depicts the congestion components of the BGE Control Zone LMP. The Bedington-Black Oak constraint caused the greatest increase in prices while the Cedar Grove-Roseland constraint in PSEG caused the greatest decrease in prices in the BGE Control Zone.

Figure 7-11 - BGE Control Zone congestion components: Calendar years 2004 to 2005



DPL Control Zone

Figure 7-12 depicts DPL Control Zone constraint occurrences. During 2005, congestion-event hours in the DPL zone fell 14 percent from 2004 levels. DPL zone congestion-event hours represented 3 percent of total congestion-event hours in PJM. In 2005, no single facility in the DPL Control Zone was constrained more than 100 hours as compared to 2004 when two facilities exceeded this mark. The Keeney AT5N transformer was constrained 27 hours during 2005 as compared to 102 congestion-event hours during 2004. Improvements at Keeney are the result of disconnect upgrades at Keeney. These upgrades were performed on the AT-50 and AT-51 transformers and were completed in March and April 2004, respectively. The Keeney AT51 transformer incurred sufficient unhedgeable congestion during 2004 to open a market window under the PJM economic planning process. The market window closed on March 4, 2005, with the decision not to perform a proposed upgrade consisting of the installation of an additional 500/230 kV transformer at Red Lion. Based on PJM's analysis, the cost of this proposed upgrade would exceed the derived benefit by a 5-to-1 ratio. Issues with PJM's approach to cost-benefit analysis for transmission upgrades are discussed below.

Figure 7-12 - DPL Control Zone congestion-event hours (By subarea): Calendar years 2002 to 2005

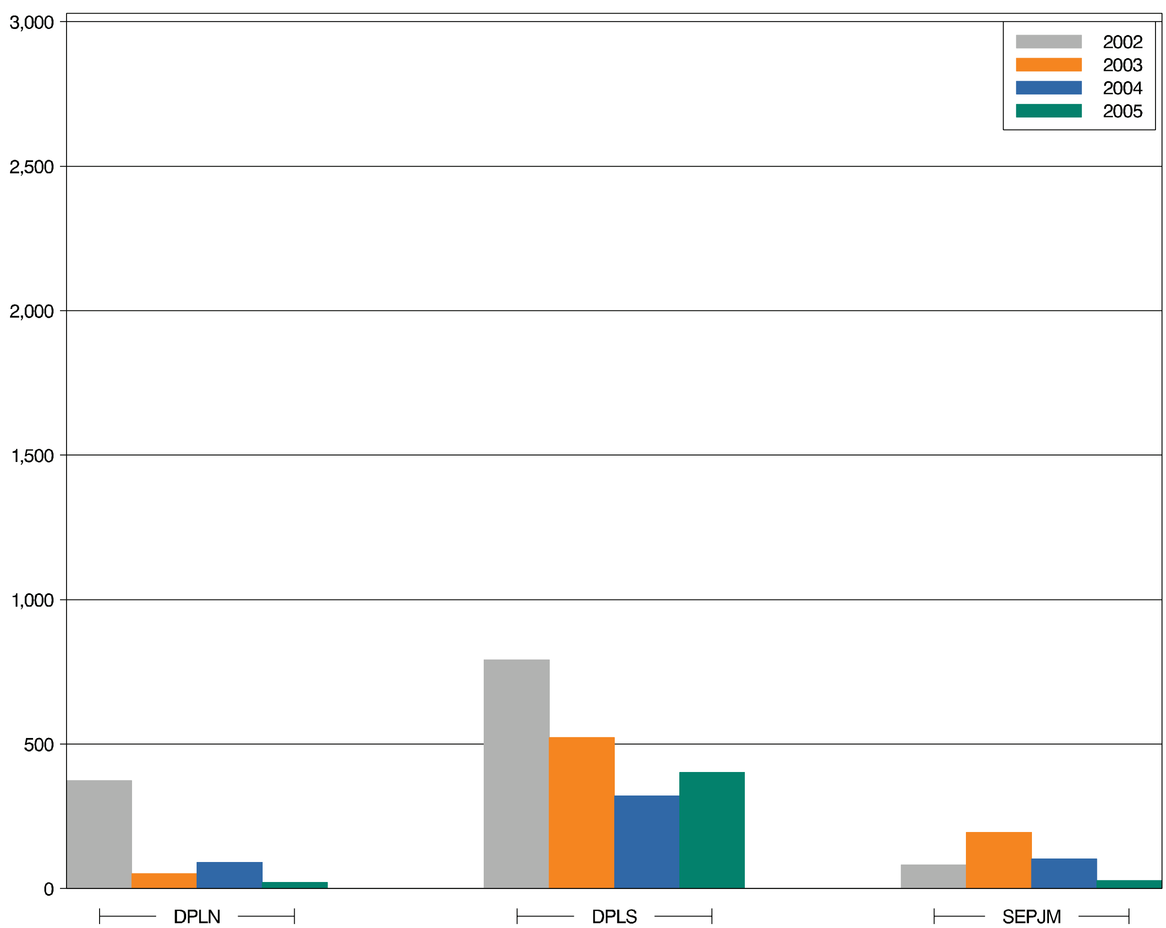


Figure 7-13 illustrates DPLS congestion-event hours by facility. Congestion in the DPLS subarea increased by 17 percent with 445 congestion-event hours in 2005 as compared to 381 congestion-event hours in 2004. No facility in DPLS was constrained more than 100 hours during 2005. Though it showed a 35 percent reduction in congestion frequency versus 2004, the Wye Mills AT2 69 kV transformer was constrained 83 hours and was the most frequently constrained facility in the DPL Control Zone in 2005. The Wye Mills AT2 transformer had previously incurred sufficient unhedgeable congestion to open a market window which closed on November 29, 2005. The transformer is to be replaced by the summer of 2006. The DuPont Seaford-Laurel 69 kV line, which had previously incurred sufficient unhedgeable congestion to open a market window under the PJM economic planning process, was constrained for 65 hours during 2005. The market window for this facility closed on March 4, 2005, with Conectiv to upgrade the circuit by the summer of 2006.

Figure 7-13 - DPLS subarea of the DPL Control Zone congestion-event hours (By facility): Calendar years 2002 to 2005

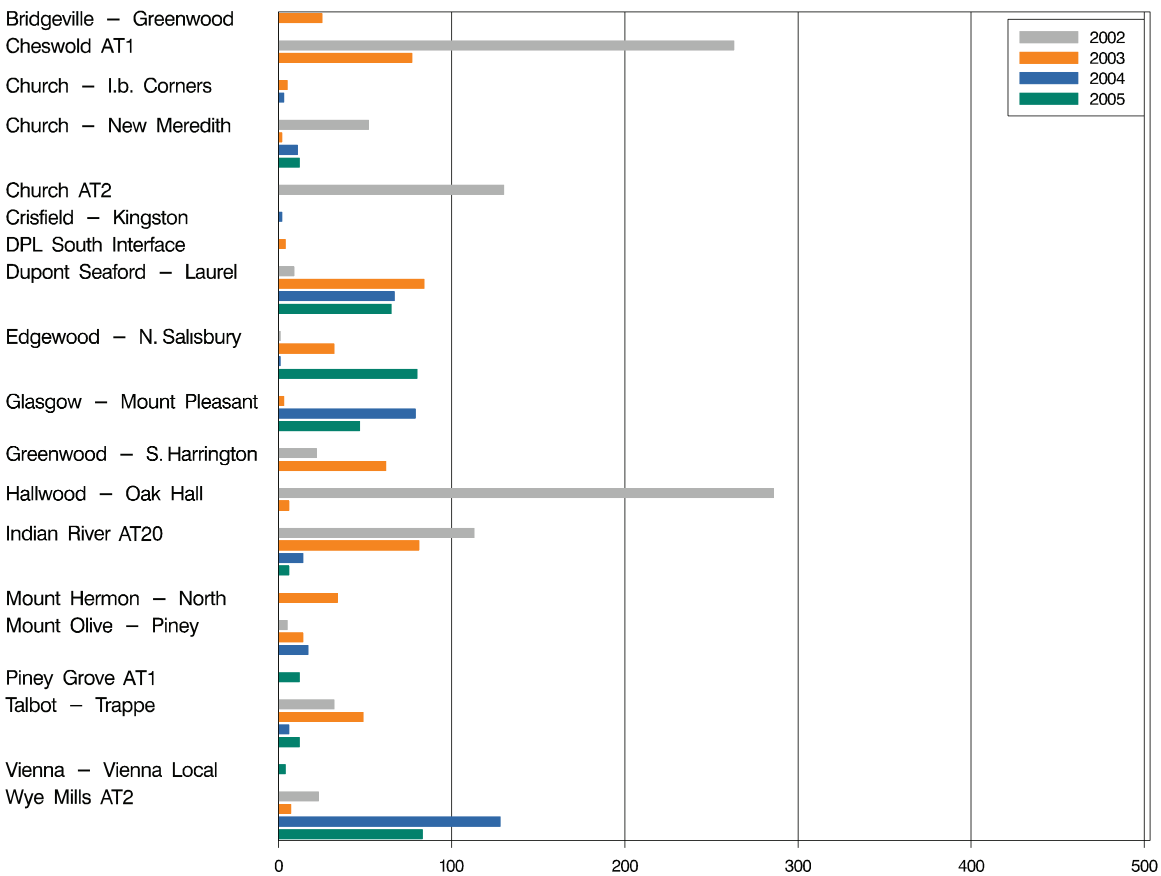
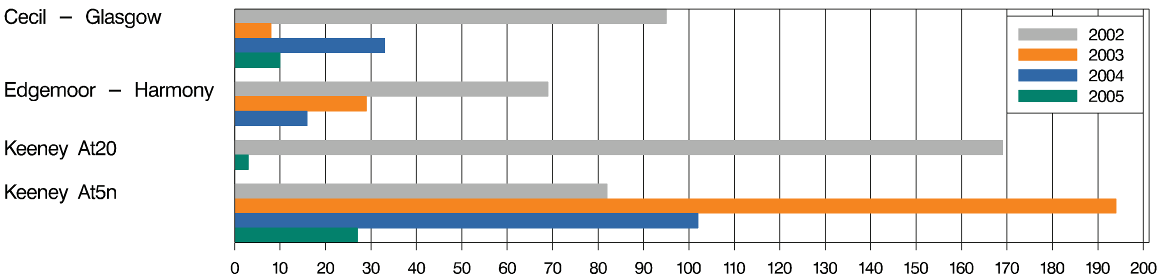


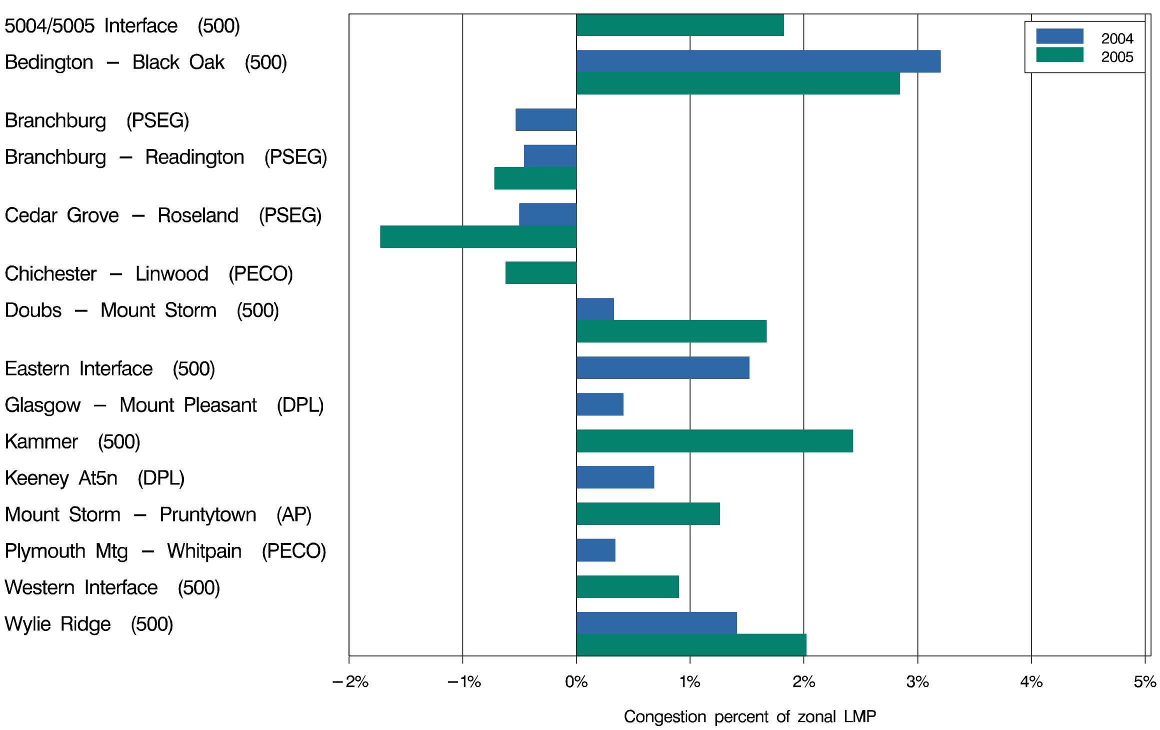
Figure 7-14 presents the same information for the DPLN and SEPJM subareas. The Keeney 500/230 kV transformer (Keeney AT5N), with 27 congestion-event hours, showed the largest decrease in frequency versus 2004 of any DPL Control Zone facility. No facilities were constrained more than 100 hours in DPLN or SEPJM in 2005.

Figure 7-14 - DPLN and SEPJM subareas of the DPL Control Zone congestion-event hours (By facility): Calendar years 2002 to 2005



As Figure 7-15 shows, the Bedington-Black Oak and Kammer transformer constraints caused the greatest increase in prices while the Cedar Grove-Roseland constraint caused the greatest decrease in prices in the DPL Control Zone.

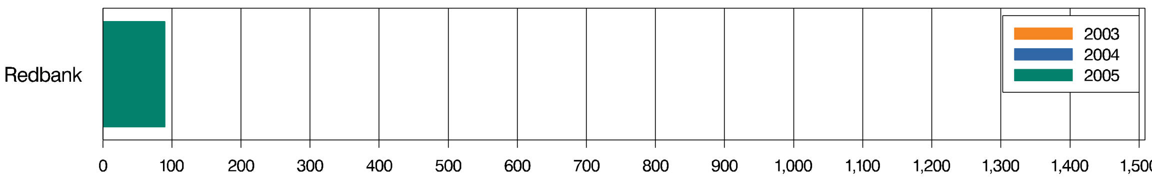
Figure 7-15 - DPL Control Zone congestion components: Calendar years 2004 to 2005



JCPL Control Zone

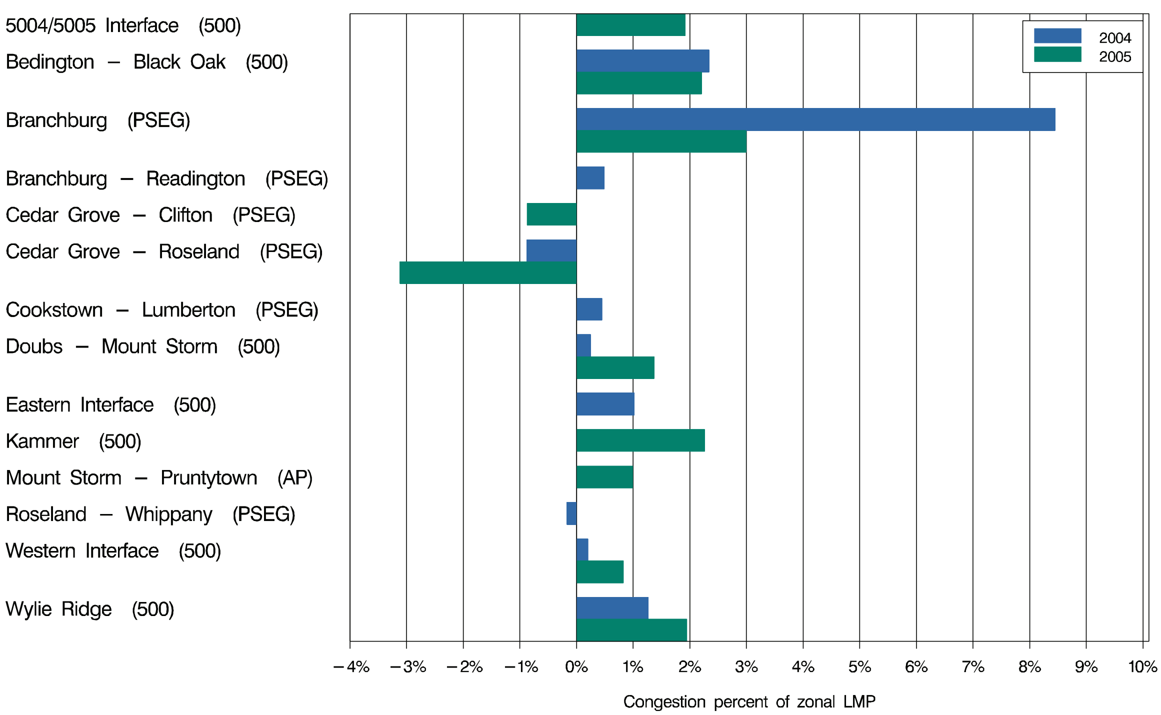
Figure 7-16 illustrates JCPL Control Zone constraints. The JCPL Control Zone has experienced little internal transmission congestion during the past two years. The JCPL Control Zone experienced nine congestion-event hours in 2004 and 125 congestion-event hours in 2005. Only one facility in the JCPL Control Zone was constrained more than 50 hours, the Redbank transformer with 90 congestion-event hours in 2005.

Figure 7-16 - JCPL Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005



As Figure 7-17 shows, the Branchburg transformer Bedington-Black Oak and Kammer transformer constraints caused the greatest increase in prices while Cedar Grove-Roseland caused the greatest decrease in prices in the JCPL Control Zone.

Figure 7-17 - JCPL Control Zone congestion components: Calendar years 2004 to 2005



Met-Ed Control Zone

Figure 7-18 illustrates Met-Ed Control Zone constraints. Congestion in Met-Ed increased by 53 hours from 2004 levels, a 15 percent increase. The Met-Ed west subarea (MEW) congestion increased, constituting 93 percent of total Met-Ed congestion-event hours in 2005 as compared to 83 percent during 2004. The increase in congestion-event hours in the Met-Ed west subarea was attributable to an increase in congestion on the Bair-Hill 115 kV line which was the most constrained facility in the Met-Ed Control Zone during 2005. The 225 congestion-event hours on Bair-Hill constituted an eight-fold increase over the 27 hours of congestion on this facility in 2004. This facility incurred sufficient unhedgeable congestion to open a market window under the PJM economic planning process on November 8, 2005. This window is scheduled to close on November 8, 2006. The Jackson 230/115 kV transformer, another Met-Ed west subarea facility, had the greatest decrease in congestion of any Met-Ed Control Zone facility versus 2004. The Jackson transformer had been the most constrained facility in Met-Ed during 2004 with 231 congestion-event hours, but experienced only 46 hours of congestion during 2005. Both the Jackson and Yorkana A 230/115 kV transformers had previously experienced enough unhedgeable congestion to trigger the opening of a market window. The market windows for each of these facilities closed on March 4, 2005, with their ratings being increased prior to the summer of 2005. These rating increases were responsible for the significant decrease in congestion during 2005 as compared to previous years. In addition, FirstEnergy is scheduled to install a third transformer at Jackson prior to June of 2006.

Figure 7-18 - Met-Ed Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005

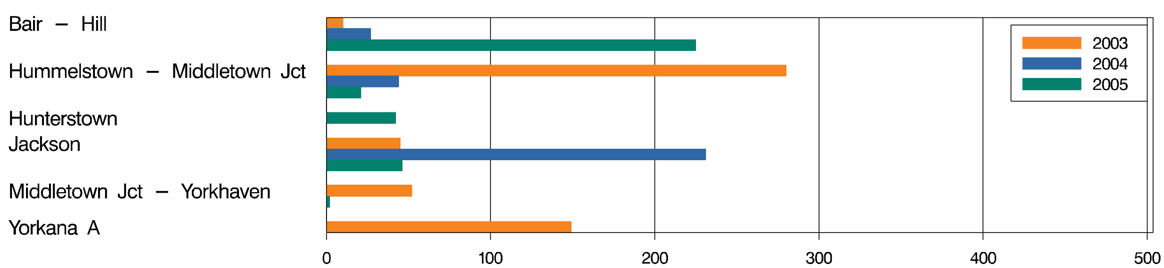
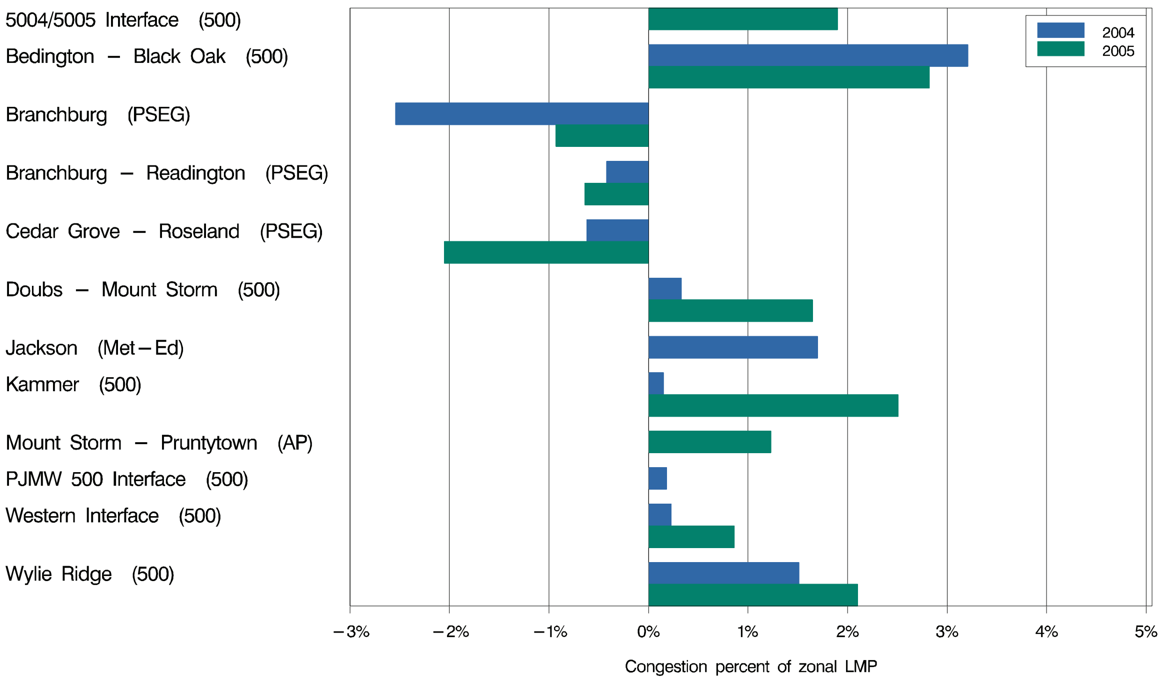


Figure 7-19 shows the congestion components of the Met-Ed Control Zone LMP. The Bedington-Black Oak, Kammer transformer and Wylie Ridge transformer constraints caused the greatest increase in prices while the Branchburg transformer and Cedar Grove-Roseland constraints caused the greatest decrease in prices in the Met-Ed Control Zone.

Figure 7-19 - Met-Ed Control Zone congestion components: Calendar years 2004 to 2005



PECO Control Zone

Figure 7-20 illustrates constraints in the PECO Control Zone where in 2005 only one facility was constrained more than 100 hours. The Chichester-Linwood 230 kV line with 128 congestion-event hours in 2005 was the most frequently constrained facility in the PECO Control Zone. The Whitpain 500/230 kV transformer was constrained for 59 hours during 2005, making it the second most constrained facility in the PECO Control Zone. There was a forced outage of the Whitpain number 2 500/230 kV transformer from July 2, 2005, through July 13, 2005.

The Whitpain 500/230 kV number 3 transformer accumulated enough unhedgeable congestion to trigger the opening of a market window under the PJM economic planning process on December 20, 2005. This window is scheduled to close on December 20, 2006.

Figure 7-20 - PECO Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005

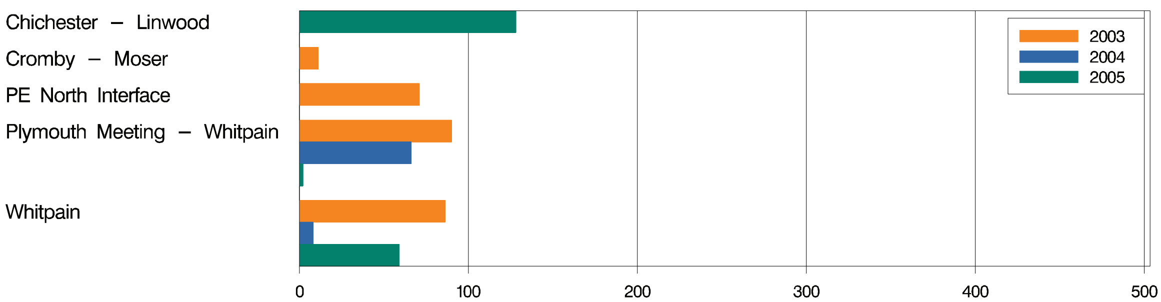
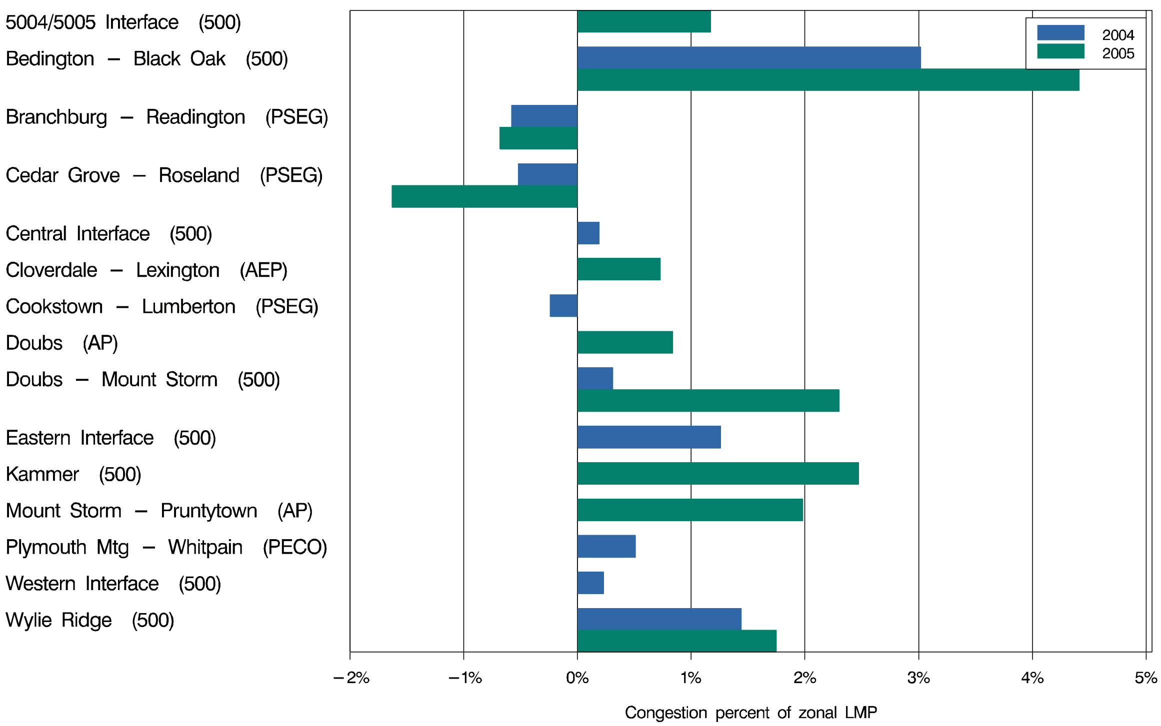


Figure 7-21 shows the congestion components of the PECO Control Zone LMP. The Bedington-Black Oak, Doubs-Mount Storm and Kammer transformer constraints caused the greatest increase in prices while the Cedar Grove-Roseland and Branchburg-Readington constraints in PSEG caused the greatest decrease in prices in the PECO Control Zone.

Figure 7-21 - PECO Control Zone congestion components: Calendar years 2004 to 2005



PENELEC Control Zone

Figure 7-22 illustrates PENELEC Control Zone constraints. Congestion-event hours in the PENELEC zone increased by 187 hours or 51 percent versus 2004, with most of the increase occurring in northwestern PENELEC. In 2004, the Erie West transformer experienced no congestion, a result of the installation of a second transformer at Erie West. With 142 congestion-event hours during 2005, the Erie West transformer was the most frequently constrained facility in PENELEC. Congestion on Erie West in 2005 occurred entirely during the month of May and was attributable to the concurrent outages of the Wayne 345/115 kV number 2 transformer and the Erie West #8 345 kV breaker. The Erie West #8 345 kV was out of service from April 18, 2005, through May 27, 2005. In total, the PENELEC Control Zone constituted 3 percent of total PJM congestion-event hours during 2005.

Figure 7-22 - PENELEC Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005

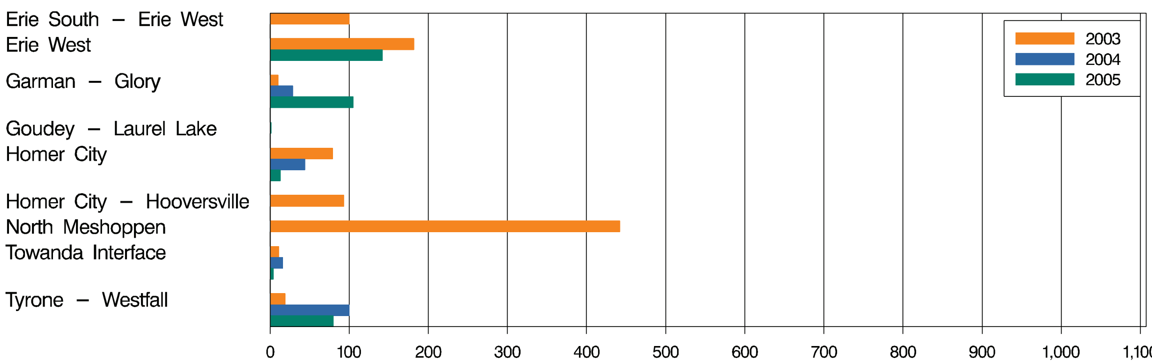
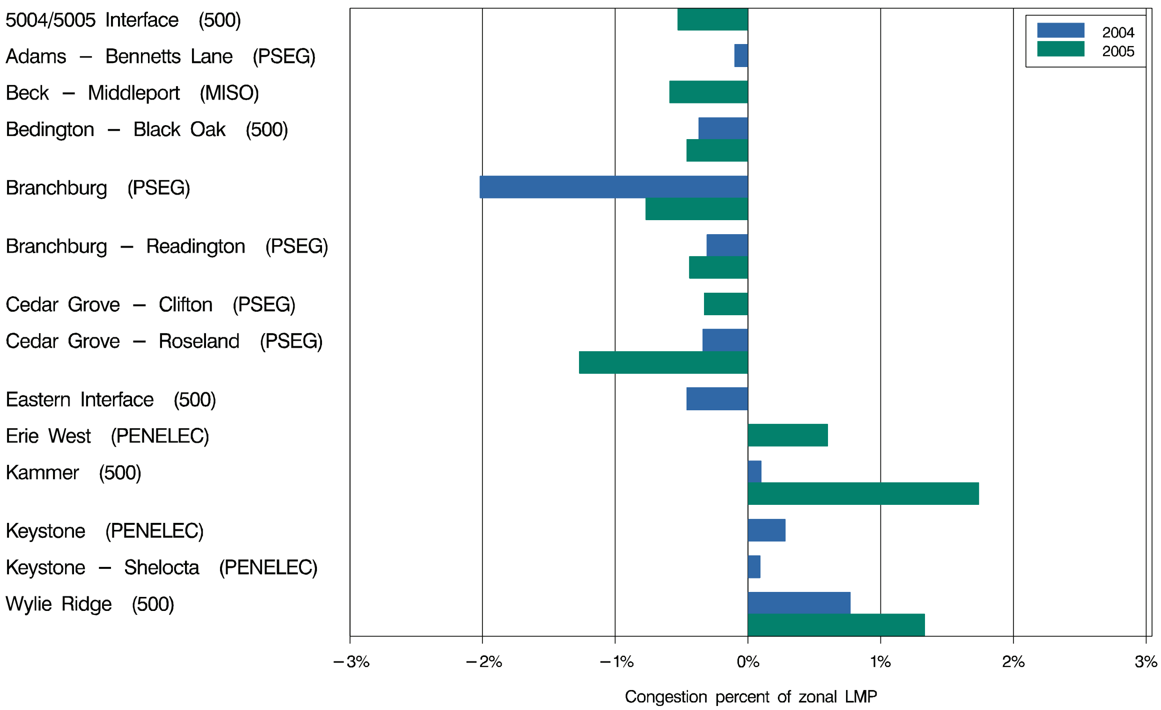


Figure 7-23 shows that the Kammer transformer constraint caused the greatest increase in prices while the Cedar Grove-Roseland constraint caused the greatest decrease in prices in the PENELEC Control Zone.

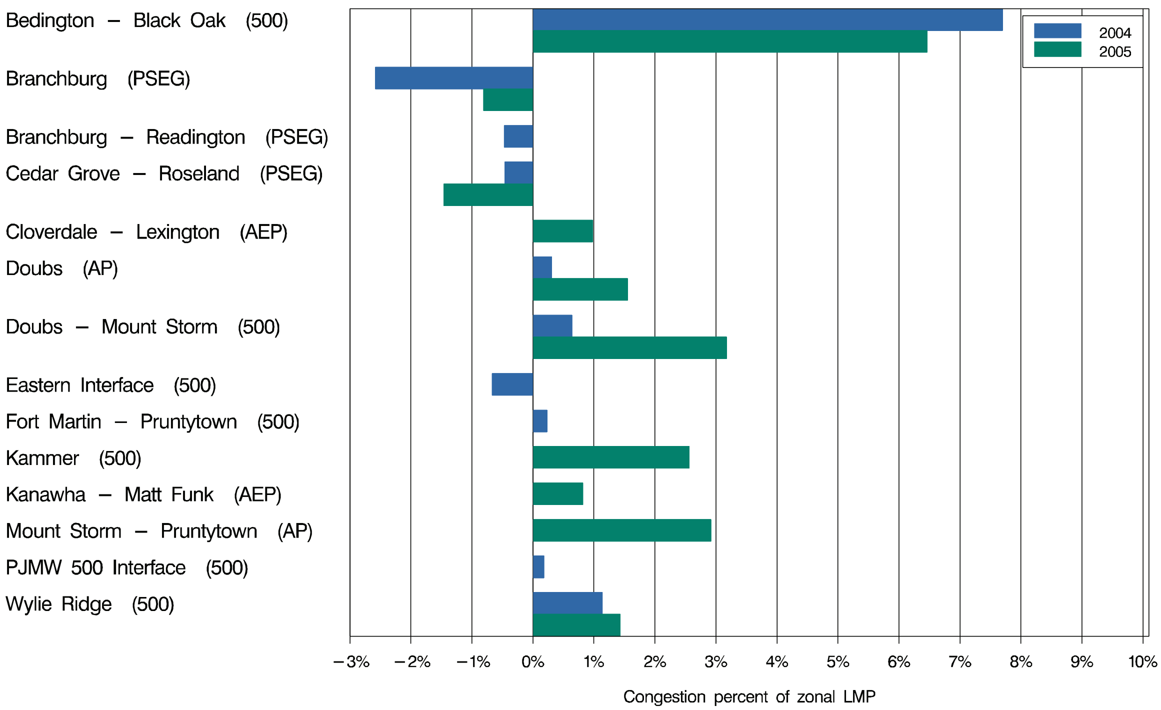
Figure 7-23 - PENELEC Control Zone congestion components: Calendar years 2004 to 2005



PEPCO Control Zone

The PEPCO Control Zone, for which no congestion frequency figure is shown, has experienced very few internal transmission constraints, with one congestion-event hour in 2004 and 32 congestion-event hours in 2005. While the PEPCO zone itself has experienced few internal constraints, PEPCO zonal prices are affected by congestion elsewhere on the system. As Figure 7-24 shows, the Bedington-Black Oak, Doubs-Mount Storm and Mount Storm-Pruntytown constraints caused the greatest increase in prices while the Cedar Grove-Roseland constraint caused the greatest decrease in prices in the PEPCO Control Zone.

Figure 7-24 - PEPCO Control Zone congestion components: Calendar years 2004 to 2005



PPL Control Zone

Figure 7-25 illustrates the frequency of PPL Control Zone constraints. During 2005, the PPL Control Zone experienced 118 congestion-event hours, an increase from the eight congestion-event hours experienced during 2004. The majority of the increase in congestion occurred on the PL North reactive interface. With 81 congestion-event hours, the PL North interface was the most frequently constrained facility in the PPL Control Zone during 2005.

Figure 7-25 - PPL Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005

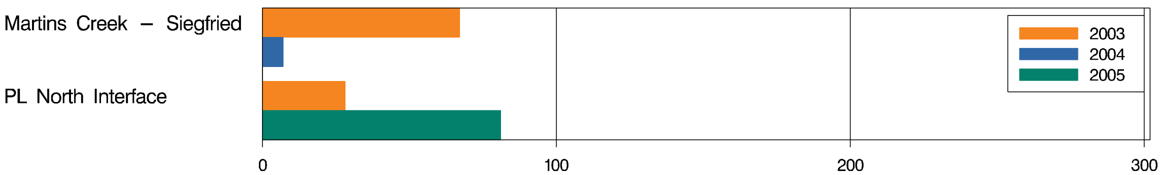
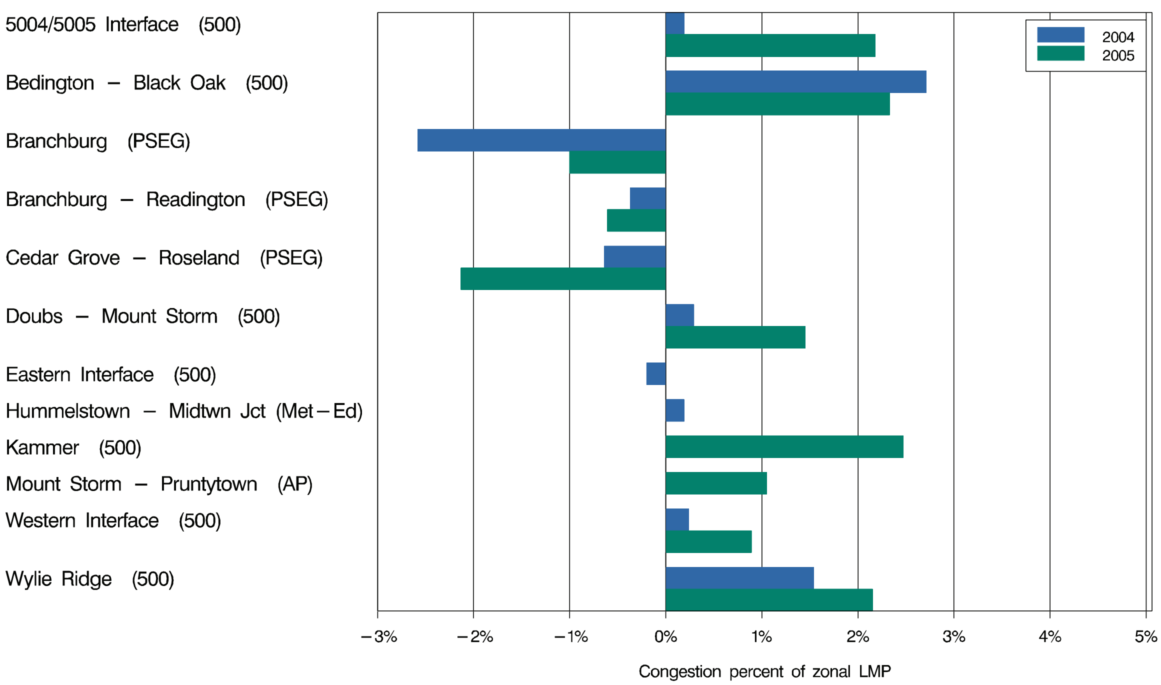


Figure 7-26 shows that the greatest increase in prices in the PPL Control Zone resulted from the Kammer transformer, Bedington-Black Oak, Wylie Ridge transformer and the 5004/5005 interface constraints. The Cedar Grove-Roseland and Branchburg transformer constraints caused the greatest decrease in prices in the PPL Control Zone.

Figure 7-26 - PPL Control Zone congestion components: Calendar years 2004 to 2005



PSEG Control Zone

Figure 7-27 illustrates constraint occurrences in the PSEG Control Zone. Total congestion frequency in PSEG was 7 percent lower with 1,761 congestion-event hours during 2005 versus 1,895 congestion-event hours in 2004. The 412 hours of congestion at Branchburg were down from the 1,005 hours experienced during 2004 and constituted the greatest decrease in congestion frequency of any facility in PJM as compared to 2004. On March 17, 2004, PSEG significantly reduced the emergency and normal ratings of the Branchburg number 1 and number 2 transformers because of a deteriorating condition identified during an inspection. On May 25, 2004, an SPS was implemented at Branchburg to reduce the impact on congestion from the derated facilities. A third transformer was installed at Branchburg on April 25, 2005, to relieve this constraint. Both the Branchburg number 1 and number 2 500/230 kV transformers had previously experienced enough unhedgeable congestion to trigger the opening of a market window. The market windows for each of these facilities closed on May 18, 2005, with both transformers scheduled to be replaced by June 2007. The Cedar Grove-Roseland 230 kV line had 364 congestion-event hours and was the second most frequently constrained facility in the PSEG Control Zone during 2005. Congestion on Cedar Grove-Roseland increased with the installation of a third transformer at Branchburg in April 2005. The rating reduction on the Branchburg transformers previously had the effect of limiting imports into the northern PSEG Control Zone and reduced the loading on this facility. During 2004, Cedar Grove-Roseland had been constrained for 150 hours. The Edison-Meadow Road 138 kV line was constrained for 191 hours in 2005 as compared to 33 hours during 2004. This line had previously incurred sufficient unhedgeable congestion to open a market window which closed on March 4, 2005. PSEG will be upgrading this circuit prior to the summer of 2009 which will increase the facility's rating by 60 percent.

Figure 7-27 - PSEG Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005

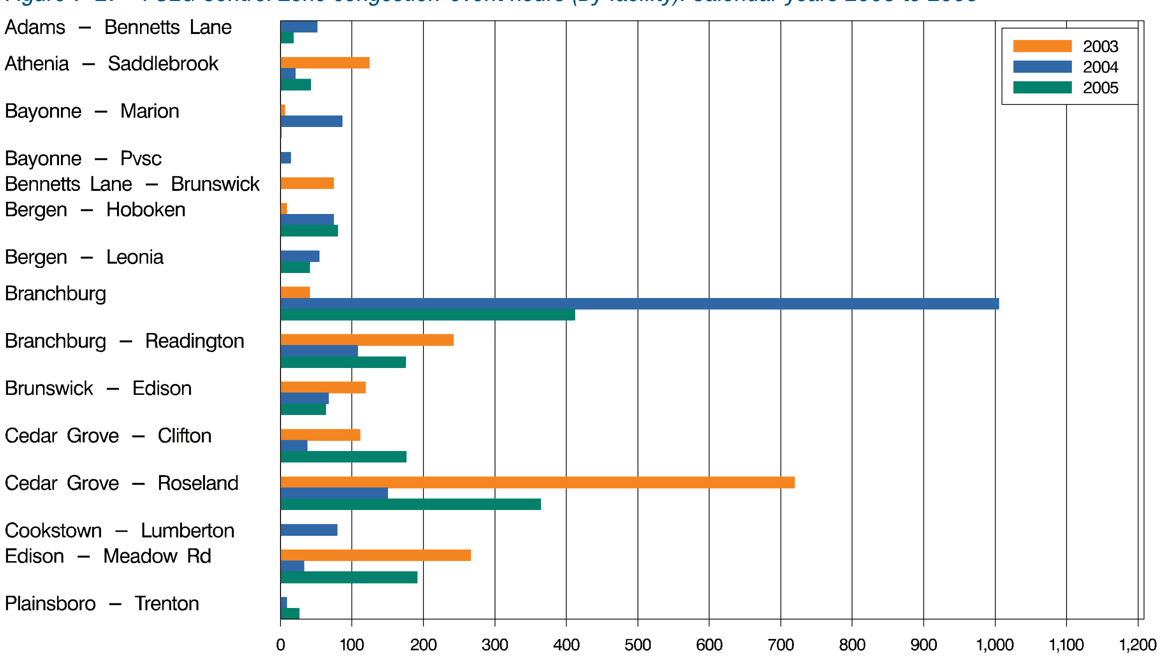
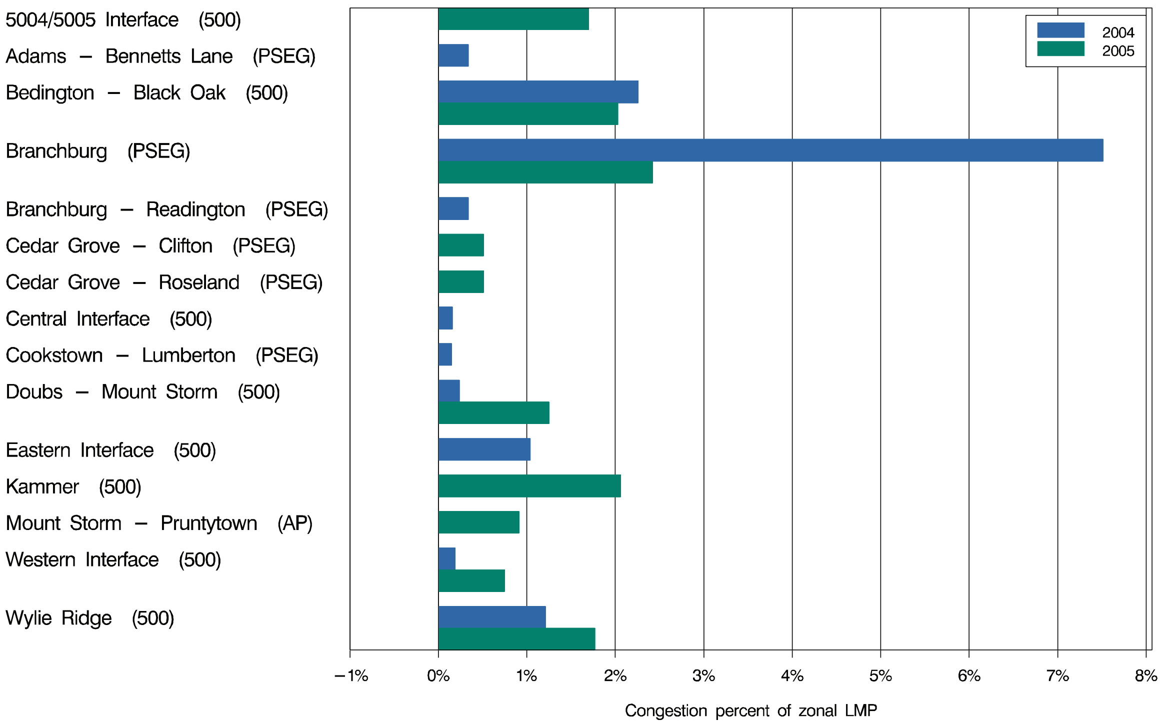


Figure 7-28 shows that the Branchburg transformer, a PSEG Control Zone facility, Bedington-Black Oak and Kammer transformer constraints increased prices in the PSEG Control Zone. There were no constraints that significantly reduced prices in the PSEG Control Zone during 2005.

Figure 7-28 - PSEG Control Zone congestion components: Calendar years 2004 to 2005



Western Region Congestion-Event Hours and Congestion Components

AEP Control Zone

Figure 7-29 illustrates constraint occurrences in the AEP Control Zone. There were 1,901 congestion-event hours in 2005 as compared to the 168 congestion-event hours experienced during the three months following its Phase 3 integration into PJM on October 1, 2004. The Cloverdale-Lexington 500 kV line with 508 congestion-event hours was the most frequently constrained AEP Control Zone facility in 2005. This facility accumulated sufficient unhedgeable congestion to open a market window under the PJM economic planning process on May 5, 2005. This market window is scheduled to close on May 5, 2006. The Mahans Lane-Tidd 138 kV line and the Kanawha-Matt Funk 345 kV line with 448 and 401 congestion-event hours, respectively, were the second and third most frequently constrained facilities in the AEP Control Zone during 2005. These two facilities together with the Cloverdale-Lexington line accounted for 71 percent of all AEP Control Zone congestion during 2005. Before the integration of AEP, congestion on these facilities had been managed through the use of North American Electric Reliability Council (NERC) TLRs. Since then, however, given PJM's reliance on LMP, the impacts of these constraints have become more localized.

Figure 7-29 - AEP Control Zone congestion-event hours (By facility): Phase 3, 2004 to December 31, 2005

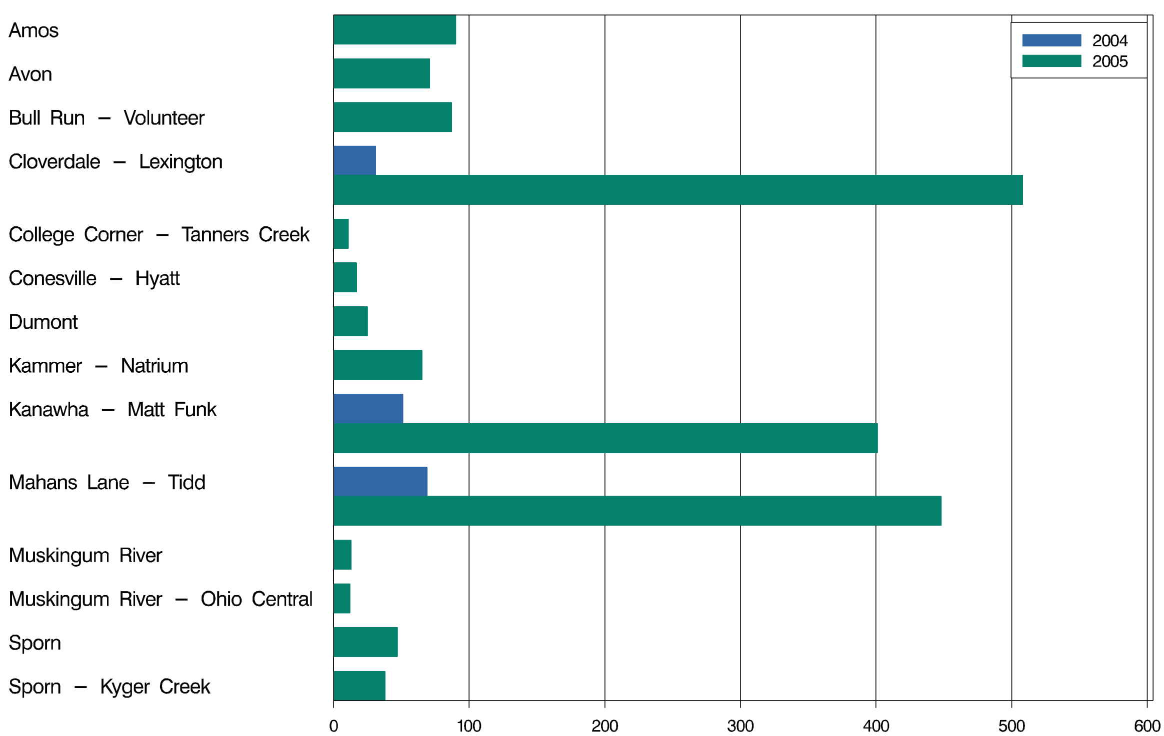
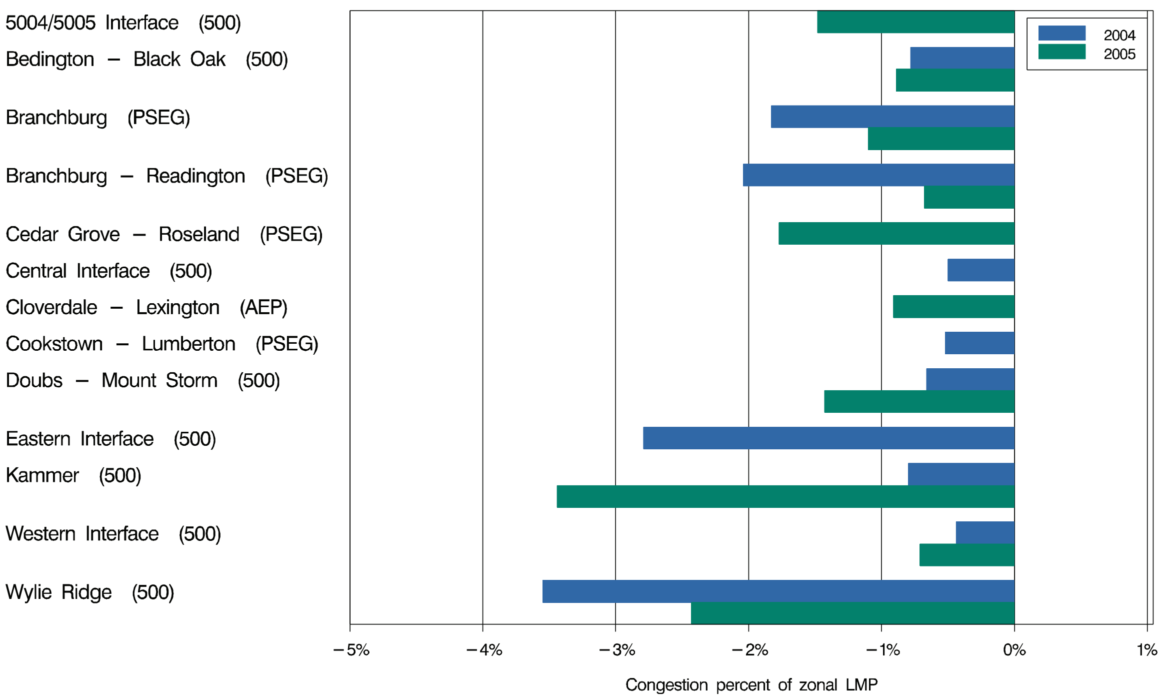


Figure 7-30 shows that the Kammer and Wylie Ridge transformer constraints caused the greatest reduction in prices in the AEP Control Zone. There were no constraints that significantly increased prices in the AEP Control Zone during 2005.

Figure 7-30 - AEP Control Zone congestion components: Phase 3, 2004 to December 31, 2005



AP Control Zone

Figure 7-31 illustrates the AP Control Zone constraints. Congestion in the AP Control Zone increased by 746 percent with 2,877 congestion-event hours during 2005 as compared to 340 congestion-event hours during 2004. Driving this change was an increase in congestion on the Doubs transformers which experienced 441 more congestion-event hours during 2005 than they had in 2004. There were 696 hours of congestion on the Mount Storm-Pruntytown 500 kV line which experienced no congestion during 2004. Together, these two facilities were constrained for 1,222 hours constituting 42 percent of the total AP Control Zone congestion-event hours. Congestion on Mount Storm – Pruntytown began to occur after the May 1, 2005, integration of Dominion. Prior to this, congestion had been managed through the use of TLRs.

Figure 7-31 - AP Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005

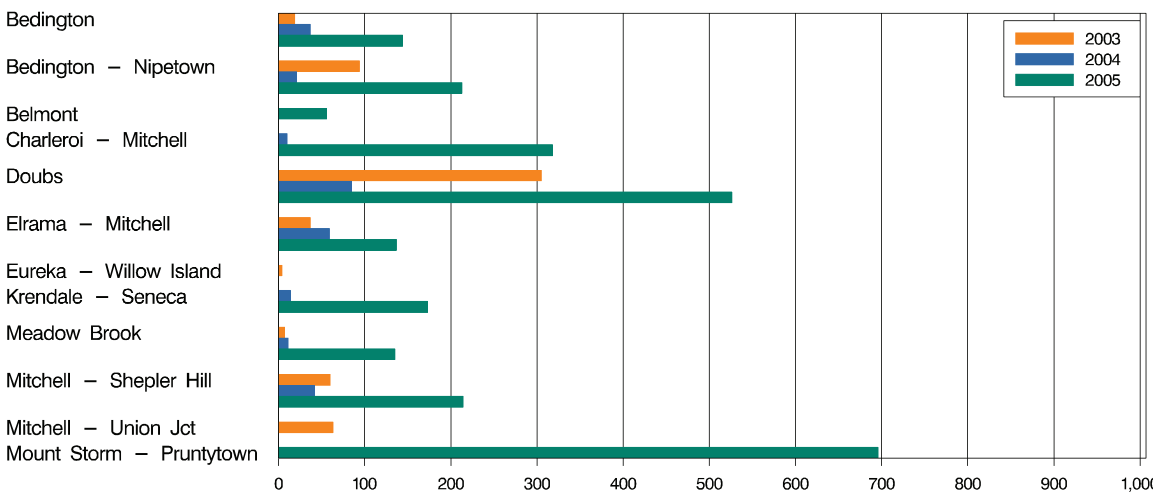
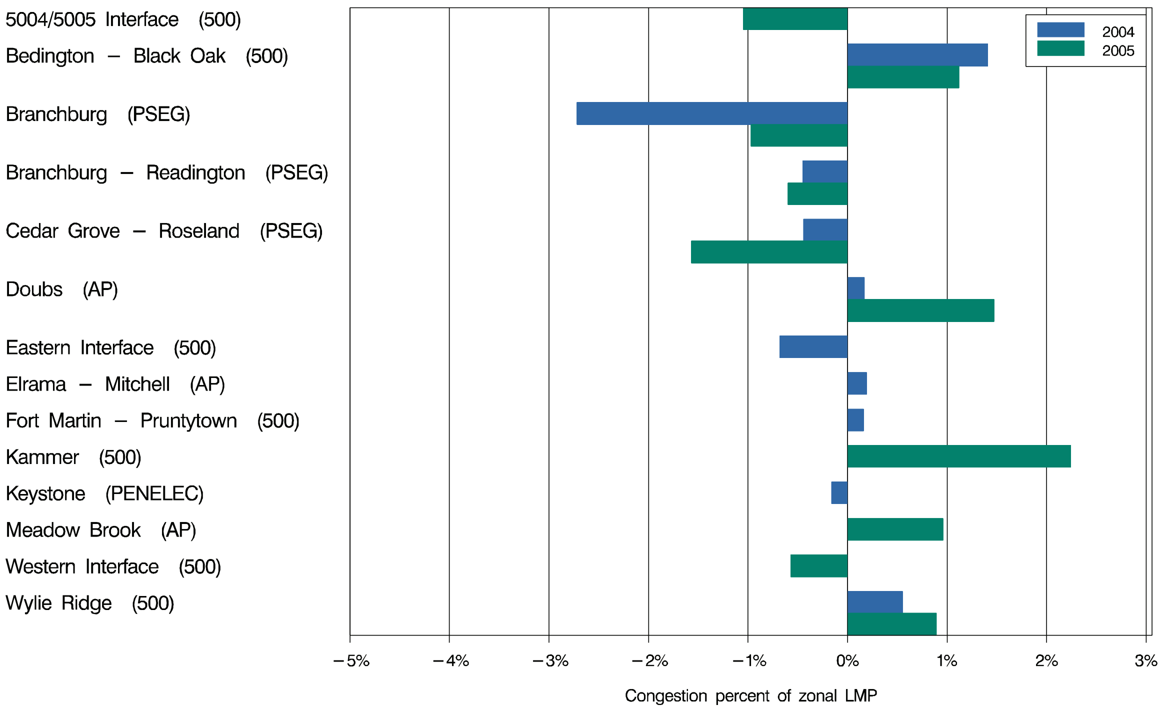


Figure 7-32 shows the congestion components of the AP Control Zone LMP. The Kammer transformer and Doubs transformer constraints caused the greatest increase in prices while the Cedar Grove-Roseland constraint in PSEG caused the greatest decrease in prices in the AP Control Zone.

Figure 7-32 - AP Control Zone congestion components: Calendar years 2004 to 2005



ComEd Control Zone

Figure 7-33 illustrates constraint occurrences in the ComEd Control Zone. There were 517 congestion-event hours in the ComEd Control Zone during 2005. During the eight months following its Phase 2 integration into PJM on May 1, 2004, the ComEd Control Zone experienced 130 congestion-event hours. There was one facility constrained more than 100 hours during 2005, the Cherry Valley 345/138 kV transformer which was constrained for 104 hours. The Waukegan-Round Lake 138 kV line with 79 congestion-event hours was the second most constrained facility in the ComEd Control Zone during 2005. Congestion in the ComEd zone was minimized by post-contingency switching procedures which are employed where PJM would have otherwise initiated out-of-merit dispatch.

Figure 7-33 - ComEd Control Zone congestion-event hours (By facility): Phase 2, 2004 to December 31, 2005

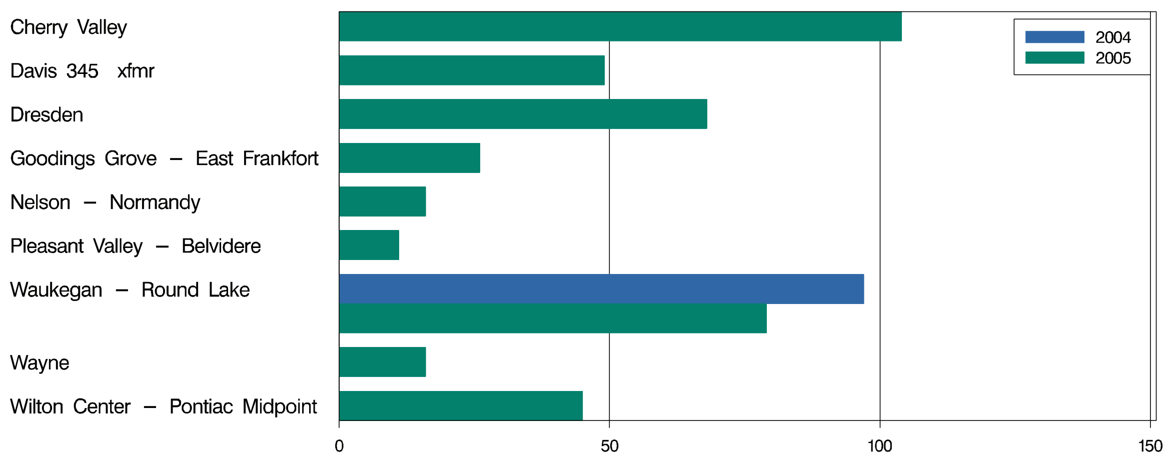
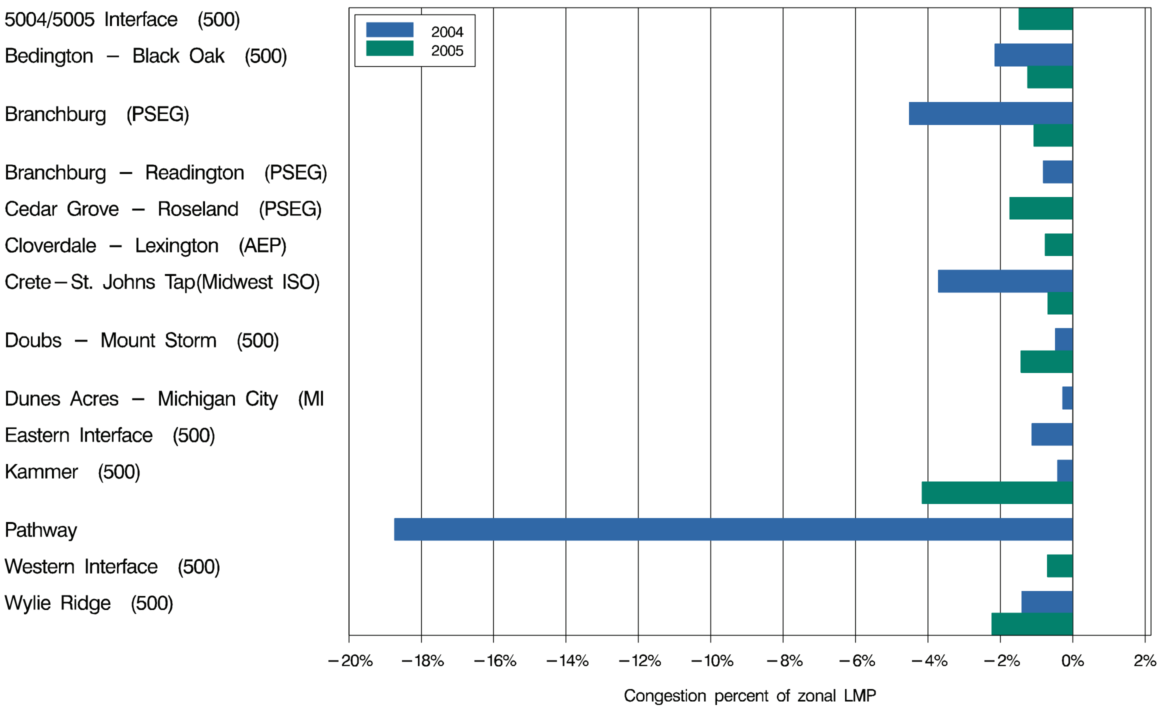


Figure 7-34 depicts congestion components of the ComEd Control Zone LMP during 2005. Constraints on the Kammer and Wylie Ridge transformers reduced prices in the ComEd Control Zone. There were no constraints that significantly increased prices in the ComEd Control Zone during 2005.

Figure 7-34 - ComEd Control Zone congestion components: Phase 2, 2004 to December 31, 2005



DAY Control Zone

Figure 7-35 illustrates constraint occurrences in the DAY Control Zone which has experienced only 73 congestion-event hours during 2005. The DAY Control Zone had experienced 19 congestion-event hours during the three months following its Phase three integration into PJM on October 1, 2004. The Miami Fort transformer was the most frequently constrained facility in the DAY Control Zone during 2005 with 69 congestion-event hours.

Figure 7-35 - DAY Control Zone congestion-event hours (By facility): Phase 3, 2004 to December 31, 2005

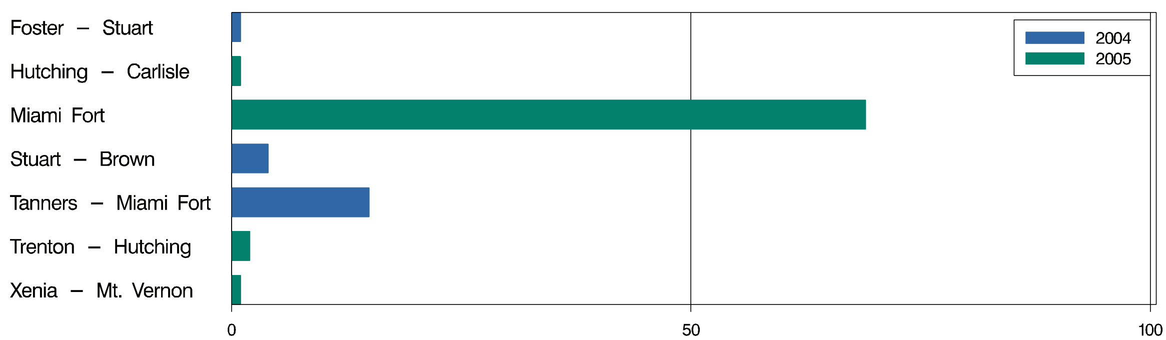
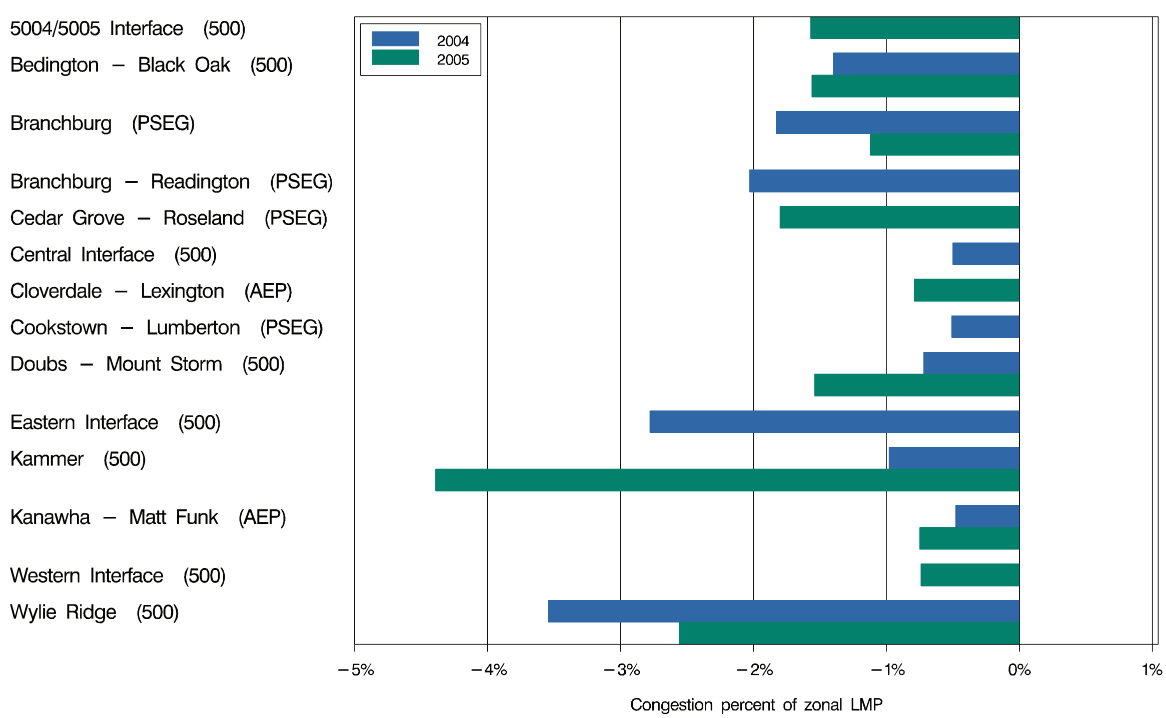


Figure 7-36 shows the congestion components of the DAY Control Zone's LMP. The Kammer and Wylie Ridge and transformer constraints caused the greatest reduction in prices in the DAY Control Zone. There were no constraints that significantly increased prices in the DAY Control Zone during 2005.

Figure 7-36 - DAY Control Zone congestion components: Phase 3, 2004 to December 31, 2005



DLCO Control Zone

Figure 7-37 illustrates constraint occurrences in the DLCO Control Zone. Following its Phase 4 integration into PJM, the DLCO Control Zone experienced 108 congestion-event hours during 2005. No facilities were constrained more than 50 hours in the DLCO Control Zone during 2005. The most frequently occurring constraint in the DLCO Control Zone was the Collier transformer with 44 congestion-event hours during 2005.

Figure 7-37 - DLCO Control Zone congestion-event hours (By facility): Calendar year 2005

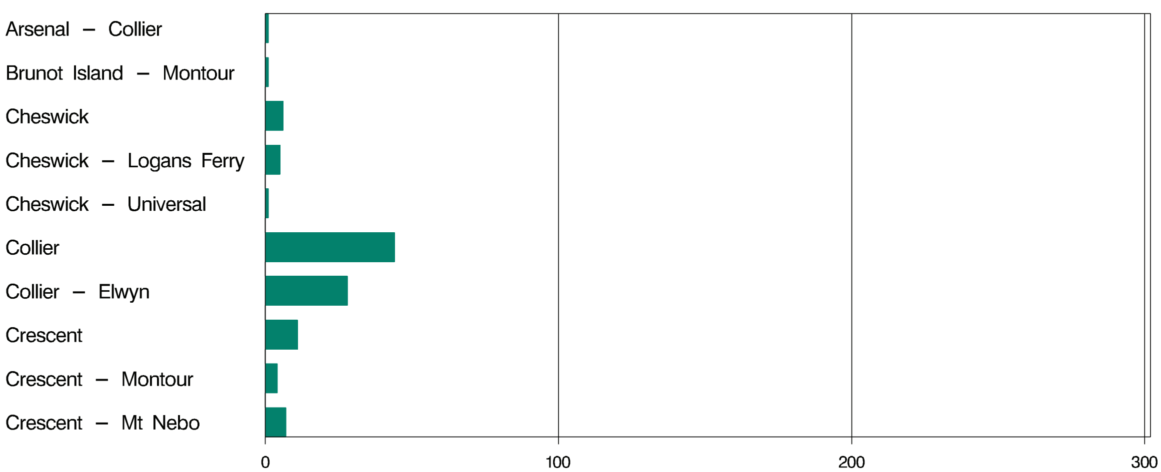
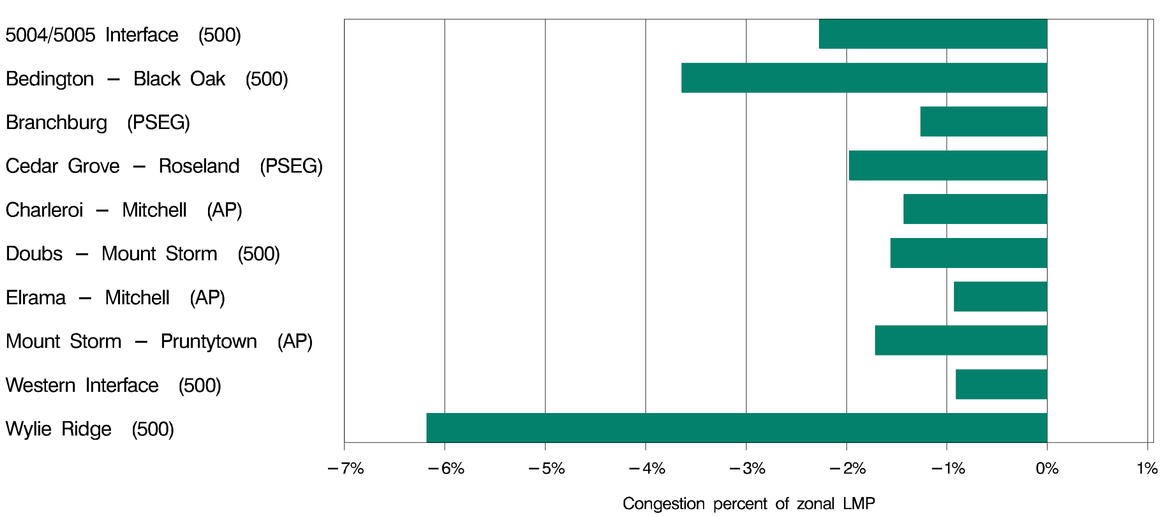


Figure 7-38 depicts the congestion components of the DLCO Control Zone's LMP. The Wylie Ridge transformer and the Bedington-Black Oak constraints caused the greatest reduction in prices in the DLCO Control Zone. There were no constraints that significantly increased prices in the DLCO Control Zone during 2005.

Figure 7-38 - DLCO Control Zone congestion components: Calendar year 2005



Southern Region Congestion-Event Hours and Congestion Components

Dominion Control Zone

Figure 7-39 illustrates constraint occurrences in the Dominion Control Zone. Following its Phase 5 integration into PJM, the Dominion Control Zone experienced 658 congestion-event hours during 2005. The Alta Vista-Dominion 115 kV line was the most frequently constrained facility in the Dominion Control Zone with 173 congestion-event hours. The Beechwood –Kerr Dam 115 kV line was the second most frequently constrained facility in the Dominion Control Zone with 128 congestion-event hours. No other Dominion Control Zone facilities were constrained more than 100 hours.

Figure 7-39 - Dominion Control Zone congestion-event hours (By facility): Phase 5, 2005

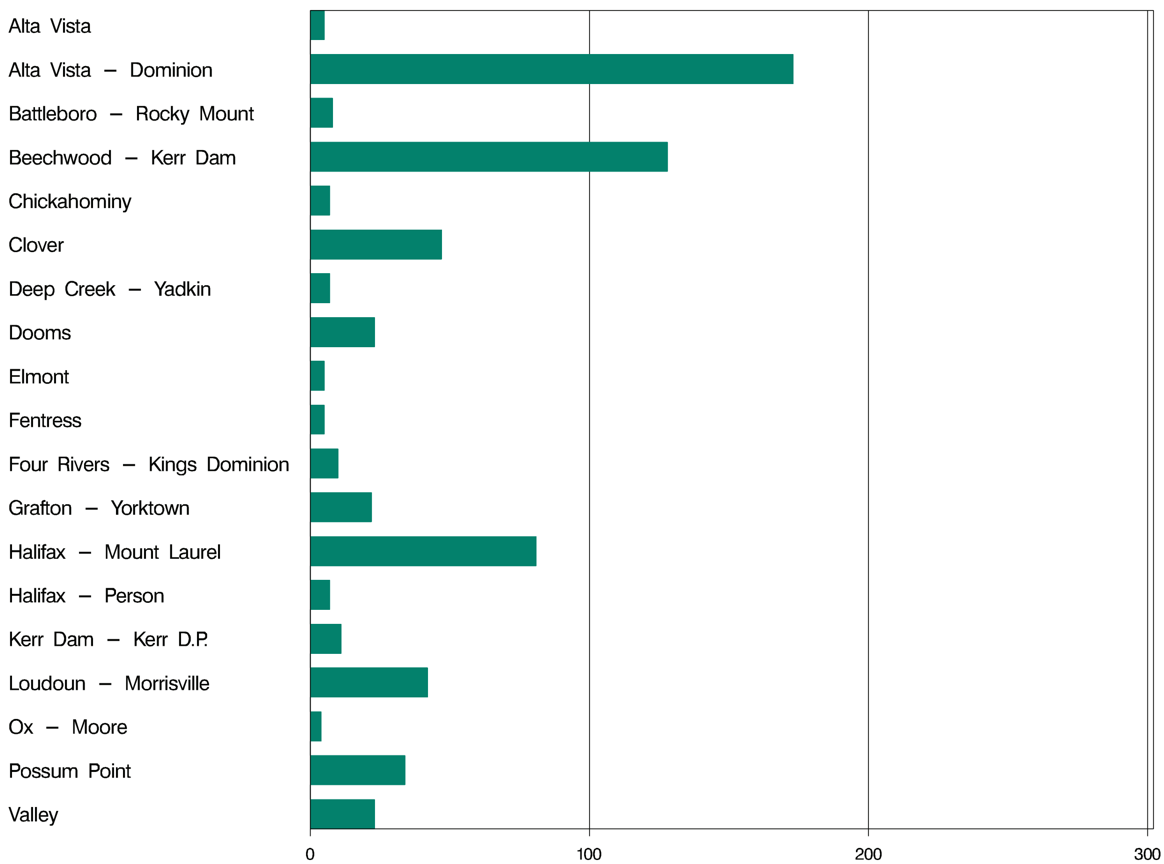


Figure 7-40 depicts the congestion components of the Dominion Control Zone's LMP. The Bedington-Black Oak and Mount Storm-Pruntytown constraints caused the greatest increase in prices in the Dominion Control Zone. The Cedar Grove-Roseland constraint caused the greatest reduction in prices in the Dominion Control Zone in 2005.

Figure 7-40 - Dominion Control Zone congestion components: Phase 5, 2005

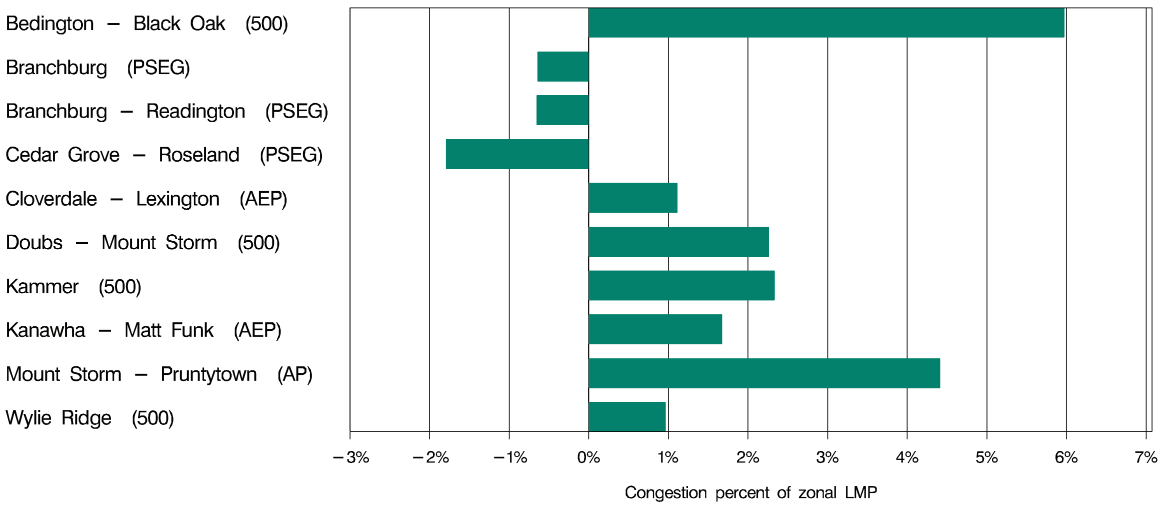


Table 7-7 lists congestion-event hours by facility type and voltage.

Table 7-7 - Congestion-event hour summary (By facility type and voltage class): Calendar years 2002 to 2005

Type	Voltage (kV)	Congestion-Event Hours 2002	2003	2004	2005	% of Congestion-Event Hours 2002	2003	2004	2005
All	All	11,662	9,711	*11,205	17,524	100%	100%	100%	100%
	765	-	-	-	16	-	-	-	0%
	500	1,888	1,985	1,809	5,494	16%	20%	16%	31%
	345	1,084	705	1,115	2,214	9%	7%	10%	13%
	230	1,474	3,016	2,340	2,537	13%	31%	21%	14%
	138	2,056	1,071	977	3,741	18%	11%	9%	21%
	115	2,527	1,018	534	1,323	22%	10%	5%	8%
	69	2,619	1,916	1,918	2,199	22%	20%	17%	13%
	34	14	0	0	0	0%	0%	0%	0%
Midwest ISO Flowgate	All	-	-	455	216	-	-	4%	1%
	500	-	-	0	3	-	-	0%	0%
	345	-	-	369	121	-	-	3%	1%
	230	-	-	4	50	-	-	0%	0%
	138	-	-	82	42	-	-	1%	0%
Interface	All	1,683	1,274	1,018	1,463	14%	13%	9%	8%
	500	586	764	397	940	5%	8%	4%	5%
	345	5	0	0	0	0%	0%	0%	0%
	230	388	103	0	81	3%	1%	0%	0%
	115	538	11	16	4	5%	0%	0%	0%
	69	166	396	605	438	1%	4%	5%	2%
Line	All	5,552	5,590	4,622	10,230	48%	58%	41%	58%
	765	-	-	-	16	-	-	-	0%
	500	1,128	917	1,328	3,219	10%	9%	12%	18%
	345	233	168	99	669	2%	2%	1%	4%
	230	658	2,104	996	1,350	6%	22%	9%	8%
	138	1,163	815	756	2,356	10%	8%	7%	13%
	115	413	187	280	1,023	4%	2%	2%	6%
	69	1,943	1,399	1,163	1,597	17%	14%	10%	9%
	34	14	0	0	0	0%	0%	0%	0%
Transformer	All	4,427	2,847	2,598	5,615	38%	29%	23%	32%
	500	174	304	84	1,332	1%	3%	1%	8%
	345	846	537	647	1,424	7%	6%	6%	8%
	230	428	809	1,340	1,056	4%	8%	12%	6%
	138	893	256	139	1,343	8%	3%	1%	8%
	115	1,576	820	238	296	14%	8%	2%	2%
	69	510	121	150	164	4%	1%	1%	1%

*2004 total includes an additional 2,512 congestion-event hours attributable to the Pathway between ComEd and PJM during Phase 2.

Post-Contingency Congestion Management Program

The PJM "Transmission Operations Manual" states in relevant part:

> The PJM [regional transmission organization] RTO Bulk Power Electric Supply System is operated so that loading on all PJM Monitored Bulk Power Transmission Facilities are within normal continuous ratings, and so that immediately following any single facility malfunction or failure, the loading on all remaining facilities can be expected to be within emergency ratings.[20]

PJM developed, tested and implemented a protocol that results in less frequent out-of-merit dispatch than had been the case under the then-current system. On August 19, 2004, the FERC accepted PJM's plan.[21] The program was implemented on September 1, 2004. The FERC noted that the expansion of this program has potential to: reduce redispatch costs in chronically congested areas in the PJM region; more accurately reflect the local benefits of avoided redispatch and enhanced reliability; reduce the potential for the exercise of local market power; reduce emissions; and allow for more efficient use of assets.

Under this post-contingency congestion management protocol, a facility may be operated to a 30-minute, short-term emergency rating if there is sufficient quick start generation capability or switching to respond to the loss of a facility. Members submit facility requests and PJM continues to evaluate candidate facilities for inclusion under this protocol. Beginning on June 1, 2005, there were 36 facilities included in this program, an increase of 21 facilities over the number as of June 1, 2004. During 2005, 136 hours of off-cost operation were avoided through the use of this protocol.

Unhedgeable Congestion and the PJM Economic Planning Process

Persistent congestion in areas within PJM and the overall level of congestion costs suggest the importance of PJM's continuing efforts to improve the sophistication of its congestion analysis.

In an order dated December 19, 2002, granting PJM full RTO status, the FERC directed PJM to revise its RTEP process to "more fully explain [...] how PJM's planning process will identify expansions that are needed to support competition" and to "provide authority for PJM to require upgrades both to ensure system reliability and to support competition."[22]

PJM's economic planning process identifies transmission upgrades needed to address unhedgeable congestion. A one-year market window is opened during which merchant solutions are solicited, through the introduction of incentives and through the posting of relevant market data. If market participants do not propose projects to resolve unhedgeable congestion within an appropriate time period, PJM will define, subject to cost-benefit analysis, transmission solutions to be implemented through the RTEP process.

20 See PJM manual, "Transmission Operations (m03), Revision 12" (October 1, 2004), p. 30.
21 108 FERC ¶ 61,196 (2004).
22 101 FERC ¶ 61,345 (2002).

Unhedgeable congestion is a central concept in defining needed transmission upgrades for implementation by third parties and in determining whether transmission upgrades pass the cost-benefit test required to be implemented via the RTEP process. PJM defines unhedgeable congestion as the cost of congestion attributable to the portion of load affected by a transmission constraint that cannot be supplied by economic local generation or hedged with available FTRs or ARRs.[23, 24]

Economic local generation is defined to be the generation capacity that is online at the time of the constraint and available to constrained bus load at offer prices no greater than the PJM system marginal price, where the PJM system marginal price represents the systemwide unconstrained price of energy. Self-scheduled generators are deemed to have price offers of zero. Units that are running out of economic merit order at an offer-capped price pursuant to Section 6 of Schedule 1 of the Operating Agreement are excluded from economic local generation.[25]

The value of economic local generation as a hedge is not correctly calculated in the current methodology. It is not reasonable to assume, as the current method does, that a local generation owner would enter into a contract at its offer level or the system marginal price rather than at the market-clearing local price reflecting congestion. However, economic local generation would be a hedge if effectively owned by load.

The current methodology overstates the value of economic generation as a congestion hedge unless economic local generation is owned by load. The result of such an overstatement would be to undervalue the cost of unhedgeable congestion and to undervalue transmission upgrades. This, in turn, would lead to economic transmission upgrades being rejected under the cost-benefit calculation when they are actually cost effective.

Constraints with Open Market Window

Table 7-8 identifies the facilities for which a market window has been opened. Depending upon their initiation dates, market windows for some of these facilities closed beginning in March 2005. Proposed solutions may only be designated as a “market solution,” and thus be eligible for expedited processing, following the close of the associated market window and by request of the developer. Since the program’s inception, 74 facilities have had market windows opened with 54 of these closing during 2005.

23 104 FERC ¶ 61,124 (2003).

24 Unhedgeable congestion is calculated on an hourly basis in the manner described by the formula presented in: PJM Interconnection, L.L.C., Compliance Filing, Docket No. RT01-2-005 (August 25, 2003).

25 109 FERC ¶61,067 (2004) at p. 49.

Table 7-8 - Constraints with open market window

One-Year Market Window is Open for the Following Congested Facilities	Market Window Open Date	Market Window Close Date	Location of Facility Based on Transmission Owner Zones	Studies Completed
Adams - Brunswick 230 kV "X-2224"	4-Mar-04	4-Mar-05	PSEG	Yes
Bedington - Black Oak 500 kV (Voltage)	4-Mar-04	4-Mar-05	AP	No
Bedington - Black Oak 500 kV (Thermal)	4-Mar-04	4-Mar-05	AP	Yes
Greystone - Portland 230 kV	4-Mar-04	4-Mar-05	Met-Ed / JCPL	Yes
PJM West 500 kV	4-Mar-04	4-Mar-05	Multiple Zones	Yes
North Wales - Whitpain 230 kV	4-Mar-04	4-Mar-05	PECO	Yes
Eastern Interface	4-Mar-04	4-Mar-05	Multiple Zones	No
Jackson 230/115 kV	4-Mar-04	4-Mar-05	Met-Ed	Yes
Yorkana 230/115 kV	4-Mar-04	4-Mar-05	Met-Ed	Yes
Cedar Grove - Clifton 230 kV "K-2263"	4-Mar-04	4-Mar-05	PSEG	No
Adams - Bennetts Lane 230 kV "X-2224"	4-Mar-04	4-Mar-05	PSEG	Yes
Brunswick - Edison 138 kV	4-Mar-04	4-Mar-05	PSEG	No
Sheildalloy - Vineland 69 kV	4-Mar-04	4-Mar-05	AECO	Yes
Edison - Meadow Road 138 kV "R-1318"	4-Mar-04	4-Mar-05	PSEG	Yes
Elroy - Hosensack 500 kV	4-Mar-04	4-Mar-05	PECO / PPL	Yes
Edgewood - N. Salisbury 69 kV	4-Mar-04	4-Mar-05	DPL	Yes
Cedar Interface	4-Mar-04	4-Mar-05	AECO	Yes
Northern PECO Voltage Interface	4-Mar-04	4-Mar-05	PECO	Yes
Athenia - Saddlebrook 230 kV	4-Mar-04	4-Mar-05	PSEG	Yes
Central Interface	4-Mar-04	4-Mar-05	Multiple Zones	No
Laurel - Woodstown 69 kV	4-Mar-04	4-Mar-05	AECO	Yes
DuPont Seaford - Laurel 69 kV	4-Mar-04	4-Mar-05	DPL	Yes
West Interface	4-Mar-04	4-Mar-05	Multiple Zones	No
Landis - Minotola 69 kV	4-Mar-04	4-Mar-05	AECO	Yes
Sammis - Wylie Ridge 345 kV	4-Mar-04	4-Mar-05	AP	Yes
Lewis - Motts Farm 69 kV	4-Mar-04	4-Mar-05	AECO	Yes
Plymouth Meeting - Whitpain 230 kV "220-14"	4-Mar-04	4-Mar-05	PECO	Yes
Keeney 500/230 kV "AT51"	4-Mar-04	4-Mar-05	DPL	Yes
Plymouth Meeting - Whitpain 230 kV "220-13"	4-Mar-04	4-Mar-05	PECO	Yes
Martins Creek - Morris Park 230 kV	4-Mar-04	4-Mar-05	PPL / JCPL	Yes
Bergen - Leonia 230 kV	1-Apr-04	1-Apr-05	PSEG	Yes
Bergen - Hoboken 230 kV	1-Apr-04	1-Apr-05	PSEG	Yes
Wylie Ridge 500/345 kV #5	1-Apr-04	1-Apr-05	AP	Yes
Kammer - Harrison Tap 500 kV	1-Apr-04	1-Apr-05	AP	No
Branchburg 500/230 kV #1	18-May-04	18-May-05	PSEG	Yes
Branchburg 500/230 kV #2	18-May-04	18-May-05	PSEG	Yes
Wylie Ridge 500/345 kV #7	20-Jul-04	20-Jul-05	AP	Yes
Keeney 500/230 kV "AT50"	20-Jul-04	20-Jul-05	DPL	Yes
Branchburg - Flagtown 230 kV	20-Jul-04	20-Jul-05	PSEG	No
Bayonne - Marion 138 kV	29-Nov-04	29-Nov-05	PSEG	No
Roseland - Whippany 230 kV	29-Nov-04	29-Nov-05	JCPL/PSEG	No
Jackson 230/115 kV "5"	29-Nov-04	29-Nov-05	Met-Ed	No
Glasgow - Mt Pleasant 138 kV	29-Nov-04	29-Nov-05	DPL	No
Richmond - Waneeta 230 kV	29-Nov-04	29-Nov-05	PECO	No
Red Lion 500/230 kV "AT50"	29-Nov-04	29-Nov-05	DPL	No
Doubs - Mt Storm 500 kV	29-Nov-04	29-Nov-05	AP/Dominion	No
Beckett - Paulsboro 69 kV	29-Nov-04	29-Nov-05	AECO	No
Hudson 230/138 kV #2	29-Nov-04	29-Nov-05	PSEG	No
Brunner - Yorkana 230 kV	29-Nov-04	29-Nov-05	PPL/Met-Ed	No
Wye Mills 138/69 kV "AT-2"	29-Nov-04	29-Nov-05	DPL	No
Sickler 230/69 kV #1	29-Nov-04	29-Nov-05	AECO	No
Cedar - Sands Point 69 kV	29-Nov-04	29-Nov-05	AECO	No
Talbot-Trappe 69 kV	29-Nov-04	29-Nov-05	DPL	No
Fort Martin - Pruntytown 500 kV	1-Dec-04	1-Dec-05	AP	No
Edge Moor - Harmony 230 kV	2-Mar-05	2-Mar-06	DPL	No
N Philadelphia - Waneeta 230 kV	2-Mar-05	2-Mar-06	PECO	No
Delco Tap - Mickleton 230 kV	2-Mar-05	2-Mar-06	PECO/AECO	No
Cloverdale - Lexington 500 kV	5-May-05	5-May-06	AEP/Dominion	No
Mt Storm - Pruntytown 500 kV	8-Nov-05	8-Nov-06	AP/Dominion	No
Chickahominy 500/230 kV transformer #1	8-Nov-05	8-Nov-06	Dominion	No
Conastone - Northwest 230 kV "2322"	8-Nov-05	8-Nov-06	BGE	No
Keystone - Juniata 500 kV + Conemaugh - Juniata 500 kV interface	8-Nov-05	8-Nov-06	Multiple Zones	No
Center - Westport 115 kV #2	8-Nov-05	8-Nov-06	BGE	No
Bair - Hill 115 kV	8-Nov-05	8-Nov-06	Med-Ed	No
Absecon - Lewis 69 kV #1	8-Nov-05	8-Nov-06	AECO	No
Cedar - Motts 69 kV #5	8-Nov-05	8-Nov-06	AECO	No
Brunner - West Hempfield 230 kV	8-Nov-05	8-Nov-06	PPL	No
Conastone 500/230 kV #2	20-Dec-05	20-Dec-06	BGE	No
Whitpain 500/230 kV #3	20-Dec-05	20-Dec-06	PECO	No
Possum Point 230/115 kV #9	20-Dec-05	20-Dec-06	Dominion	No
Cheswold - Kent 69 kV	20-Dec-05	20-Dec-06	DPL	No
Higbee - Ontario 69 kV	20-Dec-05	20-Dec-06	AECO	No
Edgemoor 230/138 kV "AT20"	20-Dec-05	20-Dec-06	DPL	No
Northwest - Devon 138 kV "11411"	20-Dec-05	20-Dec-06	ComEd	No

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. In PJM, FTRs have been made 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]

FTRs and ARRs are 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. ARRs provide holders with revenues or charges based on the locational price difference between ARR sources and sinks determined in the Annual FTR Auction.[2] These price differences are based on the bid prices of participants in the Annual FTR Auction Market. 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. 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.

Firm transmission customers have access to FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission customers receive requested FTRs to the extent that they are consistent both with the physical capability of the transmission system and with FTR requests of other eligible customers.

Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[3] Firm transmission customers have the option either to take allocated ARRs or to take the underlying FTRs through a process called self-scheduling.

PJM also runs Monthly FTR Auctions designed to permit bilateral FTR transactions and to allow any market participant to buy residual system FTRs. PJM introduced 24-hour FTRs into the Monthly Auctions for the 2003 to 2004 planning period. At the same time, PJM also added annual and monthly FTR option products to the FTR Auction Market. Unlike standard FTRs, the FTR options can never be a financial liability.

During the last two calendar years, PJM has 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. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[4]

1 PJM network and firm, long-term point-to-point transmission service customers are referred to as eligible customers.

2 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.

3 87 FERC ¶ 61,054 (1999).

4 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

- **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,[5] and the Allegheny Power Company (AP) Control Zone.[6]

- **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).[7]

- **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, ComEd, AEP and DAY Control Zones 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.

The *2005 State of the Market* Report focuses on two FTR/ARR planning periods: the 2004 to 2005 planning period which covers June 1, 2004, to May 31, 2005, and the 2005 to 2006 planning period which covers June 1, 2005, through May 31, 2006.[8]

For the 2005 to 2006 planning period (June 1, 2005, through May 31, 2006), ARR allocations were provided to eligible market participants in the Mid-Atlantic Region and AP Control Zone. The choice of ARRs or direct allocation FTRs was available in the recently integrated ComEd, AEP, DAY, DLCO and Dominion Control Zones. Participants in newly integrated control zones retain the option of ARR allocations or direct allocation FTRs for the two planning periods following integration. After that, they can participate fully in the FTR Markets and receive ARR allocations through the PJM allocation process. For example, since its May 1, 2004, integration, direct allocation FTRs were available to participants in the ComEd Control Zone for the 2004 to 2005 planning period and for the 2005 to 2006 planning period. For subsequent periods, eligible customers in the ComEd Control Zone will be full participants in the ARR allocation process.

5 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

6 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 the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

7 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).

8 Annual FTR accounting changed from calendar year to planning period beginning with the 2003 to 2004 planning period. The transition to this new accounting period required the 2003 calendar year accounting to be extended by five months to encompass January 1, 2003, through May 31, 2004.

Overview

Financial Transmission Rights (FTRs)

- **Products.** FTR products include FTR obligations and FTR options. Each of these is available for 24-hour, off-peak and on-peak periods.

- **Supply and Demand.** PJM operates an Annual FTR Auction Market for all zones in the PJM footprint. Participants in newly integrated zones must choose to receive either an FTR allocation or an ARR allocation before the start of Annual FTR Auction. In the Annual Auction Market, total FTR Auction demand was 871,841 MW during the 2005 to 2006 planning period, up from 861,323 MW during the 2004 to 2005 planning period. The Auction Market cleared 141,179 MW (16.2 percent of demand), leaving 730,662 MW of uncleared bids. In the FTR Auction Market for the 2004 to 2005 planning period, the demand was 861,323 MW while the market cleared only 119,629 MW (13.9 percent of demand), leaving uncleared bids of 741,694 MW. Under the Annual FTR Auction, there is no limit on FTR demand. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and numerous combinations of FTRs are feasible. The principal binding constraints limiting the supply of FTRs were the Jefferson 138 kV line, the Mahans Lane 138 kV line and the Branchburg 500/230 kV transformer.

  In the allocation of FTRs or ARRs for the ComEd, AEP, DAY, DLCO and Dominion Control Zones, total demand for annual FTR allocations was 42,641 MW for the 2005 to 2006 planning period, down from 65,757 MW for the 2004 to 2005 planning period. This decrease was the net result of a number of factors including the AP Control Zone becoming ineligible for direct allocation FTRs, increased demand by customers in the ComEd Control Zone for ARRs rather than directly allocated FTRs and the integration of Dominion. Demand for allocations cleared at 39,429 MW, leaving uncleared bids of 3,212 MW. The principal binding constraints limiting the supply of allocated FTRs were the Chesterfield-Lakeside 230 kV line, the Kanawha River-Matt Funk 345 kV line, the South Canton transformer and the Crete-St Johns 345 kV line, and the Bedington-Black Oak interface.

  In addition to the Annual FTR Auction and allocation markets, PJM conducts Monthly FTR Auction Markets covering the entire PJM footprint, to allow participants to buy and sell any residual transmission entitlement that is available after FTRs are awarded from the Annual FTR Auction. Any market participant can participate in the Monthly Auctions as a buyer or as a seller.

- **Ownership Concentration.** Ownership of FTRs is moderately concentrated and maximum market shares exceed 20 percent in some cases based on the results of the Annual Auction. Given PJM's Annual and Monthly FTR Auctions, the market shares may fluctuate when FTR-owning entities trade, buy or sell the instruments.

- **Volume.** Of 914,483 MW in annual FTR requests for the 2005 to 2006 planning period, 180,609 MW (19.7 percent) were cleared. Of 927,081 MW[9] in annual FTR requests for the 2004 to 2005 planning period, 179,950 MW (19.4 percent) were cleared.

9 The number reported here is slightly higher than the number reported in *2004 State of the Market Report*, which was 924,154 MW, because the number reported here includes 1,524 MW of requested bids in the DLCO Control Zone and 1,402 MW of additional requested bids in the AEP and DAY Control Zones.

- **Price.** For the 2005 to 2006 planning period, 84.3 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 89.1 percent for less than $2 per MWh. The overall average prices paid for annual FTR obligations were $1.56 per MWh for 24-hour, $0.40 per MWh for on-peak and $0.33 per MWh for off-peak FTRs. Comparable prices for the 2004 to 2005 planning period were $1.27 per MWh for 24-hour, $0.16 per MWh for on-peak and $0.13 per MWh for off-peak FTRs. The overall average prices paid for 2005 to 2006 planning period annual FTR obligations and options were $0.10 per MWh and $0.18 per MWh, respectively, compared to $0.31 per MWh and $0.19 per MWh, respectively, in the 2004 to 2005 planning period.

- **Revenue.** Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,672 million of FTR revenues during the first seven months of the 2005 to 2006 planning period and $1,118 million during the 12-month 2004 to 2005 planning period.[10]

- **Revenue Adequacy.** FTRs were paid at 91 percent of the target allocation level for the 2005 to 2006 planning period, through the end of calendar year 2005.[11] FTRs were 100 percent revenue adequate during the 2004 to 2005 planning period.

Auction Revenue Rights (ARRs)

- **Supply and Demand.** Total demand in the annual ARR allocation was 82,343 MW for the 2005 to 2006 planning period, up from 55,128 MW during the 2004 to 2005 planning period and 39,888 MW during the 2003 to 2004 planning period. ARR demand is limited by the total amount of network and long-term, firm point-to-point transmission service. ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs, and numerous combinations of ARRs are feasible.

- **Volume.** Of 82,343 MW in ARR requests for the 2005 to 2006 planning period, 59,410 MW were allocated. Eligible market participants subsequently self-scheduled 32,631 MW (55 percent) of these allocated ARRs as annual FTRs. Of 55,128 MW in ARR requests for the 2004 to 2005 planning period, 33,589 MW were allocated. Eligible market participants subsequently self-scheduled 13,061 MW (39 percent) of these allocated ARRs as annual FTRs.

- **Revenue.** Revenues from the Annual FTR Auction are first distributed to ARR holders based on ARR target allocations. If that revenue is not sufficient to meet ARR target allocations, then revenues from Monthly FTR Auctions are used to make up any shortfall. For the 2005 to 2006 planning period, the ARR target allocations were $870 million while PJM collected $892 million from the combined Annual and Monthly FTR Auctions through the end of calendar year 2005, making ARRs revenue adequate. During the 2004 to 2005 planning period, the ARR target allocations were $345 million while PJM collected $385 million from the combined Annual and Monthly FTR Auctions, making ARRs revenue adequate.

10 See Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period."
11 See Section 7, "Congestion," for an additional discussion of FTR revenue adequacy.

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 allows a market valuation of FTRs. The 2005 FTR Auction Market results were competitive and succeeded in providing all qualified market participants with equal access to FTRs. A potential barrier to competition was removed by implementing the rules which explicitly allow that the ARRs with positive economic values (FTRs in newly integrated zones) follow load as load shifts among suppliers, although the fact that the underlying FTRs do not also follow load in the case of self-scheduled ARRs should also be addressed. FTRs were paid at 100 percent of the target allocation level for the 12-month planning period that ended May 31, 2005, and at 91 percent of the target allocation level for the first seven months of the planning period ending May 31, 2006. Although in the aggregate, FTRs provided a hedge against 100 percent of the target allocation level during the 12-month period that ended May 31, 2005, 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.

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 2005 to 2006 planning period, the auction covered all zones. Eligible participants in the AEP, DAY, DLCO and Dominion Control Zones received transitional, direct allocation FTRs.[12]

FTRs are financial instruments that entitle their holders to receive revenue based on prices 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. 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 may receive congestion credits between zero and their target allocations. When FTR holders receive their target allocation, the associated FTRs are fully funded.

FTR Products

There are two FTR product types: 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 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.

12 AEP and DAY joined PJM on October 1, 2004. DLCO joined PJM on January 1, 2005. Dominion joined PJM on May 1, 2005.

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 obtain annual FTRs. Now all qualified market participants can participate in the Annual FTR Auction. 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. As a result, total demand for FTRs has increased.

Supply and Demand

The principal mechanism for obtaining FTRs is the Annual FTR Auction, including the ability to self-schedule the underlying FTRs in place of allocated ARRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and numerous combinations of FTRs are feasible. FTRs can also be obtained as direct allocation FTRs (available to customers in recently integrated control zones), in Monthly FTR Auctions and via bilateral trades of existing FTRs.

During any planning period including newly integrated control zones, eligible customers in those control zones can elect to receive either annual ARRs or direct allocation FTRs at the start of the first two full planning periods of their PJM membership, but no longer have the direct allocation FTR option after the transition period. Table 8-1 summarizes the availability of ARRs and direct allocation FTRs within the different regions and control zones.

Table 8-1 - Eligibility for ARRs vs. directly allocated FTRs

	PJM Integration Date	ARRs	Direct Allocation FTRs
Mid-Atlantic	01-Apr-99	Yes	No
AP	01-Apr-02	Yes	No
ComEd	01-May-04	Yes	Through 2005/2006 planning period
AEP/DAY	01-Oct-04	Yes	Through 2006/2007 planning period
DLCO	01-Jan-05	Yes	Through 2006/2007 planning period
Dominion	01-May-05	Yes	Through 2007/2008 planning period

Each March, 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 maximizing the net revenue based on offer-based value of FTRs.[13] Auction participation is not restricted to any class of customers, and any market participant can make offers for available FTRs. ARR holders wishing to self-schedule their previously allocated ARRs as FTRs must initiate the self-scheduling 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 ARR. Self-scheduled FTRs clear as price-taking FTR bids that are not eligible to set auction price.

13 Both Annual and Monthly 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.

- **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.

PJM also conducts Monthly FTR Auctions during which market participants can bid on monthly FTRs available due to residual transmission system capability or the sale of FTRs by participants, for the following month. These are single-round auctions in which market participants make offers for FTRs and FTR holders can offer monthly segments of their FTRs.

FTRs can also be obtained in two other ways. Eligible participants can trade FTRs through the PJM-administered, bilateral market or market participants can trade FTRs among themselves without PJM involvement.

Table 8-2 shows that for the 2005 to 2006 planning period, 141,179 MW of annual FTR bids were cleared in the Annual FTR Auction for all zones in the PJM footprint while 39,429 MW of annual FTR allocation requests were cleared in the annual FTR allocation for the ComEd, AEP, DAY, DLCO and Dominion Control Zones. A total of 978,462 MW were bid, offered, or requested to be allocated. By comparison, for the 2004 to 2005 planning period, a total of 977,861 MW of annual FTRs were bid, offered, or requested to be allocated.

Table 8-2 - Annual FTR Market volume: Planning period 2005 to 2006

	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)
Buy Bid (Auction)			
All PJM Zones	84,381	871,841	141,179
Bid Request (Allocation)			
ComEd	34	1,170	1,138
AEP/DAY	639	24,492	24,487
DLCO	48	632	489
Dominion	283	16,348	13,315
Total	85,385	914,483	180,609
Sell Offer (Auction)			
All PJM Zones	11,067	63,979	4,543
TOTAL	96,452	978,462	185,152

As Table 8-2 shows, annual FTR demand for both the auction and allocation in PJM was 914,483 MW during the 2005 to 2006 planning period, compared with 927,081 MW for the 2004 to 2005 planning period.

Under the current rules, participants may submit unlimited bids for FTRs based on a variety of financial strategies. FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and numerous combinations of FTRs are feasible. For the requested FTRs for the 2005 to 2006 planning period, bids for 185,152 MW were met by available supply, leaving 793,310 MW of demand unfulfilled. Table 8-3 lists the principal constraints that precluded awarding all FTRs requested.

Table 8-3 - Annual FTR Auction and allocation principal binding transmission constraints: Planning period 2005 to 2006

	Principal Constraints
Mid-Atlantic/AP/ComEd	Jefferson 138 kV, Mahans Lane 138 kV, Branchburg transformer derated
AEP/DAY	Kanawha River-Matt Funk 345 kV
DLCO	South Canton transformer, Crete-St Johns 345 kV
Dominion	Bedington-Black Oak Interface, Chesterfield-Lakeside 230 kV

In addition to the Annual and Monthly FTR Auctions, FTRs can be traded between market participants through bilateral transactions. Bilateral activity was consistent with previous years, with 4,226 MW of FTRs traded in calendar year 2005, as compared to 1,650 MW[14] in calendar year 2004, 1,352 MW in calendar year 2003 and 7,173 MW in calendar year 2002.

Ownership Concentration

The ownership of FTR products resulting from the 2005 to 2006 Annual FTR Auction was analyzed. The FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly FTR Auction Market or secondary bilateral market.

Herfindahl-Hirschman Index (HHI) results for each FTR product are based on the outcome of the Annual FTR Auction. For FTR obligations, HHIs were found to be 1144 for 24-hour, 1237 for off-peak and 1107 for on-peak FTR products while maximum market shares were 22 percent for 24-hour, 20 percent for off-peak and 18 percent for on-peak FTR products.

For FTR options, HHIs were found to be 8173 for 24-hour, 1420 for off-peak and 1581 for on-peak products while maximum market shares were 90 percent for 24-hour, 25 percent for off-peak and 26 percent for on-peak FTR products.

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.

14 This number was updated for 2004 calendar year.

Market Performance

Volume

For the entire PJM footprint for the 2005 to 2006 planning period, 180,609 MW of annual FTRs, from both Annual FTR Auction and direct allocation FTR for new zones, were purchased and allocated out of 914,483 MW bid and requested. For Annual FTR Auction excluding request for direct allocation FTR, 145,722 MW were purchased and sold out of 935,820 MW bid and offered. (See Table 8-2.) Eligible market participants converted 32,631 MW of ARRs into annual FTRs. In comparison, during the 2004 to 2005 planning period, 179,950 MW were purchased and allocated, with 93,344 MW purchased and allocated in the Mid-Atlantic Region and 8,874 MW purchased and allocated in the AP Control Zone. For the 2004 to 2005 planning period, eligible market participants converted 13,061 MW of Mid-Atlantic Region ARRs into annual FTRs.

Price

Table 8-4 shows average prices paid for FTR obligations during the 2004 to 2005 and the 2005 to 2006 planning period.

Table 8-4 shows the overall average prices paid for annual FTR obligations. For the 2005 to 2006 planning period, annual FTR obligation prices were $1.56 per MWh for 24-hour, $0.40 per MWh for on-peak and $0.33 per MWh for off-peak FTRs. Comparable prices for the 2004 to 2005 planning period were $1.27 per MWh for 24-hour, $0.16 per MWh for on-peak and $0.13 per MWh for off-peak FTRs.

The overall average prices paid for the 2005 to 2006 planning period annual FTR obligations and options were $0.10 per MWh and $0.18 per MWh, compared to $0.31 per MWh and $0.19 per MWh, in the 2004 to 2005 planning period. Average prices in Monthly FTR Auctions increased to $0.18 per MWh in 2005 from $0.10 per MWh in 2004.

Table 8-4 - Annual prices for FTR obligations

Planning Period	24-Hour ($/MWh)	On Peak ($/MWh)	Off Peak ($/MWh)
2004/2005	$1.27	$0.16	$0.13
2005/2006	$1.56	$0.40	$0.33

Table 8-5 shows the Annual FTR Auction data. (Table 8-2 shows both Annual Auction data and annual allocation requests.) A total of 871,841 MW were bid and a total of 63,979 MW were offered. By comparison, for the 2004 to 2005 planning period, a total of 927,081 MW were bid and requested and a total of 50,780 MW were offered.

Table 8-5 - Annual FTR Auction Market volume, price and revenue: Planning period 2005 to 2006

	Bids	Bid MW	Cleared MW	Average Bid Price ($/MWh)	Average Cleared Price ($/MWh)	Revenue
All PJM Zones						
Buy and Self-Scheduled Bids	84,381	871,841	141,179	$0.20	$0.71	$881,747,900
Sell Offers	11,067	63,979	4,543	$0.09	$0.00	($109,966)
Net	95,448	935,820	145,722	$0.19	$0.69	$881,637,934

Table 8-5 shows the number of bids and the volume, price and revenue for buy and sell bids, as well as totals for the sum of bids and volume and net revenue for the Annual FTR Auction activity. Table 8-6 splits the buy activity into its buy bid and self-scheduled FTR components.

Table 8-6 shows buy activity in terms of its bid and self-scheduled components. Self-scheduled FTRs were priced $1.60 per MWh higher than bid FTRs, up $0.20 per MWh from a year ago, while Mid-Atlantic Region, AP and ComEd Control Zones buy-bids were up $0.09 per MWh from the weighted bid price of 2004 to 2005 planning period.

The average price paid in the Monthly FTR Auctions during the first seven months of the 2005 to 2006 planning period was $0.10 per MWh, compared with $0.09 MWh over the 2004 to 2005 planning period.

Table 8-6 - Annual FTR Auction bid volume, price and revenue: Planning period 2005 to 2006

	Bids	Bid MW	Cleared MW	Average Bid Price ($/MWh)	Average Cleared Price ($/MWh)	Revenue
All PJM Zones						
Buy Bids	79,809	839,210	108,549	$0.20	$0.34	$326,145,970
Self-scheduled Bids	4,572	32,631	32,631	NA	$1.94	$555,601,930

The 2005 to 2006 planning period's price duration curve in Figure 8-1 shows that 84.3 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 89.1 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 buy-bid price duration curve: Planning period 2005 to 2006

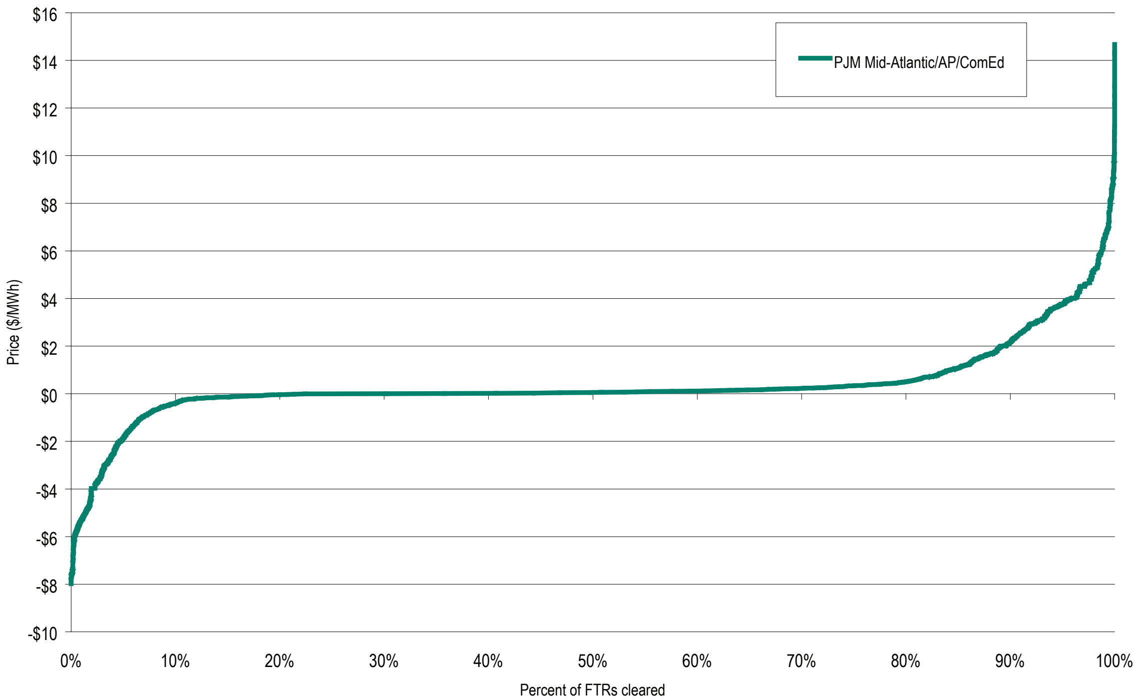
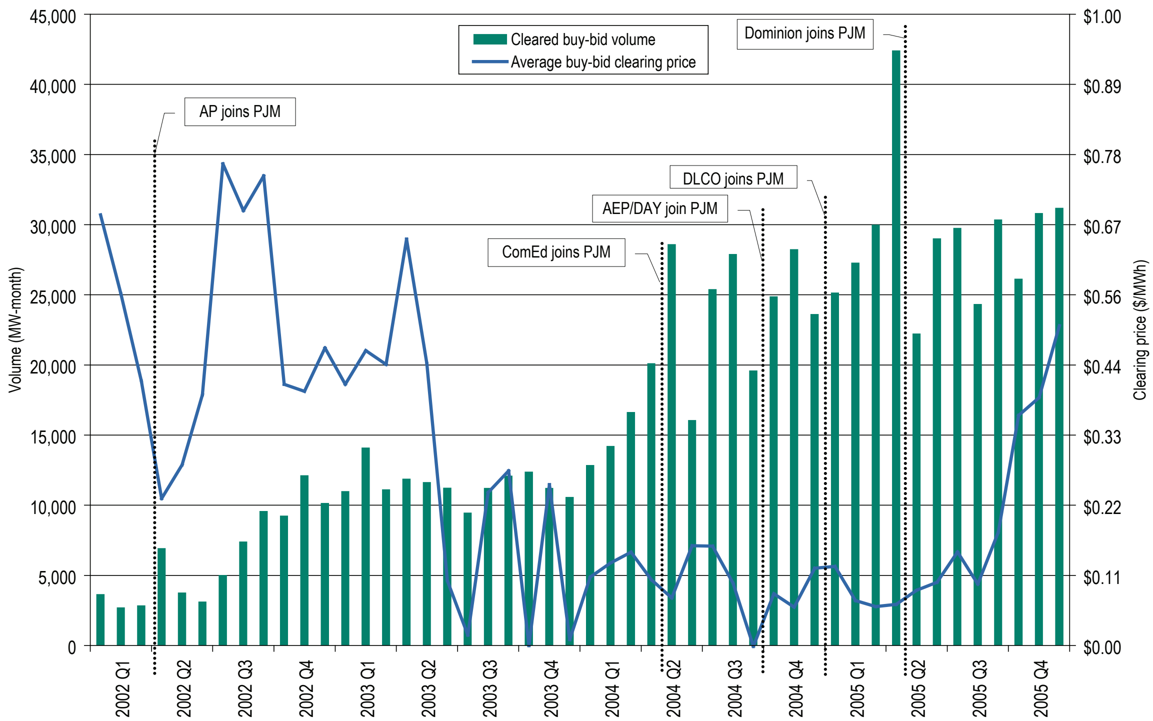


Figure 8-2 presents Monthly FTR Auction cleared-bid volume and average buy-bid clearing price. It shows that the average cleared-bid price dropped from 2002 to 2003 and 2004, but then rose in 2005. Volume steadily increased from 2002 through 2005.

Figure 8-2 - Monthly FTR Auction cleared buy-bids and average buy-bid price: Calendar years 2002 to 2005



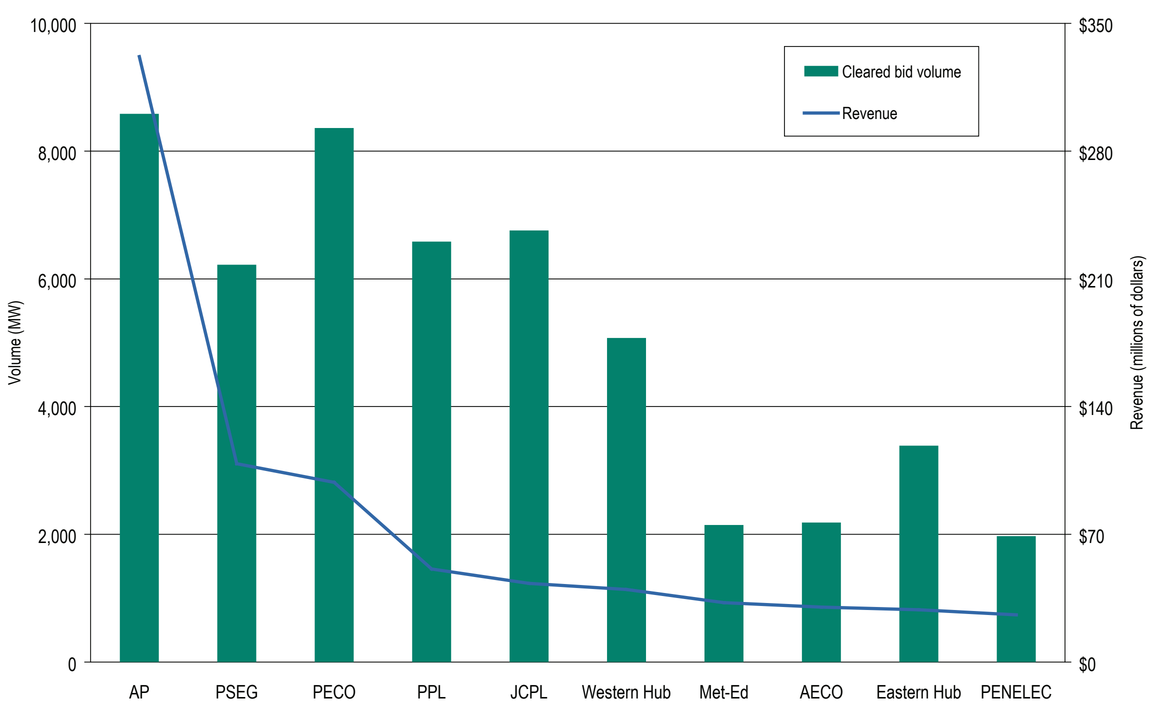
Revenue

Table 8-5 shows Annual FTR Auction summary data. During the 2005 to 2006 planning period, the Annual FTR Auctions for the ComEd Control Zone, AP and the Mid-Atlantic Region netted $881.6 million in revenue, with buyers paying $881.7 million and sellers receiving $0.1 million. By contrast, for the 2004 to 2005 planning period, the Mid-Atlantic Region and the ComEd Control Zone Annual FTR Auction netted $369.6 million in revenue, with buyers paying $380 million and sellers receiving $10.4 million.

Annual 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 2005 to 2006 planning period. FTRs to these sinks accounted for $790 million or about 89.6 percent of all revenue paid[15] in the Annual FTR Auction and constituted 36.3 percent of all FTRs bought in the Annual FTR Auction for the 2005 to 2006 planning period.

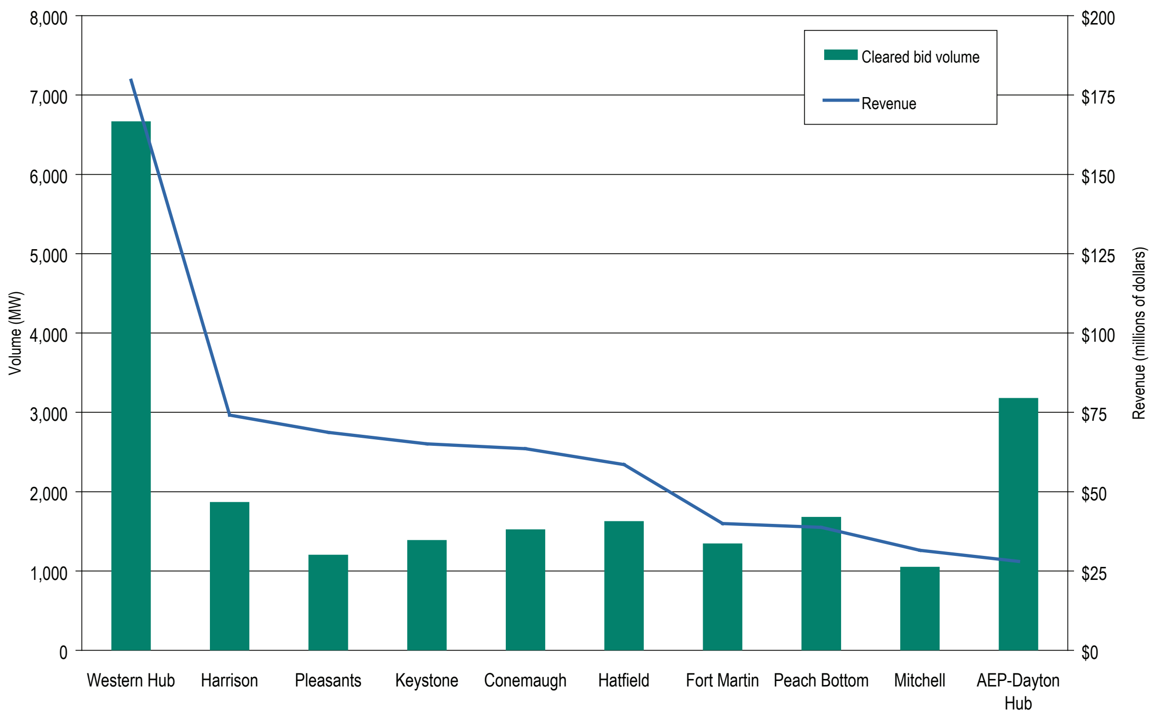
Figure 8-3 - Highest revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2005 to 2006



15 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 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 2005 to 2006 planning period. FTRs from these sources accounted for $648 million or about 73.5 percent of all revenue paid and included 15.3 percent of all FTRs bought in the Annual FTR Auction. These sources are generally located at large generating facilities throughout the Mid-Atlantic Region.

Figure 8-4 - Highest revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2005 to 2006



Monthly 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 FTR Auction revenue during the first seven months of the 2005 to 2006 planning period. FTRs to these sinks accounted for $42.8 million and included 18.1 percent of all FTRs bought in Monthly FTR Auctions.

Figure 8-5 - Highest revenue producing FTR sinks purchased in the Monthly FTR Auctions: Planning period 2005 to 2006 through December 31, 2005

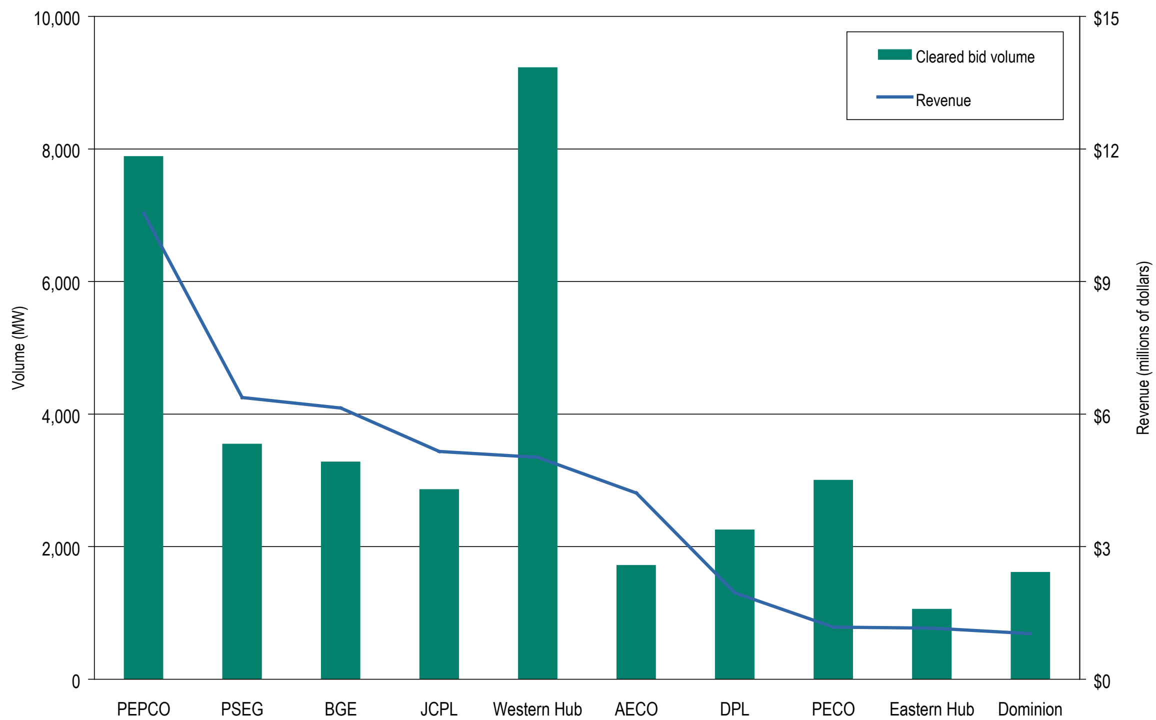


Figure 8-6 summarizes total revenue associated with all FTRs, regardless of sink, from the 10 FTR sources that produced the most Monthly FTR Auction revenue during the first seven months of the 2005 to 2006 planning period. FTRs from these sources accounted for $54.4 million and included 13.9 percent of all FTRs bought in Monthly FTR Auctions.

Figure 8-6 - Highest revenue producing FTR sources purchased in Monthly FTR Auctions: Planning period 2005 to 2006 through December 31, 2005

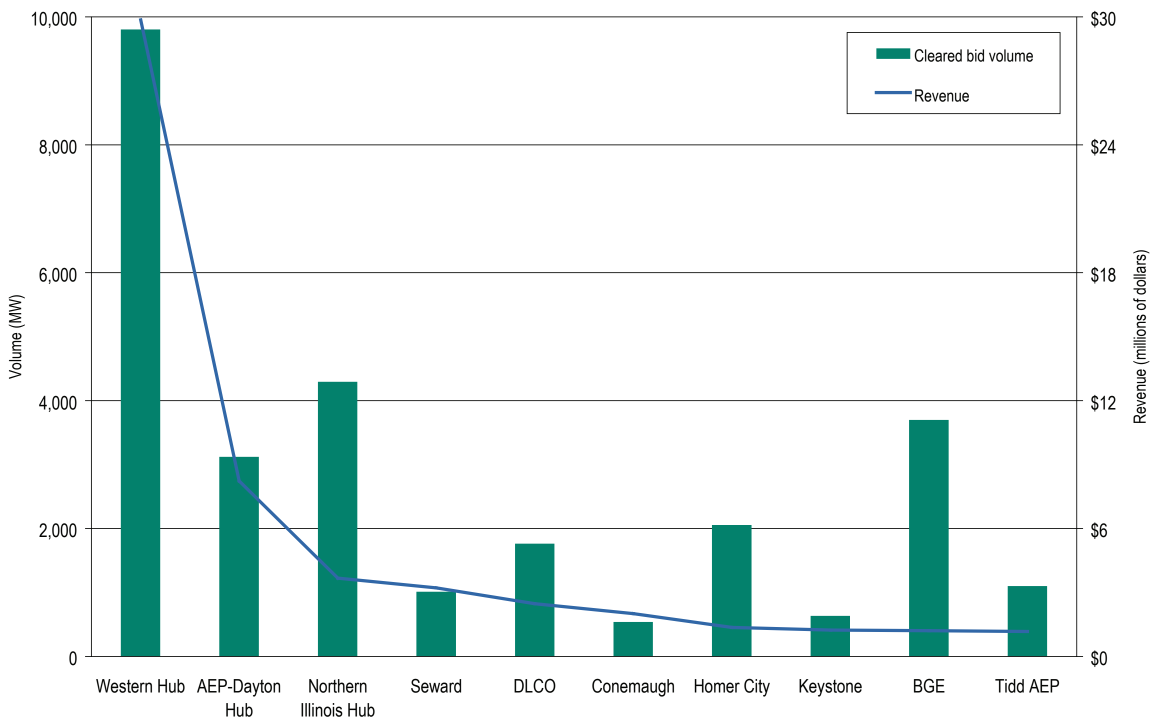
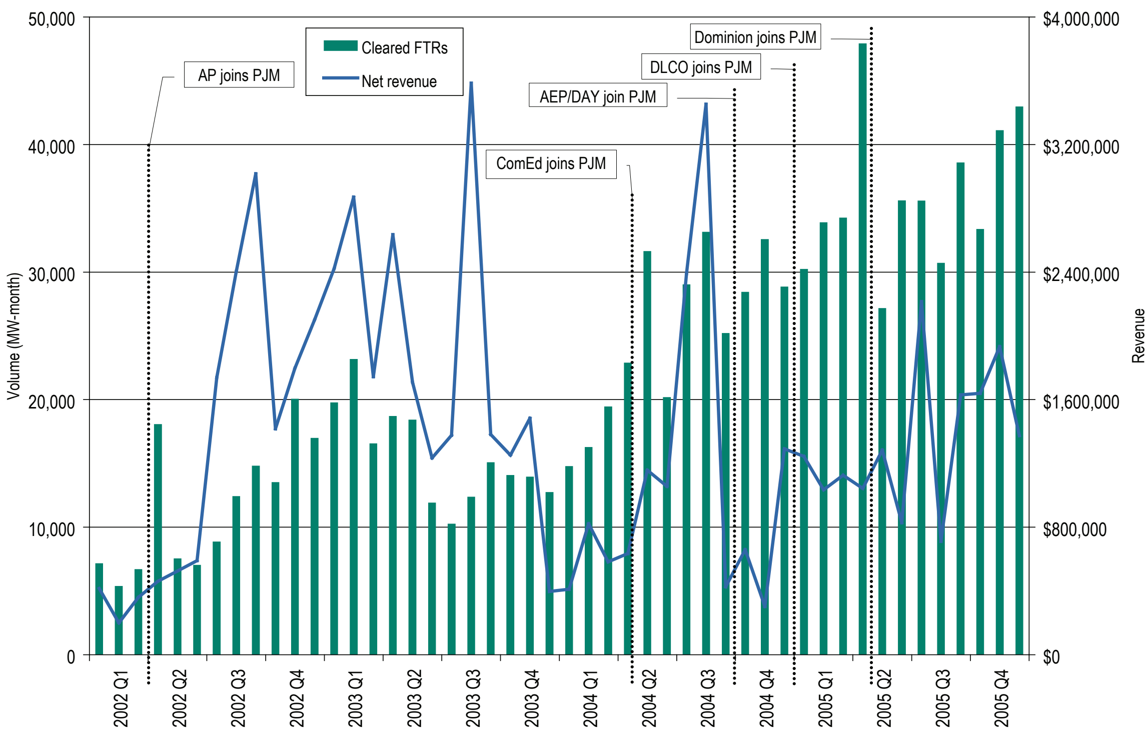


Figure 8-7 depicts the total cleared volume together with the total auction revenue generated in Monthly FTR Auctions during calendar years 2002 through 2005. Average monthly revenue in 2005 was about $1.3 million per month. The average volume for the period January 1, 2005, through December 31, 2005, was 36,000 MW-month.

Figure 8-7 - Monthly FTR Auction cleared volume and net revenue: Calendar years 2002 to 2005



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. Table 8-7 illustrates how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined. 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.

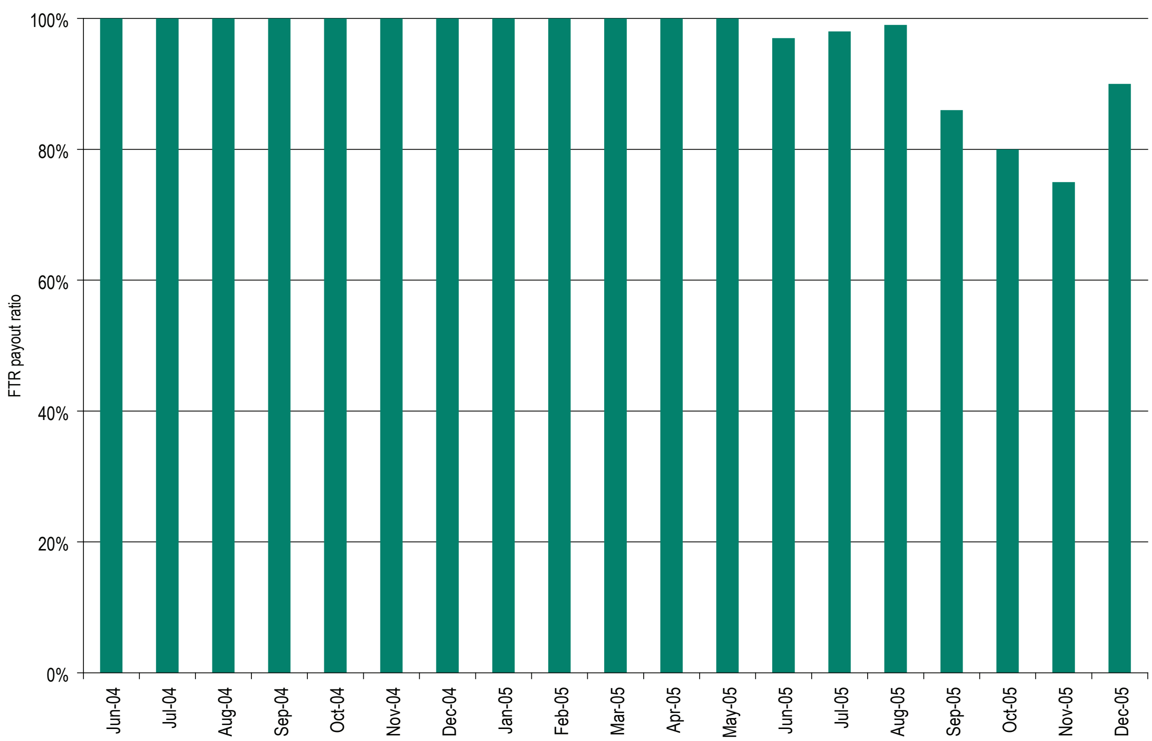
Table 8-7 - Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Congestion Revenue						
Pricing Node	Day-Ahead LMP	Load	Load Payments	Generation	Generation Credits	Transmission Congestion Charges
A	$10	0	$0	100	$1,000	
B	$15	50	$750	0	$0	
C	$20	50	$1,000	100	$2,000	
D	$25	50	$1,250	0	$0	
E	$30	50	$1,500	0	$0	
Total		200	$4,500	200	$3,000	$1,500
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				$2,000	($250)	
Congestion Accounting						
Transmission Congestion Charges						$1,500
+Negative FTR Target Allocations						$250
=Total Congestion Charges						$1,750
Positive FTR Target Allocations				$2,000		
-FTR Congestion Credits				$1,750		
=Congestion Credit Deficiency				$250		
FTR Payout Ratio				0.875		

FTR Revenue and Congestion

FTR target allocations are based on hourly, day-ahead prices for the respective FTR paths and equal the revenue required to hedge FTR holders fully against congestion. 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 2004 through December 2005.[16] FTRs were paid at 100 percent of the target allocations for the 2004 to 2005 planning period. FTRs through December 31, 2005, of the 2005 to 2006 planning period have been paid at 91 percent of the target allocation level.[17]

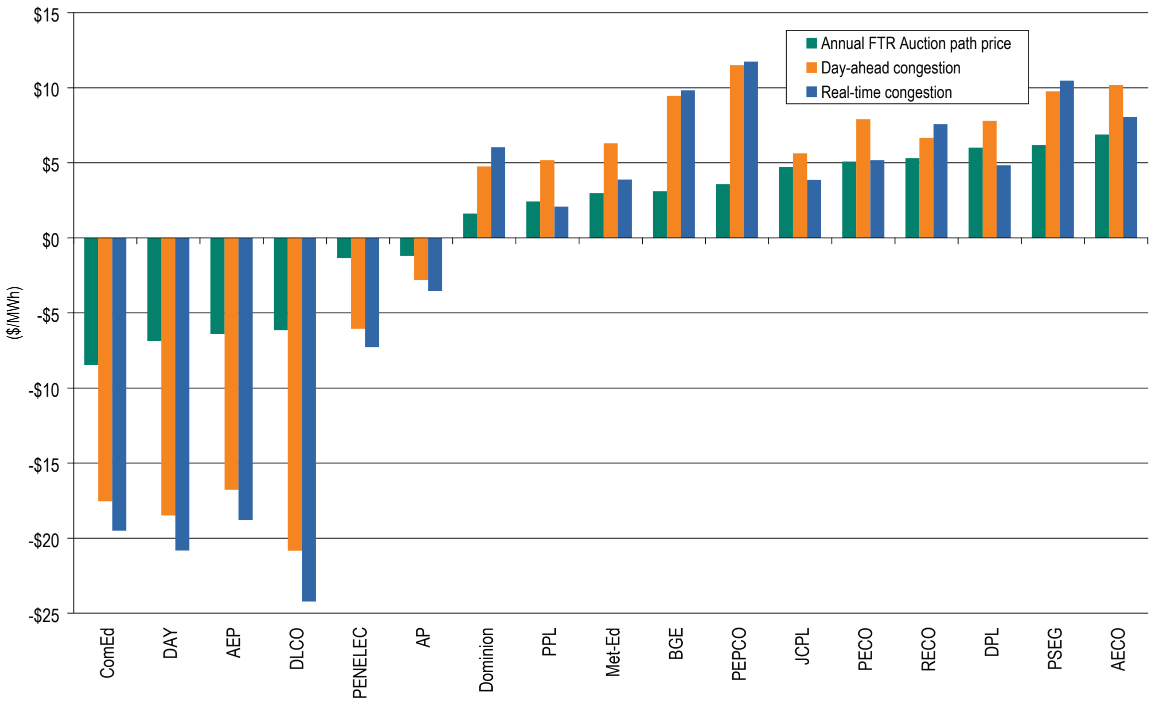
Figure 8-8 - Monthly FTR payout ratio: June 2004 to December 2005



16 See Section 7, “Congestion,” at Table 7-5, “Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period.”
17 For full congestion accounting and FTR revenue adequacy data, see Section 7, “Congestion.”

Figure 8-9 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone with reference to Western Hub prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $5.09 per MWh in the Annual FTR Auction and that about $7.91 per MWh of day-ahead congestion and $5.18 per MWh of real-time congestion existed between the Western Hub and the zone. The data show that congestion costs, approximated in this way, exceeded the cost of FTRs for most zones that are located east of Western Hub while congestion costs and price of FTRs are negative for control zones that are located west of that hub.

Figure 8-9 - Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2005 to 2006 through December 31, 2005



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 2005 to 2006 planning period through December 31, 2005. Figure 8-10 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 84.4 percent of total positive target allocations. FTRs with the top three sinks, the AEP, AP and Dominion Control Zones, included 63.4 percent of all positive target allocations. The top 10 sinks that created liability accounted for 43.4 percent of total negative target allocations. FTRs with the Western Hub as the sink encompassed 11.6 percent of all negative target allocations.

Figure 8-10 - Ten largest positive and negative FTR target allocations summed by sink: Planning period 2005 to 2006 through December 31, 2005

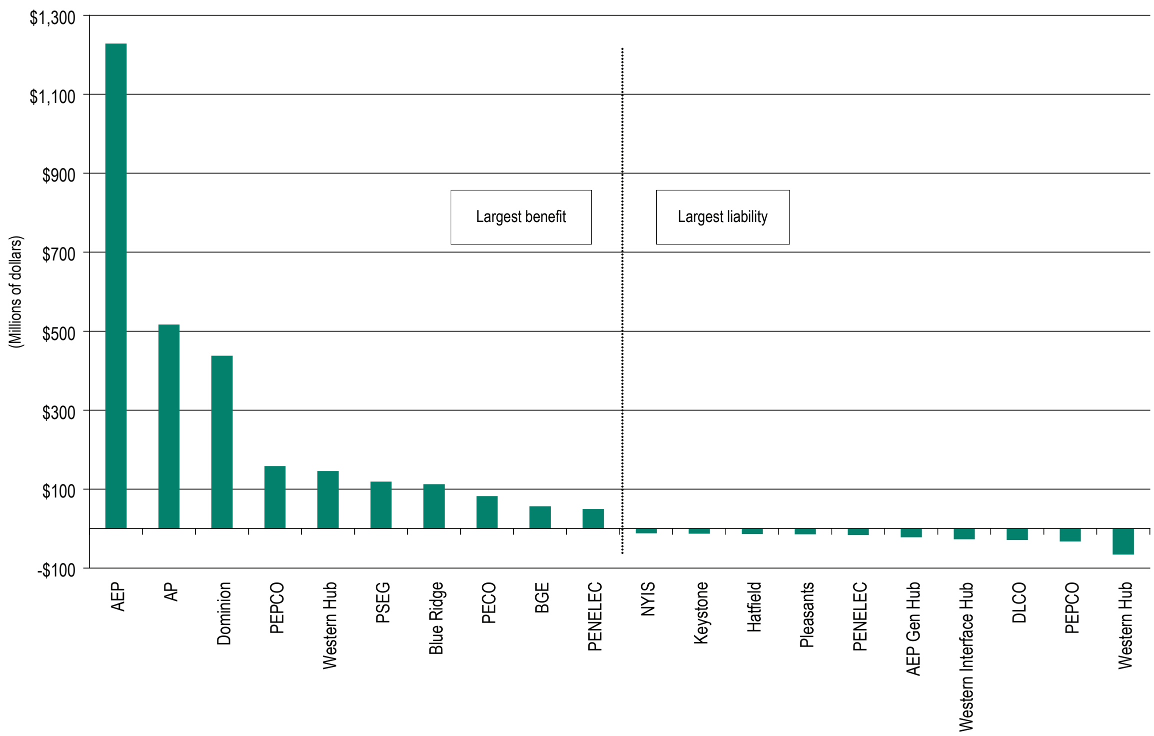
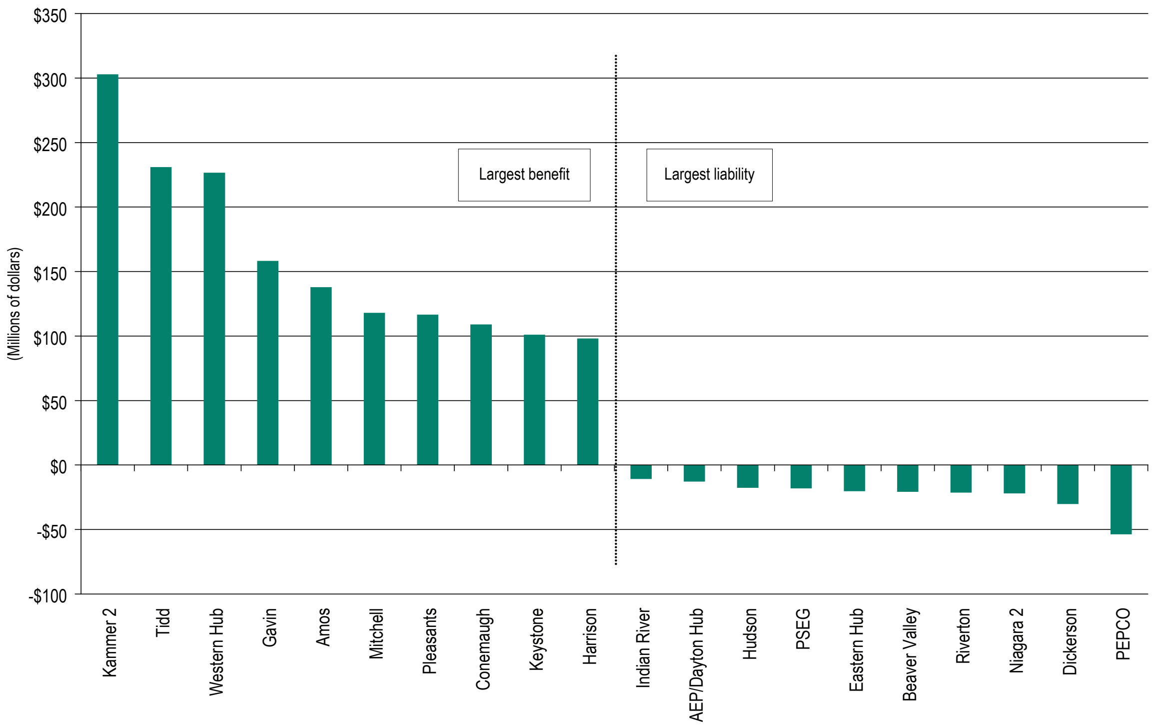


Figure 8-11 shows the FTR sources with the largest positive and negative target allocations. The top 10 sources with a positive target allocation accounted for 46.4 percent of total positive target allocations. All of these 10 sources were located in the AP and AEP Control Zones. FTRs with the Kammer 2 unit as their source included 8.8 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 40.4 percent of total negative target allocations. FTRs with the PEPCO Control Zone as the source encompassed 9.5 percent of all negative target allocations.

Figure 8-11 - Ten largest positive and negative FTR target allocations summed by source: Planning period 2005 to 2006 through December 31, 2005



Auction Revenue Rights

ARRs are financial instruments that entitle their holders to receive revenue or pay charges based on prices in the Annual FTR Auction. The ARR target allocation (i.e., what the ARR holder should receive) 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 FTR Auction revenue, ARR holders are granted credits 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 and AP Control Zone. For the 2005 to 2006 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the new ComEd, AEP, DAY, DLCO and Dominion Control

Zones. After their integration dates, market participants in the new 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 zones, directly allocated FTRs with positive economic value follow the load.[18]

Market Structure

Supply and Demand

Since ARRs are financial instruments allocated annually to network and long-term, firm point-to-point transmission customers, the maximum ARR demand equals the subscribed amount of such services. As of June 1, 2005, PJM had projected that its 2005 network peak load would be 126,293 MW plus an additional 6,066 MW of firm point-to-point service. Therefore, maximum ARR demand, including direct allocation FTRs for newly integrated control zones, was expected to be 132,359 MW, the sum of network and long-term, firm point-to-point transmission service.

ARR demand was 82,343 MW during the 2005 to 2006 planning period, up from 55,128 MW during the 2004 to 2005 planning period. Demand for ARRs increased because of load growth and the eligibility of the newly integrated zones to select ARR allocations, instead of direct allocation FTRs.

PJM's Open Access Transmission Tariff specifies the types of transmission service that are available to eligible customers. Eligible customers submit requests for transmission service – network and firm, point-to-point service – to PJM through the Open Access Same-Time Information System (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 network system. All available generating resources are included when evaluating the requested transmission services. Theoretically, since total eligible ARR demand for the system cannot exceed the combined MW of network and firm, point-to-point services, 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.

For the 2005 to 2006 planning period, 59,410 MW of ARRs were cleared and allocated out of all the ARR requested, leaving uncleared bids of 22,933 MW. The Cedar Grove - Clifton 230 kV line and the Laurel - Woodstown 69 kV line were the principal constraints limiting supply in the Stage 1 ARR allocation. Similarly, the AP South Interface, the Branchburg 500/230 kV transformer and the Eastern Interface were the principal constraints limiting supply in the Stage 2 ARR allocation.

In response to a 2004 order by the United States Federal Energy Regulatory Commission (FERC),[19] 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. In a March 7, 2005,

18 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Reassignment of Financial Transmission Rights (FTRs)," Section 5, p. 32.
19 106 FERC ¶ 61,049 (2004).

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.[20] The rules were approved before the start of its Stage 1 ARR allocation process and became effective with the 2005 to 2006 planning period.

When retail load switches among LSEs, existing PJM market rules ensure that ARRs and their associated revenues are automatically reassigned from the losing to the winning LSE if the losing LSE has a net positive economic ARR value to that zone. About 10,921 MW of ARRs associated with $169,200 per MW-day of revenue were automatically reassigned in the first seven months (June 1 to December 31) of the 2005 to 2006 planning period. About 22,752 MW of ARRs with $173,600 per MW-day of revenue were reassigned for the 2004 to 2005 planning period. Any MW of load may be reassigned multiple times over a period. However, when ARRs are self-scheduled, the underlying FTR does not follow load and this may diminish the value of the hedge.

Prior to the start of the Stage 2 ARR allocation process, a participant can relinquish any portion of the ARR awards resulting from Stage 1 allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[21] Immediately after the Stage 1 ARR allocation for the 2005 to 2006 planning period, eligible customers relinquished 270 MW of the allocated ARRs. Participants may seek additional ARRs in the Stage 2 allocation.

For the set of requested ARRs, available supply was 59,410 MW. This level of ARR availability was higher than the 33,589 MW available during the 2004 to 2005 planning period, but still left 22,933 MW of ARR demand unfulfilled. The Cedar Grove - Clifton 230 kV and the Laurel - Woodstown 69 kV lines were the principal binding constraints limiting supply in the Stage 1 ARR allocation. Similarly, the AP South Interface, the Branchburg 500/230 kV transformer and the Eastern Interface were the principal binding constraints limiting supply in the Stage 2 ARR allocation.

ARR Allocation

Network service and long-term, firm point-to-point transmission customers can request ARRs up to the amount of their transmission service.[22] 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.[23, 24]

20 110 FERC ¶ 61,254 (2005).

21 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Annual Allocation of Auction Revenue Rights (ARRs) – Stage 1," Section 4, p. 24.

22 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.

23 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.

24 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Annual Allocation of Auction Revenue Rights (ARRs) – Stage 1," Section 4, p. 22.

PJM allocates annual ARRs to eligible customers in a two-stage process, where the first stage is one round and 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 transmission zone or load aggregation zone.[25] 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 transmission zone or load aggregation zone to 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.

If the requested set of ARRs is not simultaneously feasible,[26] customers are allocated *pro rata* shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints as follows:

Individual *pro rata* MW = (Constraint capability) * (Individual requested MW / Total requested MW) * (1 / per MW effect on line)[27]

External capacity resources must have a confirmed transmission service request in OASIS prior to the annual ARR allocation. If firm transmission service is used to deliver external capacity into PJM and the capacity resource is located in a control zone that joins PJM, the firm point-to-point transmission service may be converted to network service after control zone integration.

Market participants constructing transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability.[28] 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.

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 OASIS.[29]

25 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Network Integration Service Auction Revenue Rights (ARRs)," Section 3, p. 18.
26 The simultaneous feasibility test (SFT) ensures that the approved set of ARRs can be supported by the transmission system and is meant to ensure ARR revenue adequacy.
27 See Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.
28 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Allocation of Incremental Auction Revenue Rights (ARRs)," Section 4, p. 27.
29 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Firm Point-to-Point Transmission Auction Revenue Rights (ARRs)," Section 3, p. 19.

ARR Reassignment for Retail Load Switching

Current PJM rules ensure that when load switches among LSEs during the planning period, a proportional share of associated ARRs within a given transmission or load aggregation zone is automatically reassigned to follow that load.[30] ARR reassignment occurs only if the LSE losing load has ARRs with 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. 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, in the case where an LSE has elected to self-schedule ARRs, the positively valued ARRs follow load but the underlying FTRs do not.

Table 8-8 - ARRs automatically reassigned for network load changes by control zone (MW-day): June 1, 2004, to December 31, 2005

	2004/2005 (12 Months)	2005/2006 (7 Months)*
AECO	181	491
AEP	94	213
AP	188	181
BGE	4,383	2,608
ComEd	3,288	2,390
DAY	48	3
DLCO	364	467
Dominion	0	74
DPL	2,461	112
JCPL	784	1,000
Met-Ed	108	79
PECO	830	346
PENELEC	73	77
PEPCO	8,507	2,030
PPL	219	55
PSEG	1,206	791
RECO	18	4
Total	22,752	10,921

* Through 31-Dec-05

30 "PJM Financial Transmission Rights Manual" (April 15, 2005), "Reassignment of Auction Revenue Rights (ARRs)," Section 4, p. 26.

Table 8-8 and Table 8-9 summarize ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2004 and December 2005. For the first seven months (June 1 to December 31) of the 2005 to 2006 planning period, more than 10,900 MW of ARRs were automatically reassigned, generating about $169,200 per MW-day of revenue.

Table 8-9 - ARR revenue automatically reassigned for network load changes by control zone [Dollars (thousands) per MW-day]: June 1, 2004, to December 31, 2005

	2004/2005 (12 Months)	2005/2006 (7 Months)*
AECO	$4.3	$16.2
AEP	$0.0	$4.9
AP	$0.0	$21.3
BGE	$41.7	$39.4
ComEd	$0.1	$7.9
DAY	$0.0	$0.0
DLCO	$0.0	$3.0
Dominion	$0.0	$0.0
DPL	$34.5	$1.8
JCPL	$10.9	$18.8
Met-Ed	$1.3	$2.2
PECO	$15.3	$13.0
PENELEC	$2.0	$1.6
PEPCO	$29.2	$15.2
PPL	$2.0	$1.2
PSEG	$32.3	$22.7
RECO	$0.0	$0.0
Total	$173.6	$169.2

* Through 31-Dec-05

ARRs and Integrations

Transitional FTR Allocation

During any planning period when new control zones are being integrated, PJM directly allocates FTRs to eligible customers in those zones.[31] These customers can elect to receive either annual ARRs or direct allocation FTRs at the start of the first two full planning periods of their PJM membership, but do not retain the direct allocation FTR option after the two-year transition period. Table 8-1 summarizes eligibility for ARRs and direct allocation FTRs.

Congestion Mitigation Credits

In response to the March 12, 2003, FERC order addressing direct assignment of FTRs for load in new zones as they are added to PJM,[32] PJM made a compliance filing[33] providing members in newly integrated zones the choice of receiving a direct allocation of FTRs or an allocation of FTRs for the two succeeding Annual FTR Auctions following the integration of the new zone into the PJM Energy Market.

In a related January 28, 2004, order,[34] the FERC required PJM to amend its tariff and file its proposed allocation method under section 205 of the Federal Power Act (FPA). The FERC also required that, if PJM could not award FTRs to all existing firm point-to-point customers, it would have to justify why the resulting allocation was reasonable and why mitigating measures should not be adopted.

The FERC found that since the allocation process gave preference to network service customers, PJM's annual allocation process for FTRs and ARRs under its existing Tariff and Operating Agreement appeared to be unjust and unreasonable under section 206 of FPA and instituted procedures to determine a just and reasonable allocation process for succeeding years.[35]

In responding, PJM acknowledged that its two-stage allocation process included a preference for native load customers served from resources that had historically served their load.[36]

PJM submitted a January 7, 2005, filing[37] in which PJM proposed to permit firm point-to-point customers to obtain FTRs/ARRs on a comparable basis to network customers for historic resources in the first stage of the allocation. After clarification on March 7, 2005, order and subsequent clarification on May 9, 2005, the FERC accepted PJM's proposal that permits point-to-point customers to obtain FTRs/ARRs on a comparable basis to network customers for nonhistoric resources in the second stage of the allocation.

The FERC ordered that if long-term, firm point-to-point transmission customers in the ComEd and AEP Control Zones were not allocated their full ARRs or FTR requests that they be provided with congestion mitigation outside of the FTR and ARR markets. PJM implemented this order by offering mitigation credits equal to FTR payments to those eligible customers that had not received their requested allocation.

31 "PJM Financial Transmission Rights Manual" (April 15, 2005), "FTR Allocation Process for New Load in Zones Associated with Market Growth," Section 5, p. 29.
32 102 FERC ¶ 61,276 (2003).
33 *PJM Interconnection, L.L.C.*, Compliance Filing, Docket No. ER03-406-002 (April 11, 2003, amended April 22, 2003).
34 106 FERC ¶ 61,049 (2004).
35 107 FERC ¶ 61,223 (2004) at P 47.
36 *Id* at P 15.
37 *PJM Interconnection, L.L.C.,* Compliance Filing, Docket Nos. ER04-742-003 and EL04-105-001 (January 7, 2005).

Total credit costs for these unallocated ARRs or FTRs are assessed as uplift charges. All firm network and point-to-point transmission service customers with ARRs, FTRs or congestion mitigation credits within the ComEd and AEP Control Zones pay these zonal uplift charges.

For the portions of the 2004 to 2005 planning period, Table 8-10 summarizes FTRs requested by and awarded to customers in the relevant control zones, including mitigation FTRs.

Table 8-10 - ComEd and AEP Control Zones FTR mitigation credits: Planning period 2004 to 2005

	FTR Requested (MW)	FTR Awarded (MW)	FTR Unallocated (MW)	Requested FTR as Percent Unallocated
ComEd	476	308	168	35%
AEP	1,005	51	954	95%
Total	1,481	359	1,122	76%

Congestion mitigation credits for the ComEd and AEP Control Zones were valid only for the 2004 to 2005 planning period's FTR Market, ending May 31, 2005. During the 2005 to 2006 planning period, no mitigation credit is required for these integrated zones 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.

Pursuant to section 205 of the FPA, PJM's September 1, 2004, compliance filing with the FERC proposed an initial allocation of FTRs for the Dominion Control Zone, starting from its then planned November 1, 2004, integration date.[38] The FERC order found that under PJM's allocation, 100 percent of all FTRs requested for the Dominion Control Zone in Stage 1 were awarded.[39] Similarly, in the Stage 2 allocation, no ARRs requested by firm point-to-point transmission service customers had to be prorated. Thus, unlike the FTR allocation process for the ComEd and AEP Control Zones, the FERC agreed with PJM that no mitigation was necessary in this case.[40]

According to the FERC order mentioned above, a mechanism for congestion mitigation credit for Dominion Control Zone was not required.

ARR Performance

Volume

Of 82,343 MW in ARR requests for the 2005 to 2006 planning period, 59,410 MW (72 percent) were allocated. Eligible market participants subsequently converted 32,631 MW of these allocated ARRs into annual FTRs (55 percent of total allocated ARRs), leaving 26,779 MW of ARRs outstanding. Of 55,128 MW in ARR requests for the 2004 to 2005 planning period, 33,589 MW (61 percent) were allocated, of which 13,061 or 39 percent were converted into FTRs.

38 Dominion joined PJM on May 1, 2005.

39 The FERC notes that according to PJM, the only FTR requests that were prorated in this allocation were from two network service users that sought additional FTRs to resources that were perceived to have higher value [109 FERC ¶ 61,075 (2004) at P 17].

40 109 FERC ¶ 61,075 (2004) at P 17.

Revenue

Any ARR credits received equal the product of the ARR MW and the sink-minus-source price difference for the ARR path from the Annual FTR Auction. The degree to which ARR credits provide a complete congestion hedge is determined by the prices that result from the Annual FTR 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. The resultant ARR credit could be greater than, less than, or equal to the actual congestion that occurs on the selected path in the Day-Ahead Energy Market and thus could provide a hedge with varying levels of completeness.

Eligible customers can also opt to retain the underlying FTRs linked to their ARRs through a process termed self-scheduling. The underlying FTR[41] has a hedge value based on actual day-ahead congestion on the selected path rather than a hedge value based on what bidders pay in the Annual FTR Auction.

ARR holders will receive $870 million in credits from the Annual FTR Auction during the 2005 to 2006 planning period, with an average hourly ARR credit of $1.67 per MWh. During the comparable 2004 to 2005 planning period, ARR holders received $345 million in ARR credits, with an average hourly ARR credit of $1.17 per MWh.

Revenue Adequacy

An ARR target allocation defines revenue that an ARR holder should receive and is equal to the product of ARR MW and the price differences between ARR sink and source established during the Annual FTR Auction. FTR Auction revenue is the net revenue from the auction. All ARR holders receive ARR credits equal to their target allocations if total net Annual and Monthly FTR Auction revenues are greater than, or equal to, the sum of all ARR target allocations. If the combined net Annual and Monthly FTR Auction revenues are less than that, the available revenue is proportionally allocated among all ARR holders.

Table 8-11 lists ARR target allocations and net revenue sources from the Annual and Monthly FTR Auctions for the 2003 to 2004, the 2004 to 2005 and the 2005 to 2006 (through December 31, 2005) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for all three planning periods. The 2005 to 2006 planning period's Annual and Monthly FTR Auctions generated a surplus of $22 million in auction net revenue through December 31, 2005, above the amount needed to pay 100 percent of ARR target allocations.

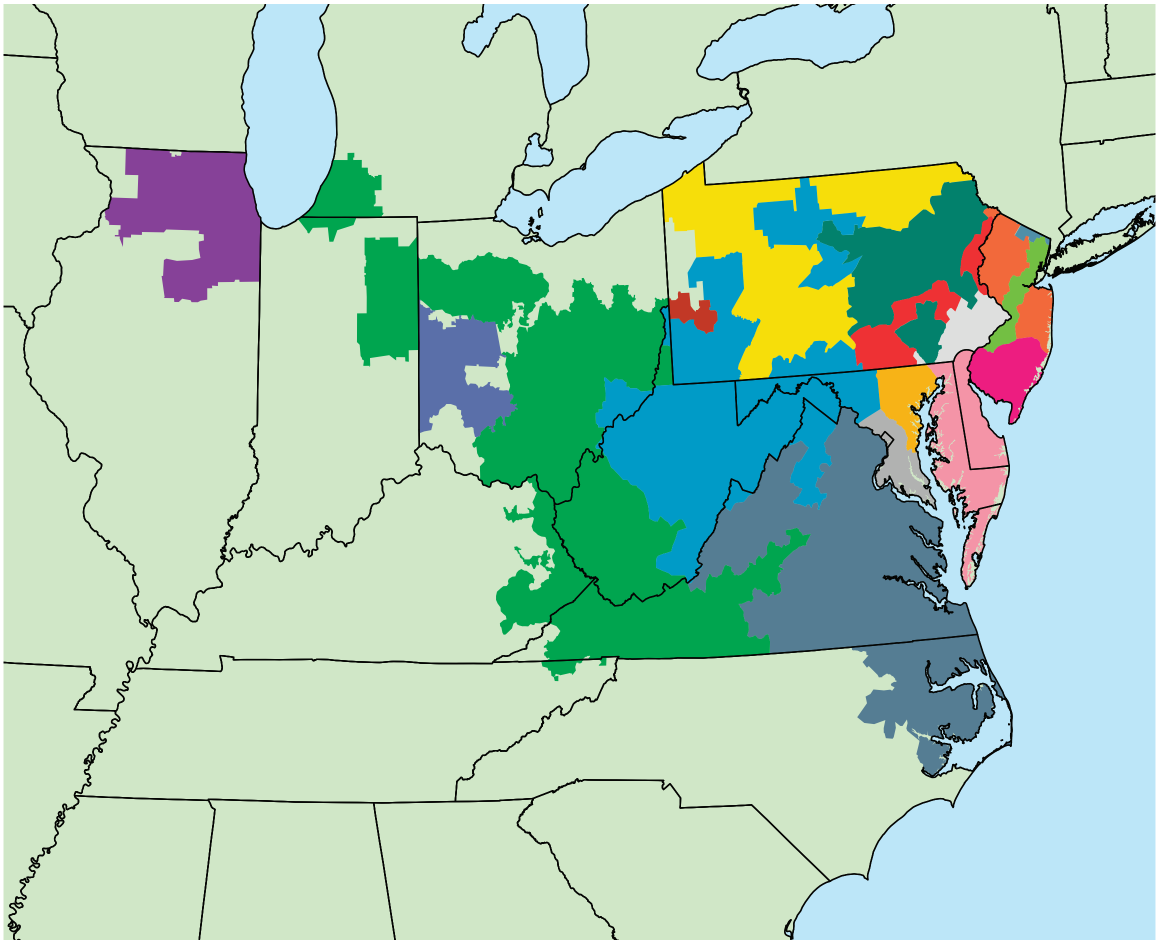
Table 8-11 - ARR revenue adequacy [Dollars (millions)]: By planning period

	2003/2004	2004/2005	2005/2006
Total FTR Auction Net Revenue	$359	$385	$892
Annual FTR Auction Net Revenue	$333	$370	$882
Monthly FTR Auction Net Revenue*	$26	$15	$10
ARR Target Allocations	$311	$345	$870
ARR Credits	$311	$345	$870
Surplus Auction Revenue	$48	$40	$22
ARR Payout Ratio	100%	100%	100%

* Shows 17 months for 2003/2004, 12 months for 2004/2005 and 7 months ending 31-Dec-05 for 2005/2006

41 FTR value is determined each hour in the Day-Ahead Energy Market as the product of the FTR MW and the FTR sink-minus-source price difference from the Day-Ahead Energy Market.

APPENDIX A – PJM SERVICE TERRITORY



Legend

ZONE

- Allegheny Power Systems
- American Electric Power Co., Inc
- Atlantic Electric Company
- Baltimore Gas and Electric Company
- ComEd
- Dayton Power and Light Company
- Delmarva Power and Light
- Dominion
- Duquesne Light
- Jersey Central Power and Light Company
- Metropolitan Edison Company
- PPL Electric Utilities
- PECO Energy
- Pennsylvania Electric Company
- Potomac Electric Power Company
- Public Service Electric and Gas Company
- Rockland Electric Company

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 PJM ISO status
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	First PJM Emergency and Economic Load-Response Programs
2002	April	Integration of the AP Control Zone into PJM Western Region
	June	Second PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of full PJM RTO status
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

APPENDIX C – ENERGY MARKET

Frequency Distribution of LMP

Figure C-1, Figure C-2, Figure C-3, Figure C-4, Figure C-5, Figure C-6, Figure C-7 and Figure C-8 provide frequency distributions of real-time locational marginal price (LMP), by hour, for the calendar years 1998 through 2005.[1] The figures show the number of hours (frequency), the cumulative number of hours (cumulative frequency), the percent of hours (percent) and the cumulative percent of hours (cumulative percent) that LMP was within a given, $10-price interval, or for the cumulative columns, within the interval plus all the lower price intervals.[2]

The first six figures show that during the period 1998 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 22.0 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 (0.40 percent of the hours) in 2005.

Frequency Distribution of Load

Figure C-9, Figure C-10, Figure C-11, Figure C-12, Figure C-13, Figure C-14, Figure C-15 and Figure C-16 provide the frequency distributions of PJM load by hour, for the calendar years 1998 through 2005. The figures show the number of hours (frequency), the cumulative number of hours (cumulative frequency), the percent of hours (percent) and the cumulative percent of hours (cumulative percent) that the load was within a given, 5,000 MW load interval, or for the cumulative columns, within the interval plus all the lower load intervals. The integrations of the Allegheny Power Company (AP) Control Zone during 2002, of the Commonwealth Edison Company (ComEd), the American Electric Power Company (AEP) and The Dayton Power & Light Company (DAY) Control Zones during 2004 and of the Duquesne Light Company (DLCO) and Dominion Control Zones during 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[3]

For the years 1998 and 1999, the most frequently occurring load interval was 25,000 MW to 30,000 MW at 35.0 percent and 33.6 percent of the hours, respectively. For the years 2000 and 2001, the most frequently occurring load interval was 30,000 MW to 35,000 MW at 33.9 percent and 34.6 percent of the hours, respectively. 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.

1 LMP was instituted in PJM in April 1998. Before then, there had been a single system price, the market-clearing price (MCP).

2 Only positive LMP intervals are included in these figures.

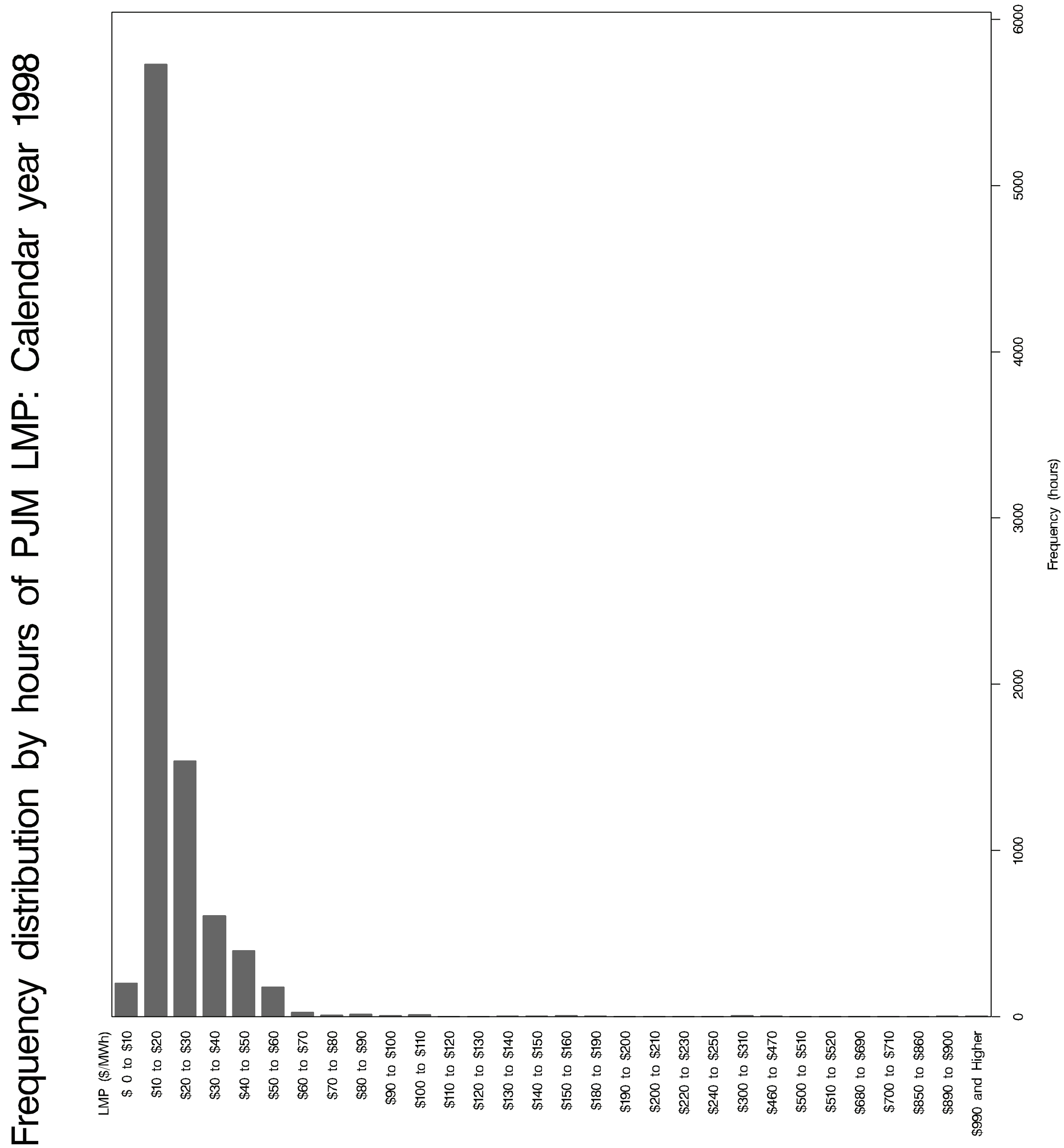
3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all five phases. The only exception is ComEd which is called the ComEd Control Area during Phase 2 of 2004 only.

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.

The summer peak reflected both the Phase 4 integration of the DLCO Control Zone and the Phase 5 integration of the Dominion Control Zone. The peak demand for the year was 133,763 MW and occurred on July 26, 2005.

Figure C-1 - Frequency distribution by hours of PJM LMP: Calendar year 1998



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	203	203	2.32	2.32
$10 to $20	5729	5932	65.41	67.72
$20 to $30	1539	7471	17.57	85.30
$30 to $40	607	8078	6.93	92.23
$40 to $50	396	8474	4.52	96.75
$50 to $60	178	8652	2.03	98.78
$60 to $70	27	8679	0.31	99.09
$70 to $80	10	8689	0.11	99.20
$80 to $90	15	8704	0.17	99.37
$90 to $100	6	8710	0.07	99.44
$100 to $110	11	8721	0.13	99.57
$110 to $120	1	8722	0.01	99.58
$120 to $130	1	8723	0.01	99.59
$130 to $140	4	8727	0.05	99.63
$140 to $150	3	8730	0.03	99.67
$150 to $160	6	8736	0.07	99.74
$180 to $190	2	8738	0.02	99.76
$190 to $200	1	8739	0.01	99.77
$200 to $210	1	8740	0.01	99.78
$220 to $230	1	8741	0.01	99.79
$240 to $250	1	8742	0.01	99.81
$300 to $310	5	8747	0.06	99.86
$460 to $470	2	8749	0.02	99.89
$500 to $510	1	8750	0.01	99.90
$510 to $520	1	8751	0.01	99.91
$680 to $690	1	8752	0.01	99.92
$700 to $710	1	8753	0.01	99.93
$850 to $860	1	8754	0.01	99.94
$890 to $900	3	8757	0.03	99.98
$990 and Higher	2	8759	0.02	100.00

Figure C-2 - Frequency distribution by hours of PJM LMP: Calendar year 1999

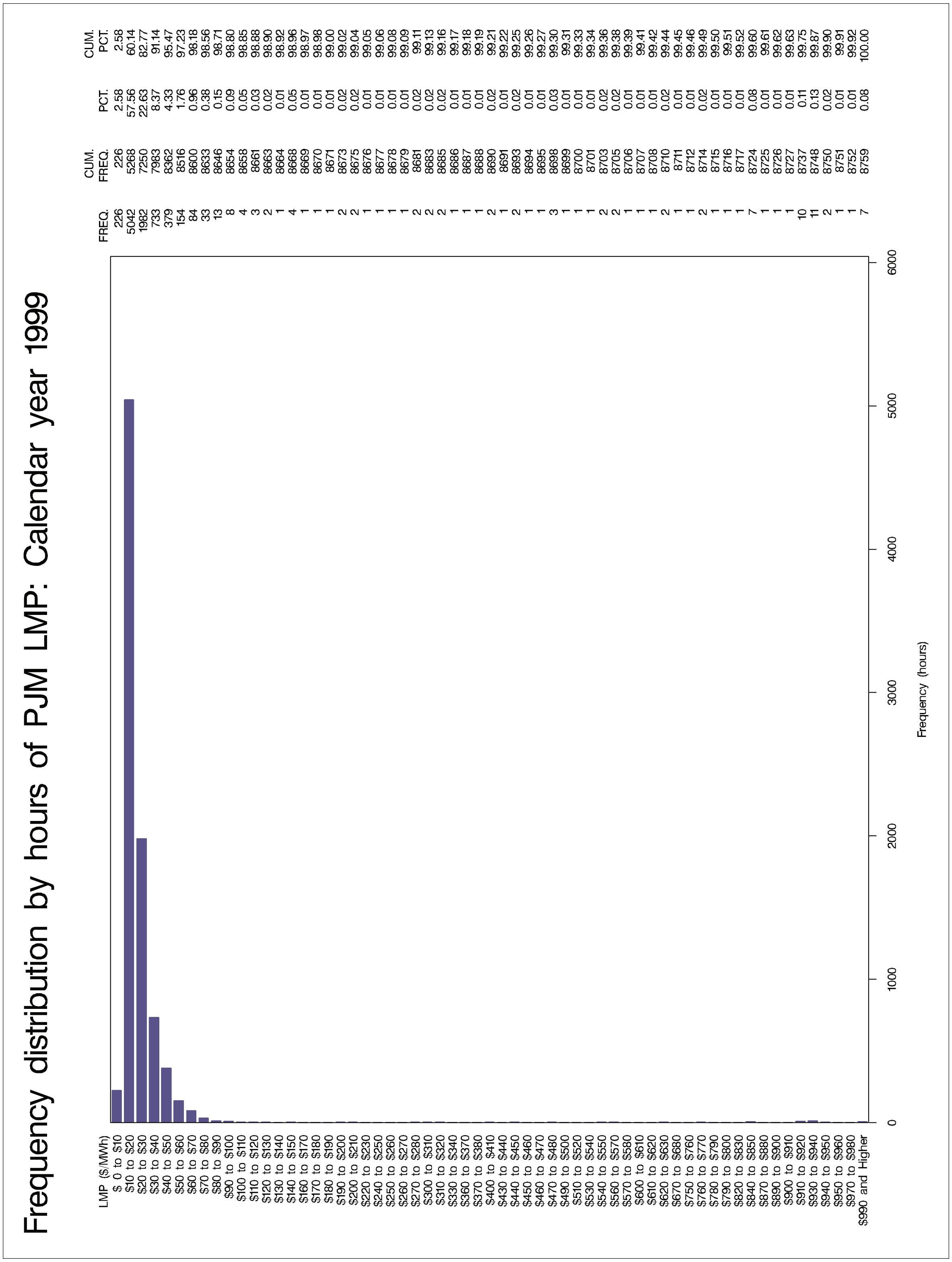
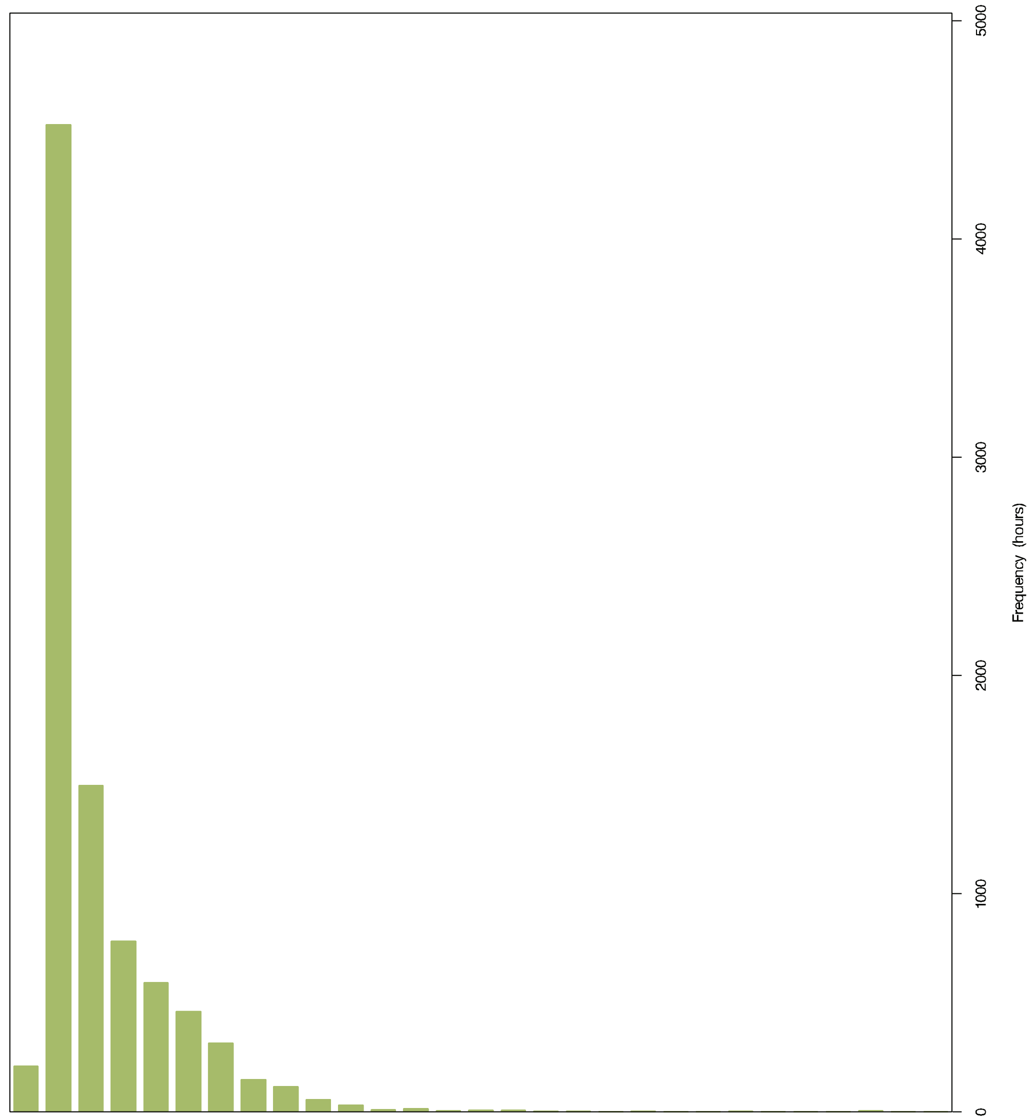


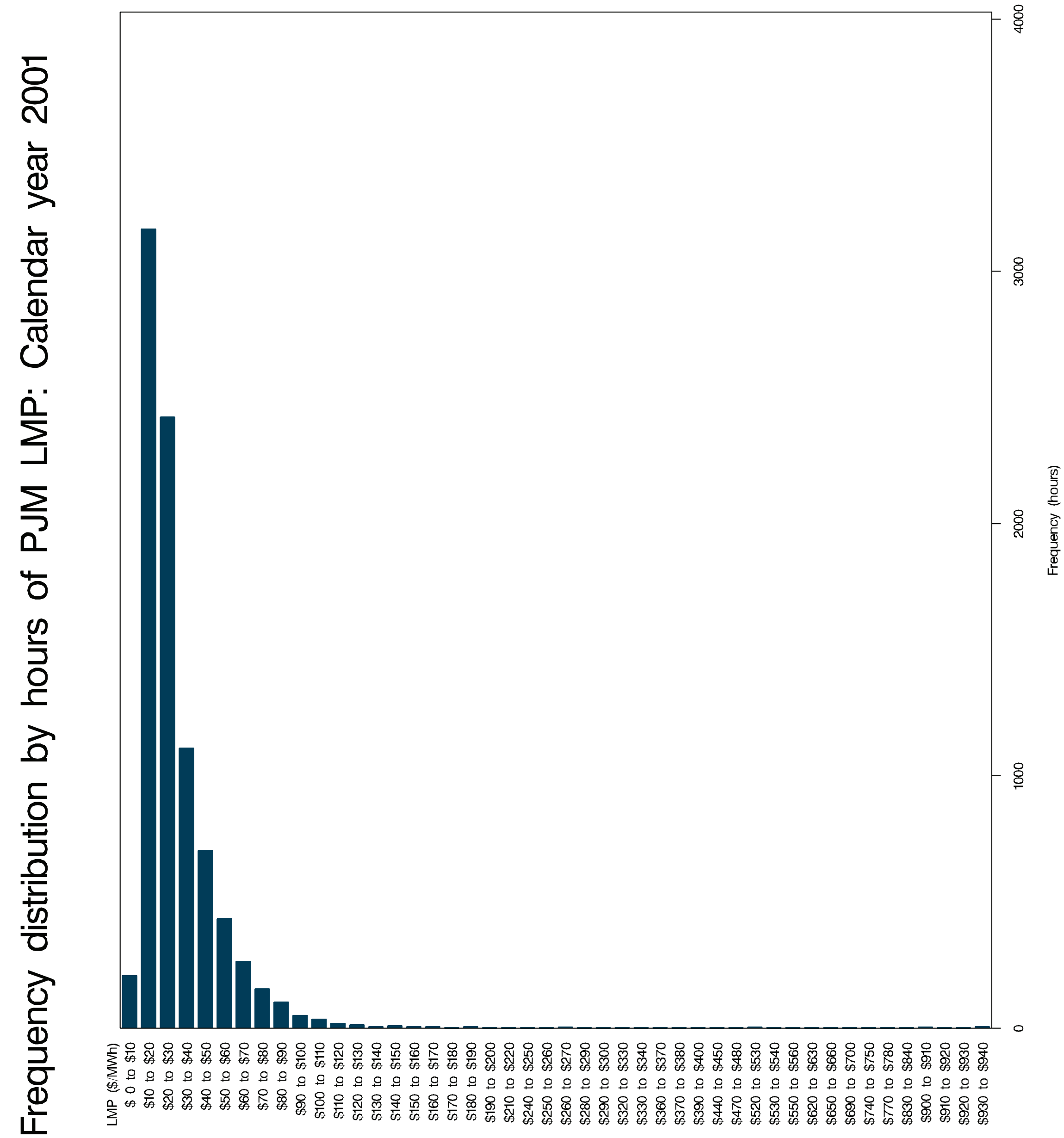
Figure C-3 - Frequency distribution by hours of PJM LMP: Calendar year 2000

Frequency distribution by hours of PJM LMP: Calendar year 2000



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	209	209	2.38	2.38
$10 to $20	4522	4731	51.49	53.87
$20 to $30	1494	6225	17.01	70.88
$30 to $40	782	7007	8.90	79.78
$40 to $50	591	7598	6.73	86.51
$50 to $60	459	8057	5.23	91.73
$60 to $70	315	8372	3.59	95.32
$70 to $80	147	8519	1.67	96.99
$80 to $90	115	8634	1.31	98.30
$90 to $100	56	8690	0.64	98.94
$100 to $110	31	8721	0.35	99.29
$110 to $120	9	8730	0.10	99.40
$120 to $130	13	8743	0.15	99.54
$130 to $140	5	8748	0.06	99.60
$140 to $150	8	8756	0.09	99.69
$150 to $160	6	8762	0.07	99.76
$160 to $170	3	8765	0.03	99.80
$170 to $180	2	8767	0.02	99.82
$180 to $190	1	8768	0.01	99.83
$190 to $200	2	8770	0.02	99.85
$210 to $220	1	8771	0.01	99.86
$220 to $230	1	8772	0.01	99.87
$260 to $270	2	8774	0.02	99.90
$280 to $290	1	8775	0.01	99.91
$290 to $300	1	8776	0.01	99.92
$360 to $370	1	8777	0.01	99.93
$480 to $490	4	8781	0.05	99.98
$590 to $600	1	8782	0.01	99.99
$800 to $810	1	8783	0.01	100.00

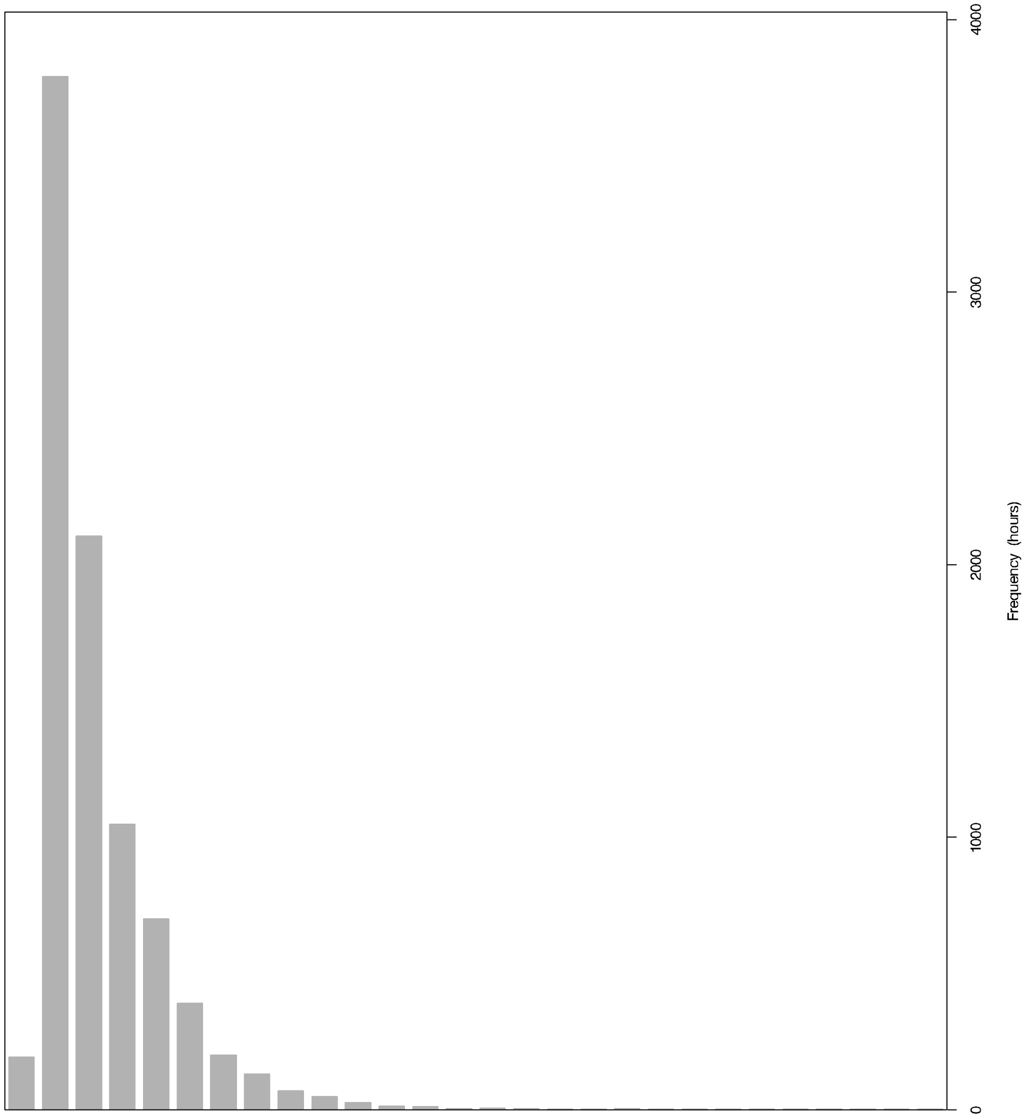
Figure C-4 - Frequency distribution by hours of PJM LMP: Calendar year 2001



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	209	209	2.39	2.39
$10 to $20	3167	3376	36.16	38.54
$20 to $30	2423	5799	27.66	66.21
$30 to $40	1109	6908	12.66	78.87
$40 to $50	704	7612	8.04	86.90
$50 to $60	433	8045	4.94	91.85
$60 to $70	264	8309	3.01	94.86
$70 to $80	155	8464	1.77	96.63
$80 to $90	104	8568	1.19	97.82
$90 to $100	50	8618	0.57	98.39
$100 to $110	36	8654	0.41	98.80
$110 to $120	18	8672	0.21	99.01
$120 to $130	13	8685	0.15	99.16
$130 to $140	5	8690	0.06	99.21
$140 to $150	9	8699	0.10	99.31
$150 to $160	6	8705	0.07	99.38
$160 to $170	6	8711	0.07	99.45
$170 to $180	2	8713	0.02	99.47
$180 to $190	5	8718	0.06	99.53
$190 to $200	1	8719	0.01	99.54
$210 to $220	1	8720	0.01	99.55
$240 to $250	1	8721	0.01	99.57
$250 to $260	1	8722	0.01	99.58
$260 to $270	3	8725	0.03	99.61
$280 to $290	1	8726	0.01	99.62
$290 to $300	1	8727	0.01	99.63
$320 to $330	1	8728	0.01	99.65
$330 to $340	2	8730	0.02	99.67
$360 to $370	1	8731	0.01	99.68
$370 to $380	2	8733	0.02	99.70
$390 to $400	1	8734	0.01	99.71
$440 to $450	1	8735	0.01	99.73
$470 to $480	1	8736	0.01	99.74
$520 to $530	3	8739	0.03	99.77
$530 to $540	1	8740	0.01	99.78
$550 to $560	2	8742	0.02	99.81
$620 to $630	1	8743	0.01	99.82
$650 to $660	2	8745	0.02	99.84
$690 to $700	1	8746	0.01	99.85
$740 to $750	1	8747	0.01	99.86
$770 to $780	1	8748	0.01	99.87
$830 to $840	1	8749	0.01	99.89
$900 to $910	3	8752	0.03	99.92
$910 to $920	1	8753	0.01	99.93
$920 to $930	1	8754	0.01	99.94
$930 to $940	5	8759	0.06	100.00

Figure C-5 - Frequency distribution by hours of PJM LMP: Calendar year 2002

Frequency distribution by hours of PJM LMP: Calendar year 2002



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	194	194	2.21	2.21
$10 to $20	3791	3985	43.28	45.49
$20 to $30	2104	6089	24.02	69.51
$30 to $40	1048	7137	11.96	81.47
$40 to $50	701	7838	8.00	89.47
$50 to $60	391	8229	4.46	93.94
$60 to $70	201	8430	2.29	96.23
$70 to $80	132	8562	1.51	97.74
$80 to $90	69	8631	0.79	98.53
$90 to $100	49	8680	0.56	99.09
$100 to $110	27	8707	0.31	99.39
$110 to $120	13	8720	0.15	99.54
$120 to $130	12	8732	0.14	99.68
$130 to $140	3	8735	0.03	99.71
$140 to $150	5	8740	0.06	99.77
$150 to $160	4	8744	0.05	99.82
$160 to $170	1	8745	0.01	99.83
$170 to $180	1	8746	0.01	99.84
$180 to $190	3	8749	0.03	99.87
$190 to $200	2	8751	0.02	99.90
$200 to $210	1	8752	0.01	99.91
$210 to $220	1	8753	0.01	99.92
$280 to $290	1	8754	0.01	99.93
$290 to $300	1	8755	0.01	99.94
$330 to $340	2	8757	0.02	99.97
$440 to $450	1	8758	0.01	99.98
$580 to $590	1	8759	0.01	99.99
$790 to $800	1	8760	0.01	100.00

Figure C-6 - Frequency distribution by hours of PJM LMP: Calendar year 2003

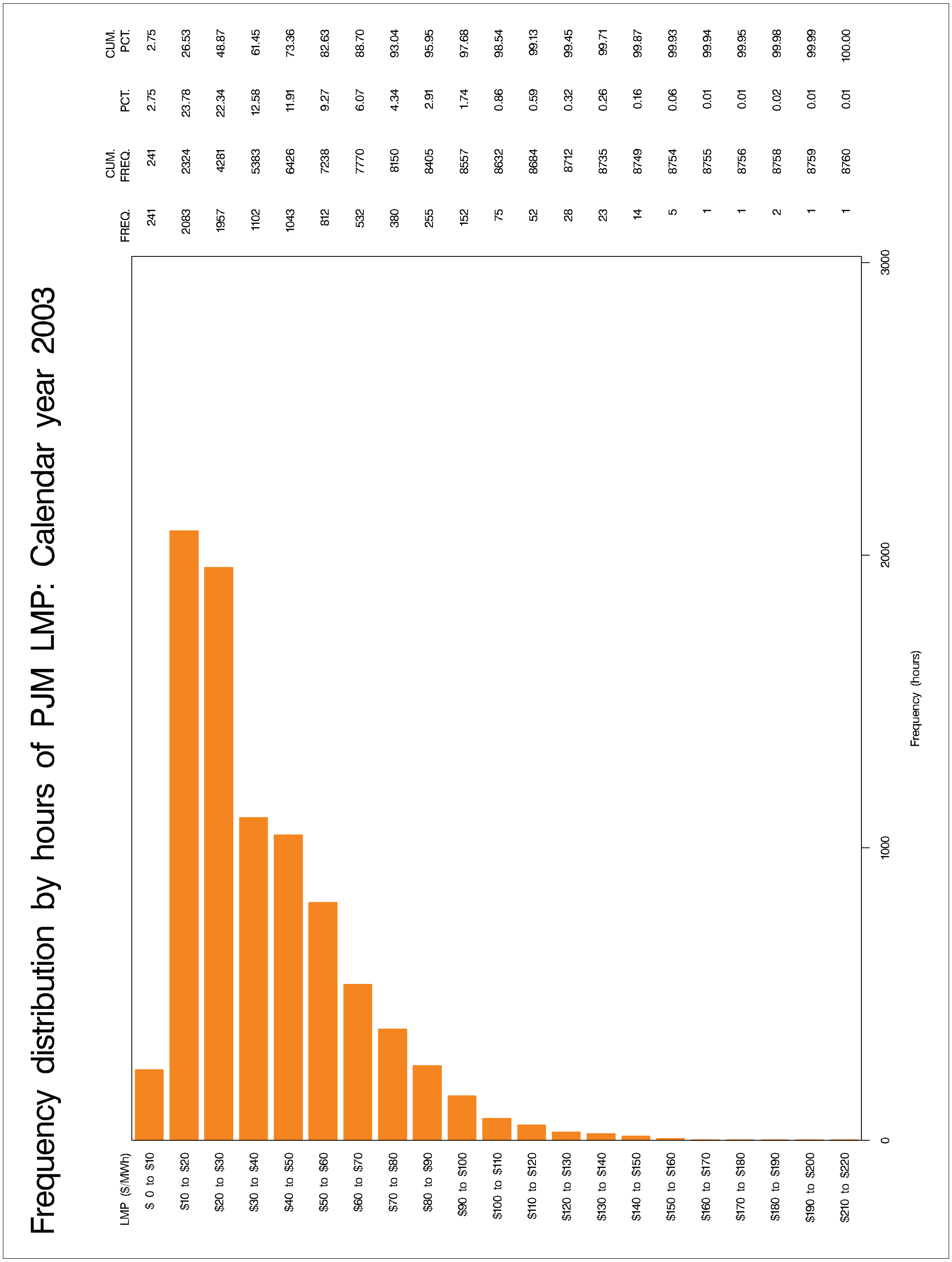
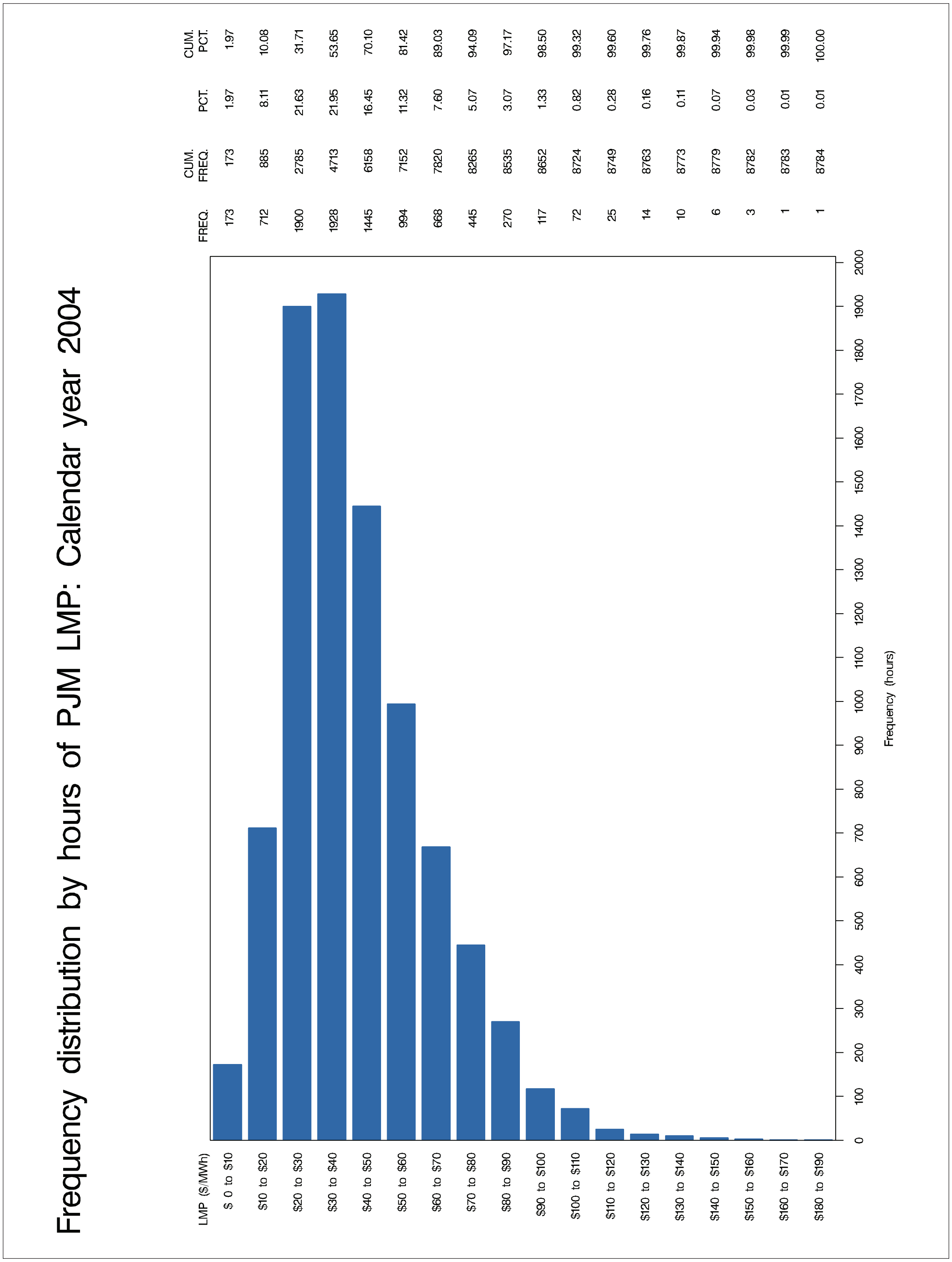
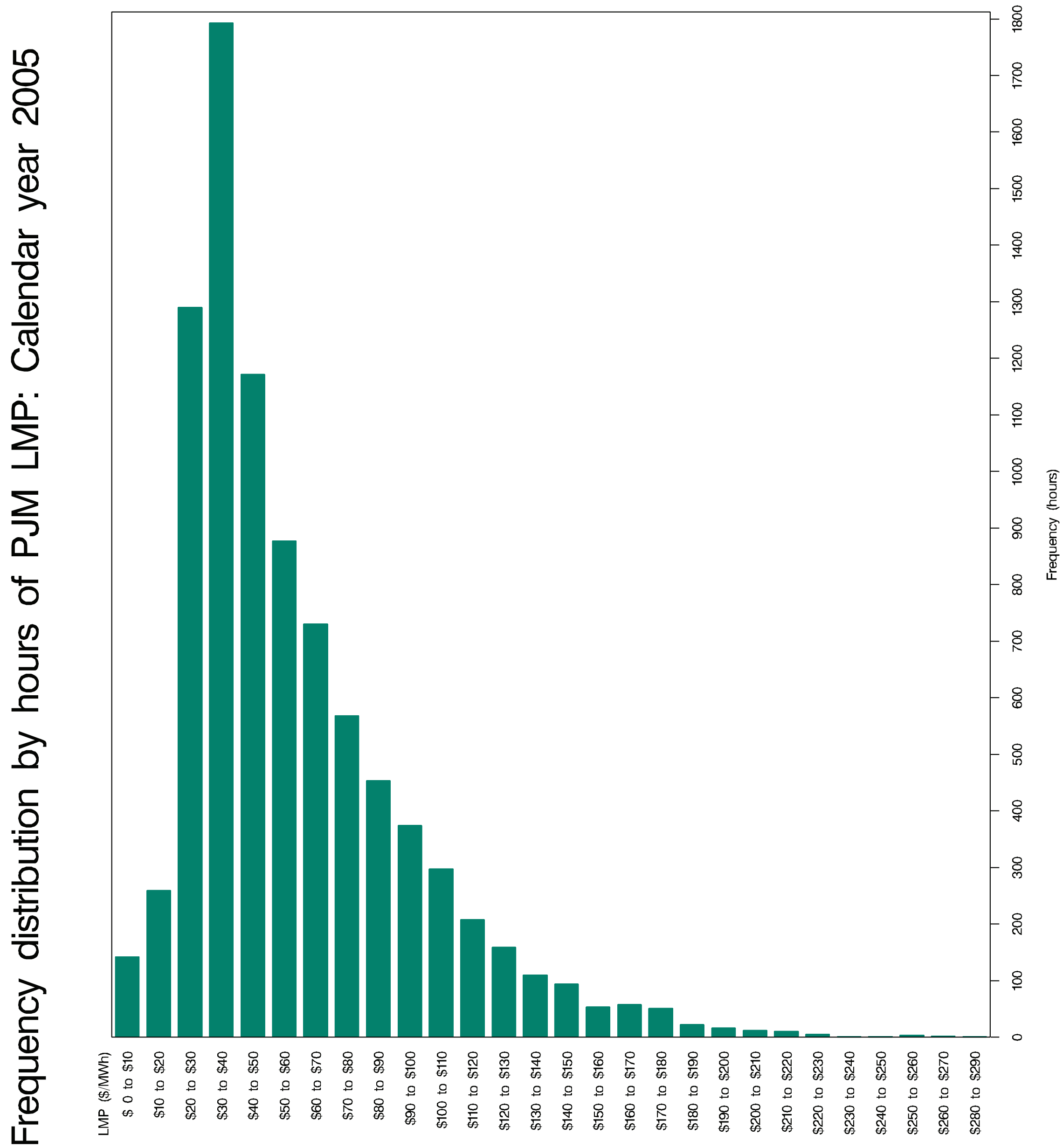


Figure C-7 - Frequency distribution by hours of PJM LMP: Calendar year 2004



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	173	173	1.97	1.97
$10 to $20	712	885	8.11	10.08
$20 to $30	1900	2785	21.63	31.71
$30 to $40	1928	4713	21.95	53.65
$40 to $50	1445	6158	16.45	70.10
$50 to $60	994	7152	11.32	81.42
$60 to $70	668	7820	7.60	89.03
$70 to $80	445	8265	5.07	94.09
$80 to $90	270	8535	3.07	97.17
$90 to $100	117	8652	1.33	98.50
$100 to $110	72	8724	0.82	99.32
$110 to $120	25	8749	0.28	99.60
$120 to $130	14	8763	0.16	99.76
$130 to $140	10	8773	0.11	99.87
$140 to $150	6	8779	0.07	99.94
$150 to $160	3	8782	0.03	99.98
$160 to $170	1	8783	0.01	99.99
$180 to $190	1	8784	0.01	100.00

Figure C-8 - Frequency distribution by hours of PJM LMP: Calendar year 2005



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	142	142	1.62	1.62
$10 to $20	259	401	2.96	4.58
$20 to $30	1290	1691	14.73	19.30
$30 to $40	1793	3484	20.47	39.77
$40 to $50	1172	4656	13.38	53.15
$50 to $60	877	5533	10.01	63.16
$60 to $70	730	6263	8.33	71.50
$70 to $80	568	6831	6.48	77.98
$80 to $90	453	7284	5.17	83.15
$90 to $100	374	7658	4.27	87.42
$100 to $110	297	7955	3.39	90.81
$110 to $120	208	8163	2.37	93.18
$120 to $130	159	8322	1.82	95.00
$130 to $140	110	8432	1.26	96.26
$140 to $150	94	8526	1.07	97.33
$150 to $160	53	8579	0.61	97.93
$160 to $170	57	8636	0.65	98.58
$170 to $180	51	8687	0.58	99.17
$180 to $190	22	8709	0.25	99.42
$190 to $200	16	8725	0.18	99.60
$200 to $210	12	8737	0.14	99.74
$210 to $220	10	8747	0.11	99.85
$220 to $230	5	8752	0.06	99.91
$230 to $240	1	8753	0.01	99.92
$240 to $250	1	8754	0.01	99.93
$250 to $260	3	8757	0.03	99.97
$260 to $270	2	8759	0.02	99.99
$280 to $290	1	8760	0.01	100.00

Figure C-9 - Frequency distribution of hourly PJM load: Calendar year 1998

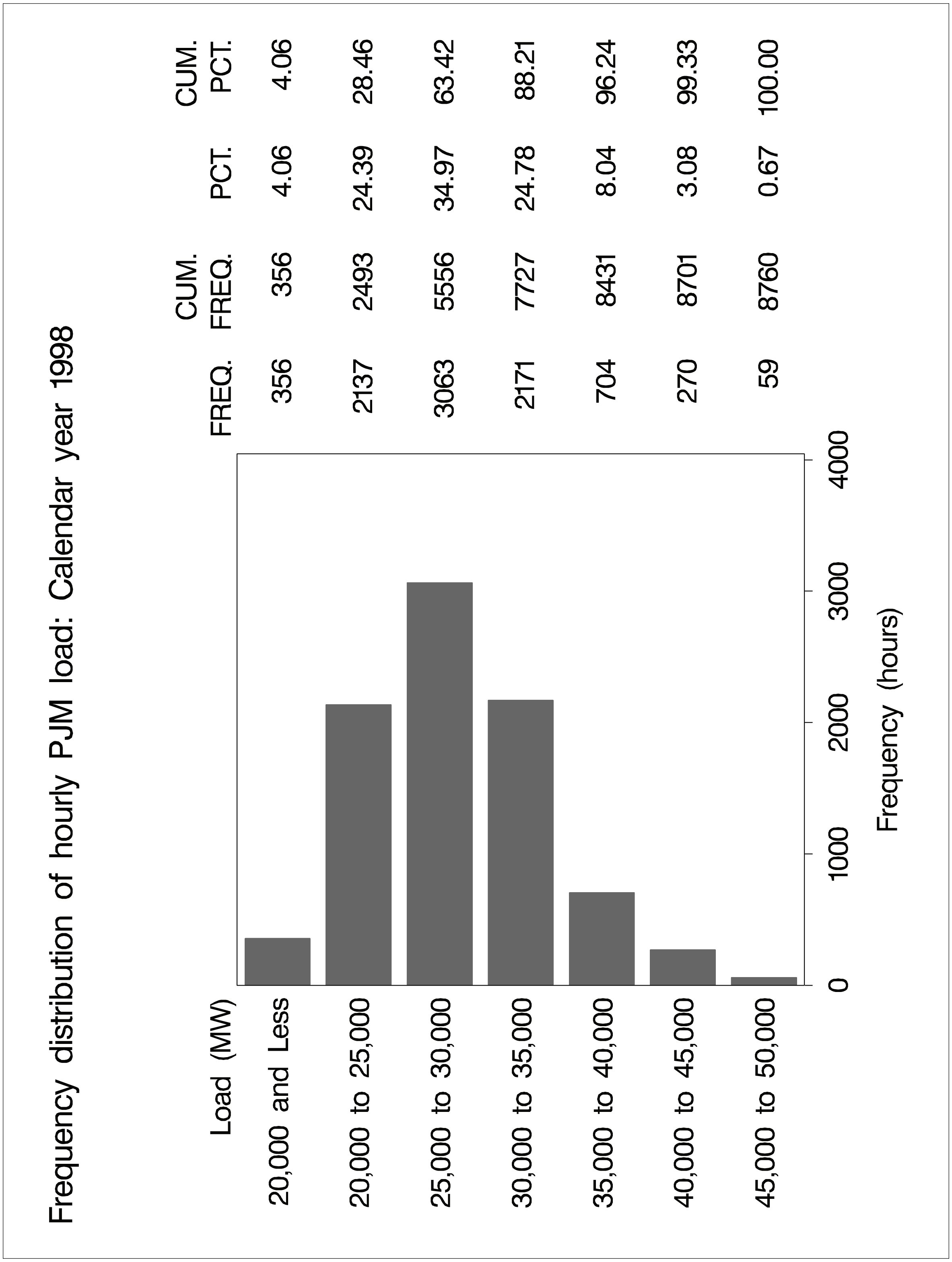


Figure C-10 - Frequency distribution of hourly PJM load: Calendar year 1999

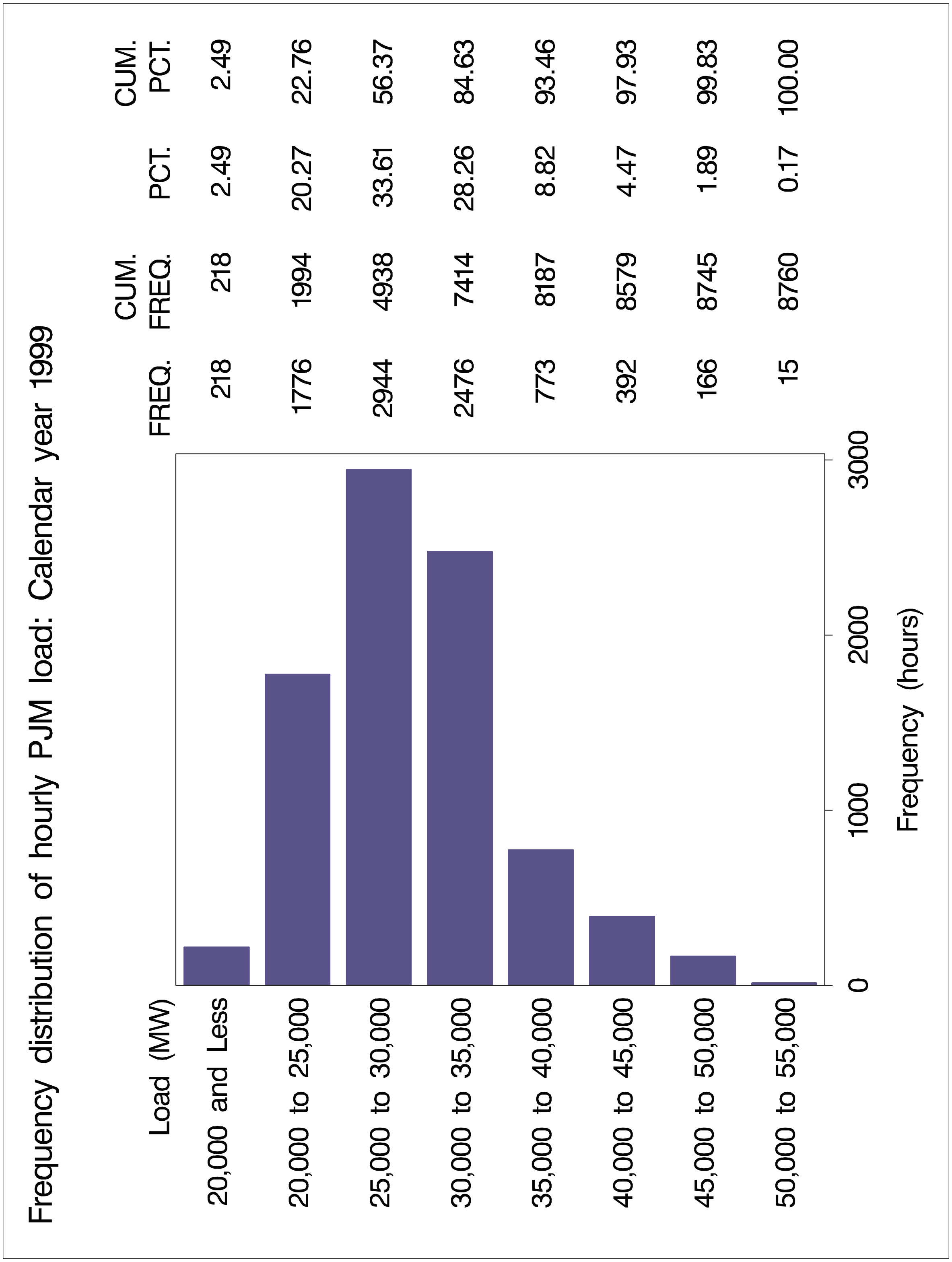
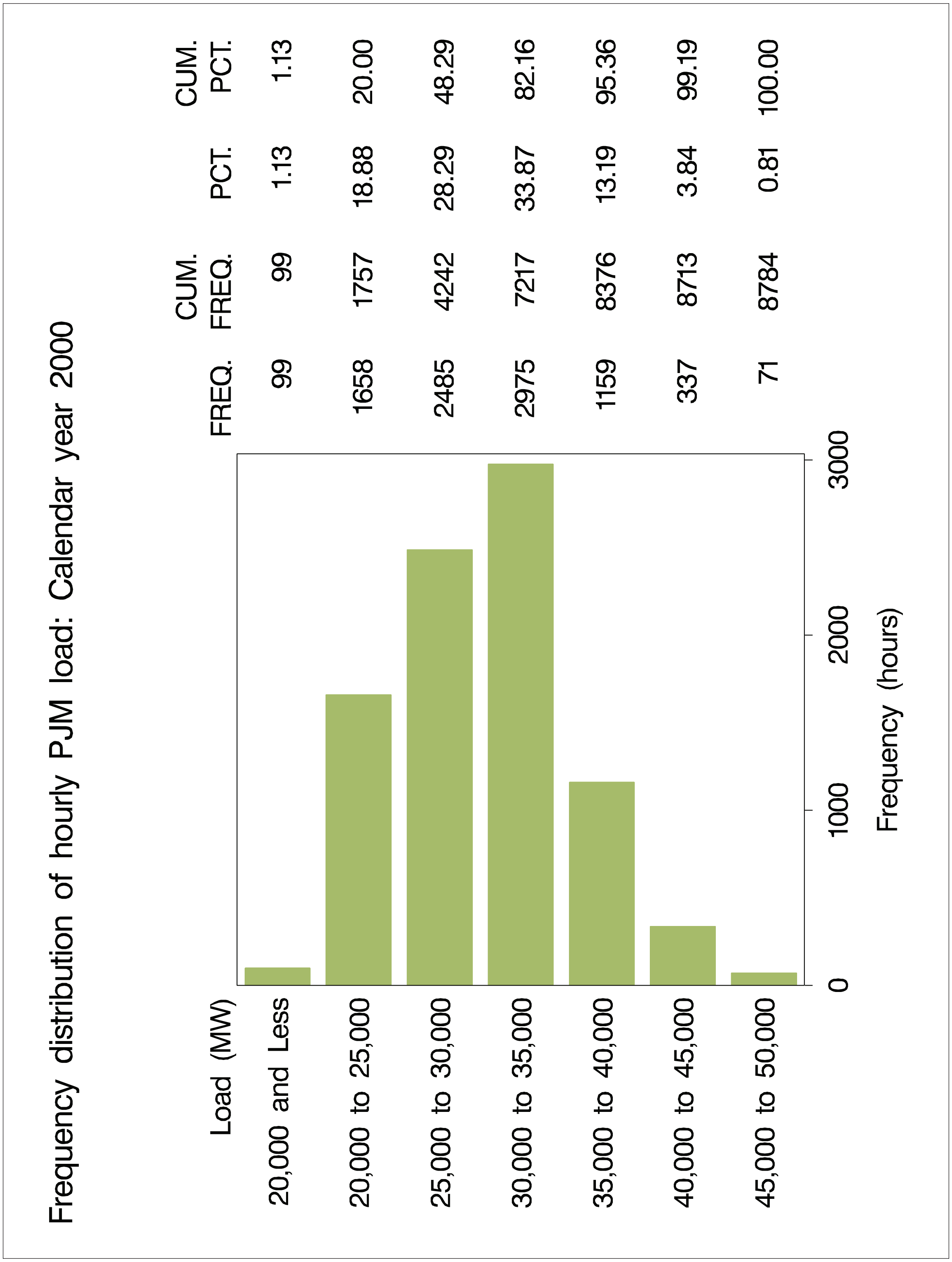
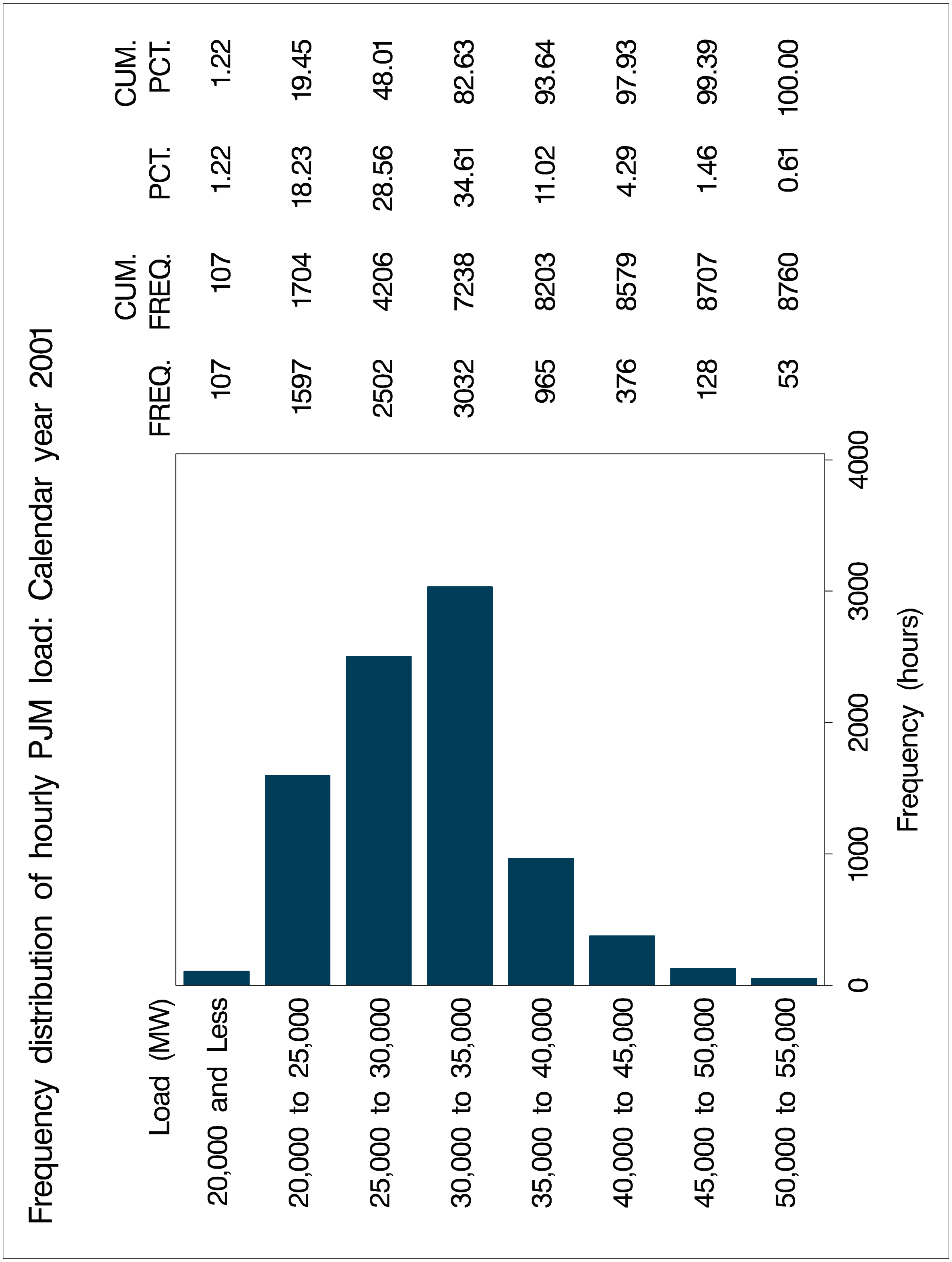


Figure C-11 - Frequency distribution of hourly PJM load: Calendar year 2000



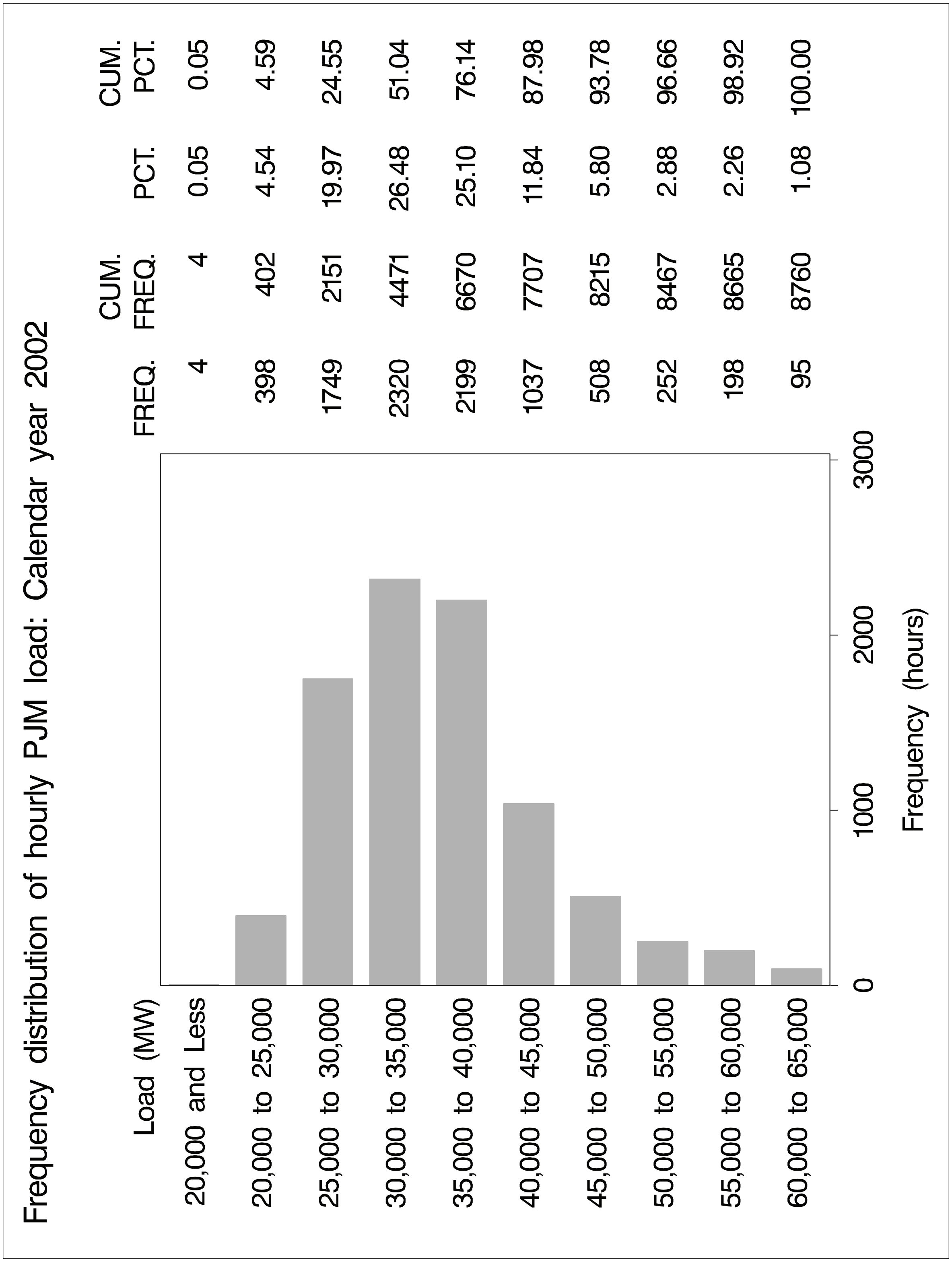
Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	99	99	1.13	1.13
20,000 to 25,000	1658	1757	18.88	20.00
25,000 to 30,000	2485	4242	28.29	48.29
30,000 to 35,000	2975	7217	33.87	82.16
35,000 to 40,000	1159	8376	13.19	95.36
40,000 to 45,000	337	8713	3.84	99.19
45,000 to 50,000	71	8784	0.81	100.00

Figure C-12 - Frequency distribution of hourly PJM load: Calendar year 2001



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	107	107	1.22	1.22
20,000 to 25,000	1597	1704	18.23	19.45
25,000 to 30,000	2502	4206	28.56	48.01
30,000 to 35,000	3032	7238	34.61	82.63
35,000 to 40,000	965	8203	11.02	93.64
40,000 to 45,000	376	8579	4.29	97.93
45,000 to 50,000	128	8707	1.46	99.39
50,000 to 55,000	53	8760	0.61	100.00

Figure C-13 - Frequency distribution of hourly PJM load: Calendar year 2002



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	4	4	0.05	0.05
20,000 to 25,000	398	402	4.54	4.59
25,000 to 30,000	1749	2151	19.97	24.55
30,000 to 35,000	2320	4471	26.48	51.04
35,000 to 40,000	2199	6670	25.10	76.14
40,000 to 45,000	1037	7707	11.84	87.98
45,000 to 50,000	508	8215	5.80	93.78
50,000 to 55,000	252	8467	2.88	96.66
55,000 to 60,000	198	8665	2.26	98.92
60,000 to 65,000	95	8760	1.08	100.00

Figure C-14 - Frequency distribution of hourly PJM load: Calendar year 2003

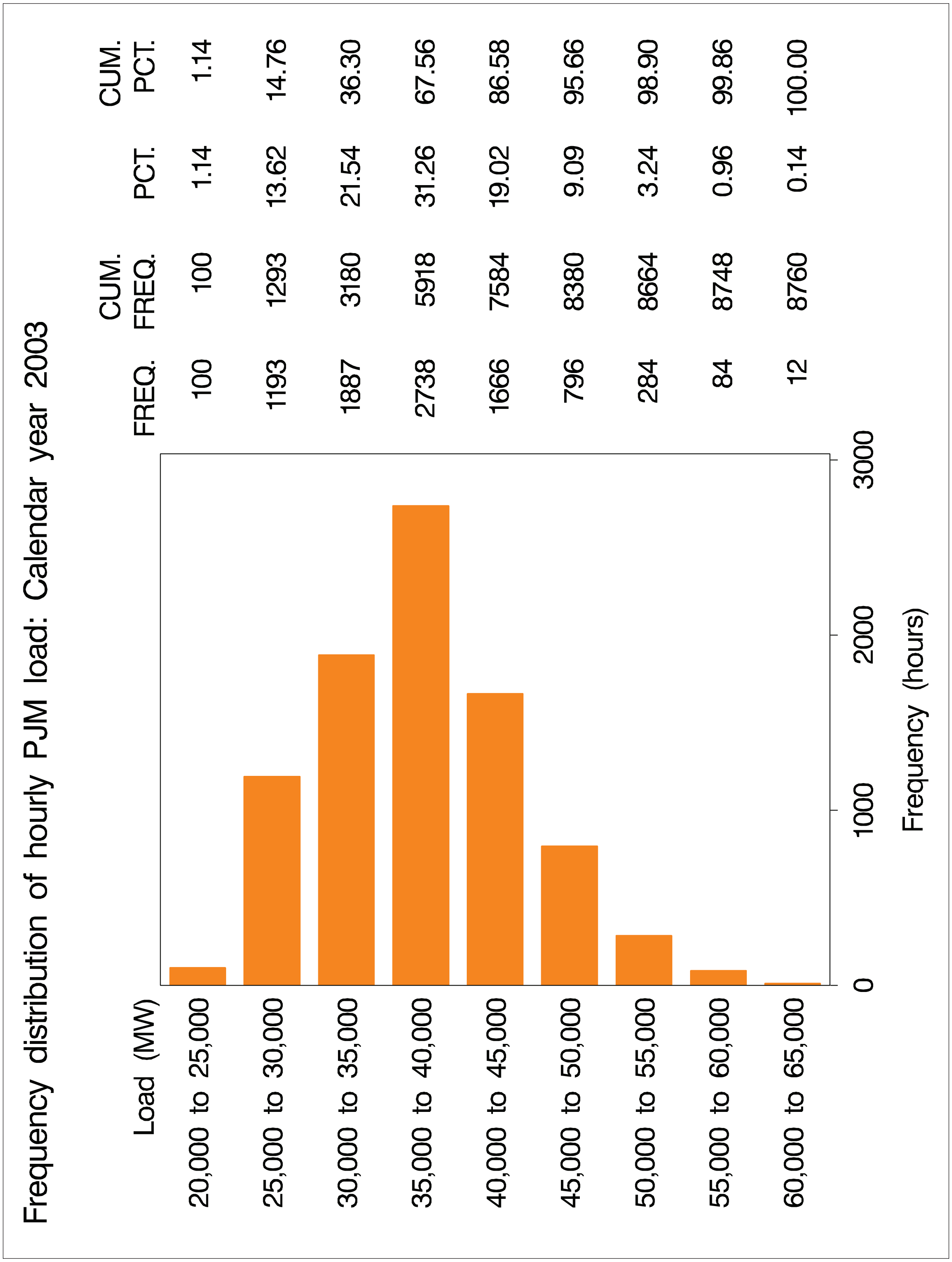
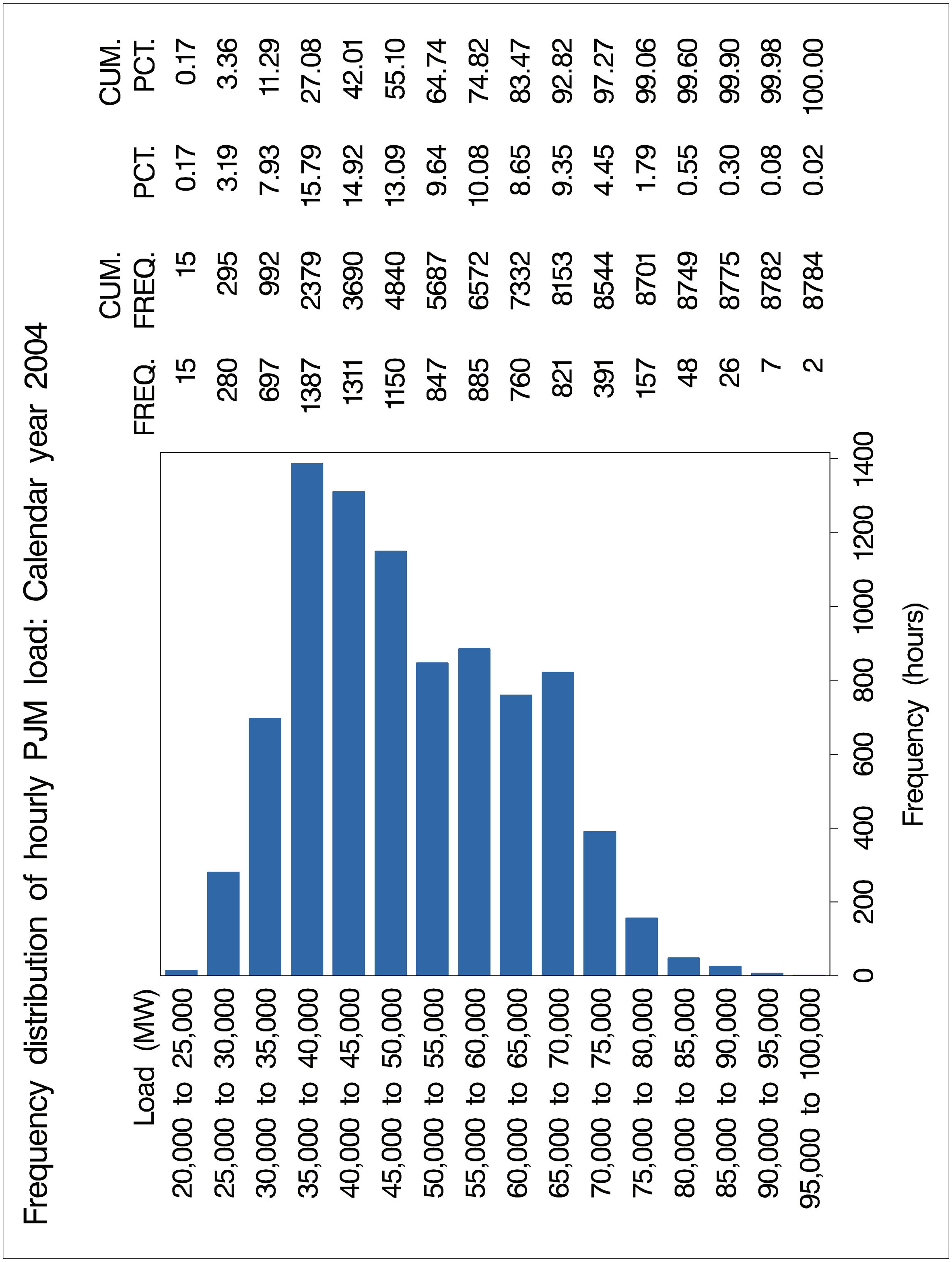


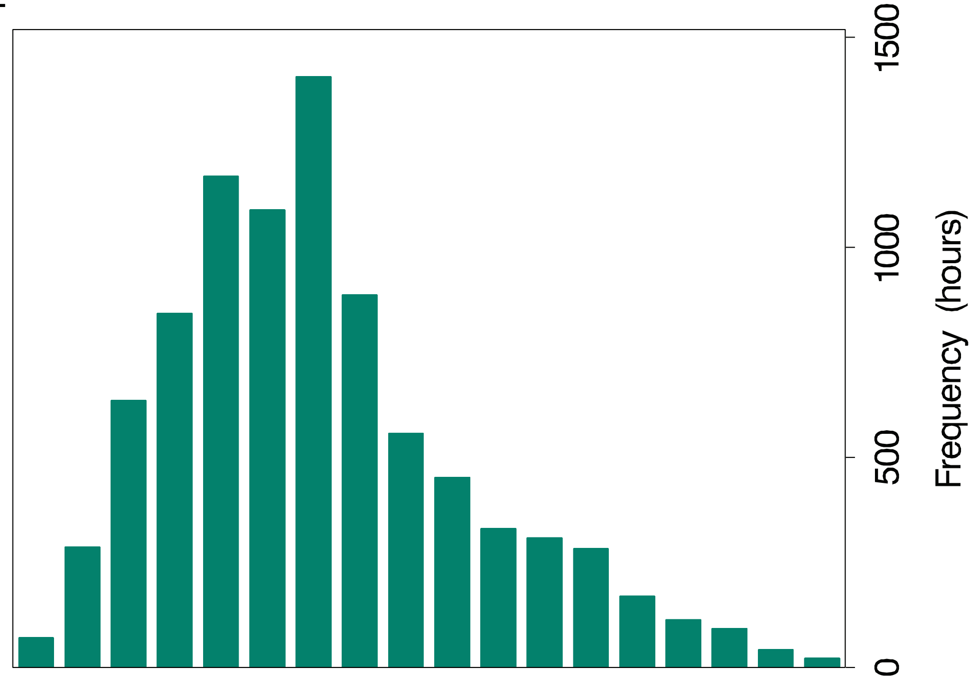
Figure C-15 - Frequency distribution of hourly PJM load: Calendar year 2004



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 to 25,000	15	15	0.17	0.17
25,000 to 30,000	280	295	3.19	3.36
30,000 to 35,000	697	992	7.93	11.29
35,000 to 40,000	1387	2379	15.79	27.08
40,000 to 45,000	1311	3690	14.92	42.01
45,000 to 50,000	1150	4840	13.09	55.10
50,000 to 55,000	847	5687	9.64	64.74
55,000 to 60,000	885	6572	10.08	74.82
60,000 to 65,000	760	7332	8.65	83.47
65,000 to 70,000	821	8153	9.35	92.82
70,000 to 75,000	391	8544	4.45	97.27
75,000 to 80,000	157	8701	1.79	99.06
80,000 to 85,000	48	8749	0.55	99.60
85,000 to 90,000	26	8775	0.30	99.90
90,000 to 95,000	7	8782	0.08	99.98
95,000 to 100,000	2	8784	0.02	100.00

Figure C-16 - Frequency distribution of hourly PJM load: Calendar year 2005

Frequency distribution of hourly PJM load: Calendar year 2005



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
45,000 to 50,000	71	71	0.81	0.81
50,000 to 55,000	286	357	3.26	4.08
55,000 to 60,000	636	993	7.26	11.34
60,000 to 65,000	843	1836	9.62	20.96
65,000 to 70,000	1170	3006	13.36	34.32
70,000 to 75,000	1089	4095	12.43	46.75
75,000 to 80,000	1407	5502	16.06	62.81
80,000 to 85,000	887	6389	10.13	72.93
85,000 to 90,000	557	6946	6.36	79.29
90,000 to 95,000	453	7399	5.17	84.46
95,000 to 100,000	330	7729	3.77	88.23
100,000 to 105,000	308	8037	3.52	91.75
105,000 to 110,000	283	8320	3.23	94.98
110,000 to 115,000	169	8489	1.93	96.91
115,000 to 120,000	113	8602	1.29	98.20
120,000 to 125,000	93	8695	1.06	99.26
125,000 to 130,000	43	8738	0.49	99.75
130,000 to 135,000	22	8760	0.25	100.00

Temperature and Humidity Index (THI)

Table C-1, Table C-2, Table C-3 and Table C-4 show the monthly average of the daily maximum THI values of four representative sites within the PJM footprint: Philadelphia, Pennsylvania; Chicago, Illinois; Columbus, Ohio; and Richmond, Virginia.[4] THI is defined as follows:

temperature - .55* (1-relative humidity/100) * (temperature – 58).[5]

As Table C-1, Table C-2, Table C-3 and Table C-4 show, the monthly averages of the daily maximum THI values for June, July and August within the PJM footprint were higher in 2005 than in 2004. Table C-1 shows the monthly average of the daily maximum THI values for Philadelphia, Pennsylvania, using temperature and humidity data as recorded at the Philadelphia International Airport. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 3.23 percent, 2.66 percent and 3.20 percent, respectively. Table C-2 shows the monthly average of the daily maximum THI values for Chicago, Illinois, using temperature and humidity data as recorded at the O'Hare International Airport. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 5.93 percent, 3.11 percent and 5.43 percent, respectively. Table C-3 shows the monthly average of the daily maximum THI values for Columbus, Ohio, using temperature and humidity data as recorded at the Port Columbus International Airport. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 3.31 percent, 3.03 percent and 4.25 percent, respectively. Table C-4 shows the monthly average of the daily maximum THI values for Richmond, Virginia, using temperature and humidity data as recorded at the Richmond International Airport. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 0.51 percent, 1.53 percent and 3.40 percent, respectively.

Table C-1 - Philadelphia average monthly maximum of temperature-humidity index (THI) comparison

	2004	2005	Difference
May	72.62	64.92	(10.60%)
Jun	73.42	75.79	3.23%
Jul	76.39	78.42	2.66%
Aug	75.86	78.29	3.20%
Sep	72.96	74.36	1.92%

Table C-2 - Chicago average monthly maximum of temperature-humidity index (THI) comparison

	2004	2005	Difference
May	67.79	63.98	(5.62%)
Jun	71.68	75.93	5.93%
Jul	74.29	76.60	3.11%
Aug	71.69	75.58	5.43%
Sep	71.55	72.60	1.47%

4 Temperature and relative humidity data that were used to calculate THI for Philadelphia, Chicago, Columbus and Richmond were obtained from Meteorlogix. See Appendix H, "Glossary," for more detail.

5 See PJM, "Load Data Systems Manual, Section M19," Revision 9 (January 1, 2006), Section 3, pp. 11-16.

Table C-3 - Columbus average monthly maximum of temperature-humidity index (THI) comparison

	2004	2005	Difference
May	71.53	64.95	(9.20%)
Jun	72.83	75.24	3.31%
Jul	75.17	77.45	3.03%
Aug	73.37	76.49	4.25%
Sep	71.86	72.99	1.57%

Table C-4 - Richmond average monthly maximum of temperature-humidity index (THI) comparison

	2004	2005	Difference
May	76.55	68.49	(10.53%)
Jun	76.85	77.24	0.51%
Jul	80.31	81.54	1.53%
Aug	77.85	80.50	3.40%
Sep	74.99	76.79	2.40%

Off-Peak and On-Peak Load

Table C-5 presents summary load statistics for 1998 to 2005 for the off-peak and on-peak hours, while Table C-6 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday through 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-5 shows that on-peak load was about 24.0 percent higher than off-peak load in 2005. With the addition of the DLCO and Dominion Control Zones, average load during on-peak hours in 2005 was 55.6 percent higher than in 2004. Off-peak load in 2005 was 57.5 percent higher than in 2004. (See Table C-6.)

Table C-5 - Off-peak and on-peak load (MW): Calendar years 1998 through 2005

	Average Hourly Load			Median Hourly Load			Standard Deviation of Hourly Load		
	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	1.25	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	1.32	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

Table C-6 - Multiyear change in load: Calendar years 1998 through 2005

	Average Hourly Load		Median Hourly Load		Standard Deviation of Hourly Load	
	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak
1998	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	4.3%	2.8%	20.9%	9.9%
2000	1.8%	1.6%	2.1%	2.5%	(9.7%)	(13.3%)
2001	(0.4%)	1.5%	0.5%	1.0%	(5.4%)	16.0%
2002	18.7%	17.7%	16.0%	16.0%	43.4%	52.9%
2003	5.6%	3.5%	7.6%	6.3%	(8.5%)	(26.9%)
2004	32.9%	34.2%	30.5%	38.7%	95.5%	132.2%
2005	57.5%	55.6%	58.2%	45.8%	17.4%	21.0%

Off-Peak and On-Peak, Load-Weighted LMP: 2004 and 2005

Table C-7 shows load-weighted, average LMP for 2004 and 2005 during off-peak and on-peak periods. In 2004, the on-peak, load-weighted LMP was 49 percent greater than the off-peak LMP, while in 2005, it was 64 percent greater. On-peak, load-weighted, average LMP in 2005 was 48.6 percent higher than in 2004. Off-peak, load-weighted LMP in 2005 was 35.2 percent higher than in 2004. Similarly, both on-peak and off-peak median LMPs were higher in 2005 than in 2004, by 43.5 percent and 21.9 percent, respectively. Dispersion in load-weighted LMP, as indicated by standard deviation, was 94.3 percent higher in 2005 than in 2004 during on-peak hours and was 62.5 percent higher during off-peak hours.

Table C-7 - Off-peak and on-peak, load-weighted LMP (Dollars per MWh): Calendar years 2004 and 2005

	2004			2005			Difference 2004 to 2005	
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak
Average	$35.28	$52.53	1.49	$47.69	$78.04	1.64	35.2%	48.6%
Median	$30.42	$48.39	1.59	$37.08	$69.42	1.87	21.9%	43.5%
Standard Deviation	$19.31	$19.53	1.01	$31.38	$37.95	1.21	62.5%	94.3%

Fuel-Cost Adjustment

Fuel costs for 2004 and 2005 were taken from various published sources. Natural gas prices are the average of the daily cash price for Transco-Z6 (non-New York), Transco- Z5, Chicago Citygates and Texas Eastern-M3 and are adjusted for transportation to the burner tip. Light oil prices are the daily price for No. 2 distillate from the New York Harbor Spot Barge or the Chicago pipeline and are adjusted for transportation. Heavy oil prices are a daily average of the 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 calculated based on unit-specific, cost-based offers.

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. 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 prices. Load-weighted LMP measures the change in reported prices 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 prices actually paid by load after accounting for the change in prices that reflects shifts in underlying fuel prices.

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. The marginal unit fuel factors for the marginal units are one of the components needed to calculate the fuel-cost-adjusted, load-weighted LMP. The marginal unit fuel factors represent the percentage of system load affected by the marginal unit. The marginal unit fuel factors are aggregated by the marginal unit's fuel type and are used in the fuel-cost-adjusted, load-weighted LMP calculation to determine the quantity of load served by the marginal fuel.

The MMU applies an indexing method to adjust nominal LMPs for changes in fuel costs. The index has three components: a term that measures fuel prices in each period; a term that uses marginal unit fuel factors aggregated by fuel type; and a term that measures the MWh generated in each period. The MMU fuel cost index is calculated as a Fisher price index. The Fisher index is a chain-weighted index. A chain-weighted index permits both the MWh generated and fuel prices to change between periods rather than restricting the change to fuel prices only.

LMP during Constrained Hours: 2004 and 2005

Table C-8 presents summary statistics for load-weighted, average LMP during constrained hours in 2004 and 2005 and shows that by this measure price was 46.9 percent higher in 2005 than it had been in 2004. During constrained hours, the median, load-weighted LMP was 36.7 percent higher in 2005 than in 2004, and the dispersion of LMP, as shown by the standard deviation, was 87.8 percent higher in 2005 than in 2004.

Table C-8 - Load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2004 and 2005

	2004	2005	Difference
Average	$45.83	$67.33	46.9%
Median	$41.80	$57.13	36.7%
Standard Deviation	$20.67	$38.81	87.8%

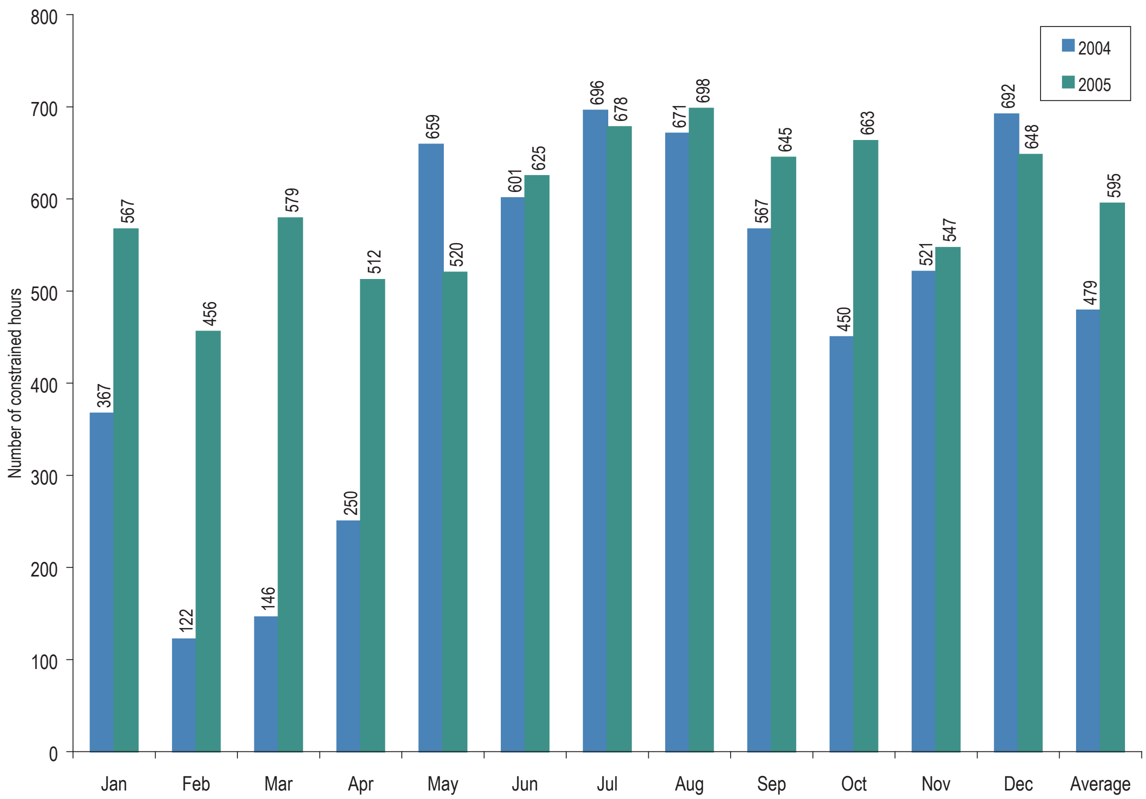
Table C-9 provides a comparison of load-weighted, average LMP during constrained and unconstrained hours for the two years. In 2005, load-weighted, average LMP during constrained hours was 53.0 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2004 was 12.4 percent.

Table C-9 - Load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2004 and 2005

	2004			2005		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$40.79	$45.83	12.4%	$44.00	$67.33	53.0%
Median	$36.62	$41.80	14.1%	$36.80	$57.13	55.3%
Standard Deviation	$22.17	$20.67	(6.8%)	$26.88	$38.81	44.4%

Figure C-17 shows the number of real-time constrained hours during each month in 2004 and 2005 and the average number of constrained hours per month for each year.[6] There were 5,742 constrained hours in 2004 and 7,138 in 2005, an increase of approximately 24.3 percent. Figure C-17 also shows that the average number of constrained hours per month was slightly higher in 2005 than in 2004, with 595 per month in 2005 versus 479 per month in 2004.

Figure C-17 - PJM real-time constrained hours: Calendar years 2004 through 2005

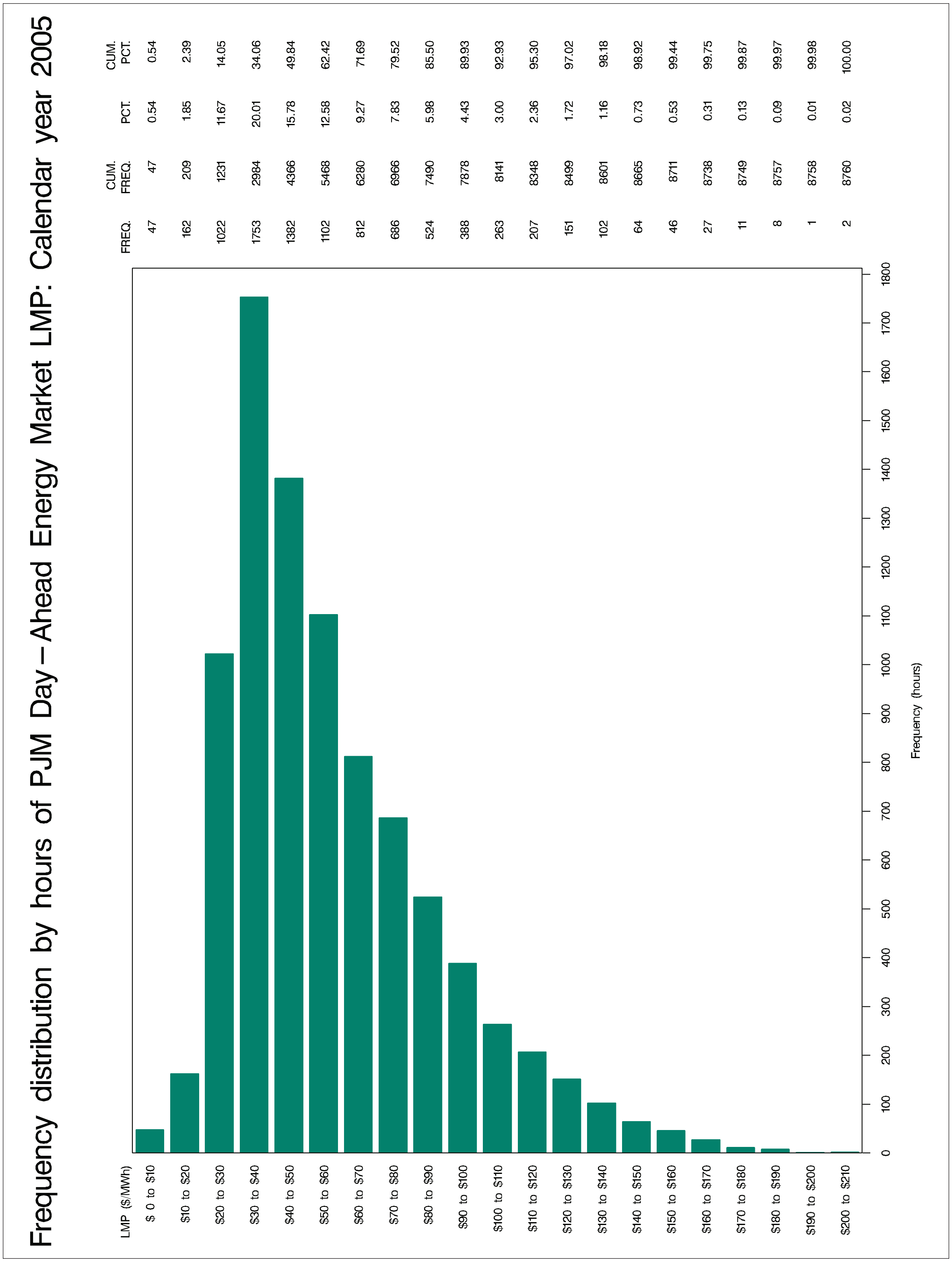


6 The constrained-hour data presented here use the convention that an hour is considered congested when the difference in LMP between at least two buses is greater than $0.00 and congestion occurs for 20 minutes or more within an hour. In prior years, this Appendix to state of the market reports defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

Day-Ahead and Real-Time Prices

On average, prices in the Real-Time Energy Market are slightly higher than those in the Day-Ahead Energy Market and real-time prices show greater dispersion. This pattern of average, systemwide LMP price distribution for 2005 can be seen in Figure C-8 and Figure C-18. Together they show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market, the $30-per-MWh to $40-per-MWh interval occurred during 20.5 percent of the hours. (See Figure C-8.) The most frequently occurring price interval in the PJM Day-Ahead Energy Market was the $30-per-MWh to $40-per-MWh interval with 20.0 percent of the hours. (See Figure C-18.) The $40-per-MWh to $50-per-MWh interval was the next most frequently occurring with 15.8 percent of the hours. The $60-per-MWh to $70-per-MWh interval occurred during 9.3 percent of the hours. In the Real-Time Energy Market, prices were less than $40 per MWh for 39.8 percent of the hours, while prices were less than $40 per MWh in the Day-Ahead Energy Market for 34.1 percent of the hours. Cumulatively, prices were less than $50 per MWh for 53.2 percent of the hours in the Real-Time Energy Market and 49.8 percent of the hours in the Day-Ahead Energy Market; less than $60 per MWh for 63.2 percent of the hours in the Real-Time Energy Market and 62.4 percent of the hours in the Day-Ahead Energy Market; less than $70 per MWh for 71.5 percent of the hours in the Real-Time Energy Market and 71.7 percent of the hours in the Day-Ahead Energy Market. In the Real-Time Energy Market, prices were above $200 per MWh for 35 hours (0.40 percent of the hours), reaching a high for the year of $286.86 per MWh on July 27 during the hour ending 1400 EPT. In the Day-Ahead Energy Market, prices were above $200 per MWh for two hours (0.02 percent of the hours) and reached a high for the year of $207.73 per MWh on August 4, 2005, during the hour ending 1600 EPT.

Figure C-18 - Frequency distribution by hours of PJM Day-Ahead Energy Market LMP: Calendar year 2005



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	47	47	0.54	0.54
$10 to $20	162	209	1.85	2.39
$20 to $30	1022	1231	11.67	14.05
$30 to $40	1753	2984	20.01	34.06
$40 to $50	1382	4366	15.78	49.84
$50 to $60	1102	5468	12.58	62.42
$60 to $70	812	6280	9.27	71.69
$70 to $80	686	6966	7.83	79.52
$80 to $90	524	7490	5.98	85.50
$90 to $100	388	7878	4.43	89.93
$100 to $110	263	8141	3.00	92.93
$110 to $120	207	8348	2.36	95.30
$120 to $130	151	8499	1.72	97.02
$130 to $140	102	8601	1.16	98.18
$140 to $150	64	8665	0.73	98.92
$150 to $160	46	8711	0.53	99.44
$160 to $170	27	8738	0.31	99.75
$170 to $180	11	8749	0.13	99.87
$180 to $190	8	8757	0.09	99.97
$190 to $200	1	8758	0.01	99.98
$200 to $210	2	8760	0.02	100.00

Off-Peak and On-Peak LMP

Table C-10 shows average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets during calendar year 2005. Day-ahead and real-time, on-peak average LMPs were 66 percent and 68 percent higher, respectively, than the corresponding off-peak average LMP. The real-time, on-peak average LMP was 0.7 percent higher than the day-ahead, on-peak average LMP. Median LMPs during on-peak hours were 78 percent and 87 percent higher in the Day-Ahead and Real-Time Energy Markets, respectively, than median LMPs during off-peak hours. In contrast to average prices but consistent with historical experience, the real-time, on-peak median LMP was 1.6 percent lower than the day-ahead, on-peak median 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 (14 percent and 27 percent compared to 11 percent and 19 percent, respectively). The differences reflect larger positive skewness in the Real-Time Energy Market. During on-peak hours, the standard deviation in the Real-Time Energy Market was about 20 percent higher than in the Day-Ahead Energy Market, while it was 32 percent higher during off-peak hours.

Table C-10, Figure C-19 and Figure C-20 show the difference between real-time and day-ahead LMP during calendar year 2005 during the on-peak and off-peak hours, respectively. The difference between real-time and day-ahead average LMP during on-peak hours was $0.53 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 $0.12 per MWh. (Day-ahead LMP was higher than real-time LMP.)

Table C-10 - Off-peak and on-peak hourly LMP (Dollars per MWh): Calendar year 2005

	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
Average	$44.26	$73.54	1.66	$44.14	$74.07	1.68	(0.3%)	0.7%
Median	$37.23	$66.22	1.78	$34.85	$65.14	1.87	(6.4%)	(1.6%)
Standard Deviation	$22.18	$30.25	1.36	$29.20	$36.23	1.24	31.7%	19.8%

Figure C-19 - Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2005

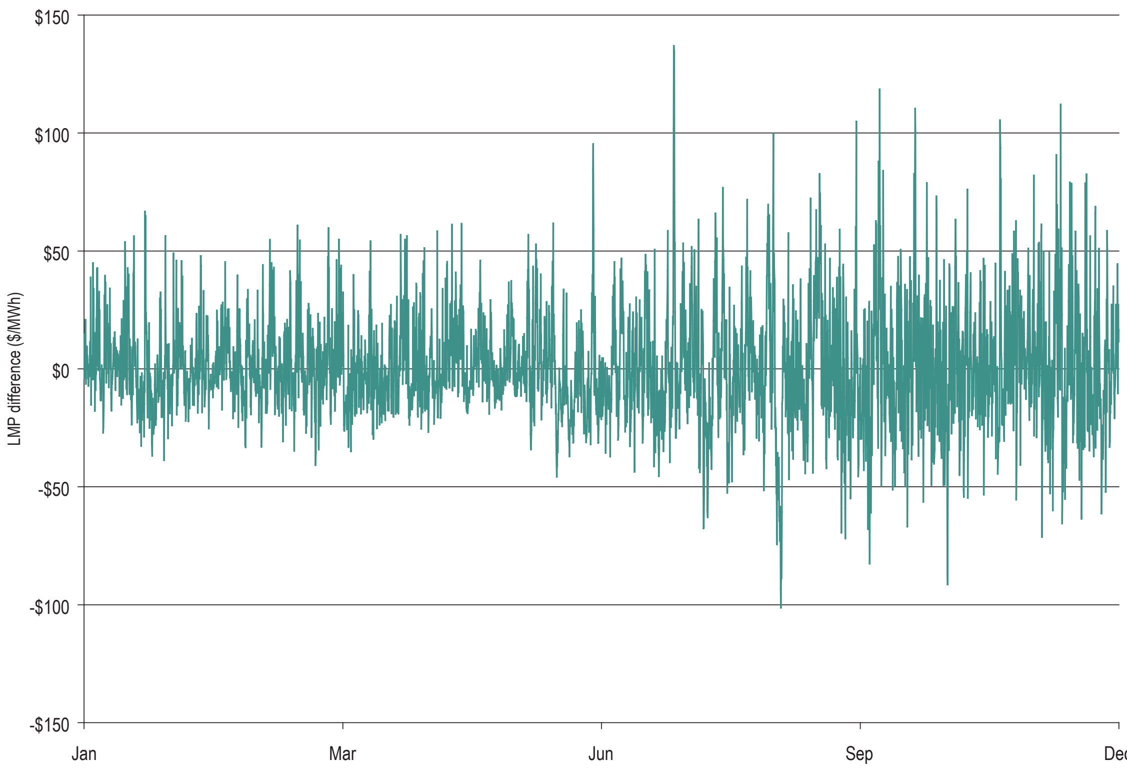
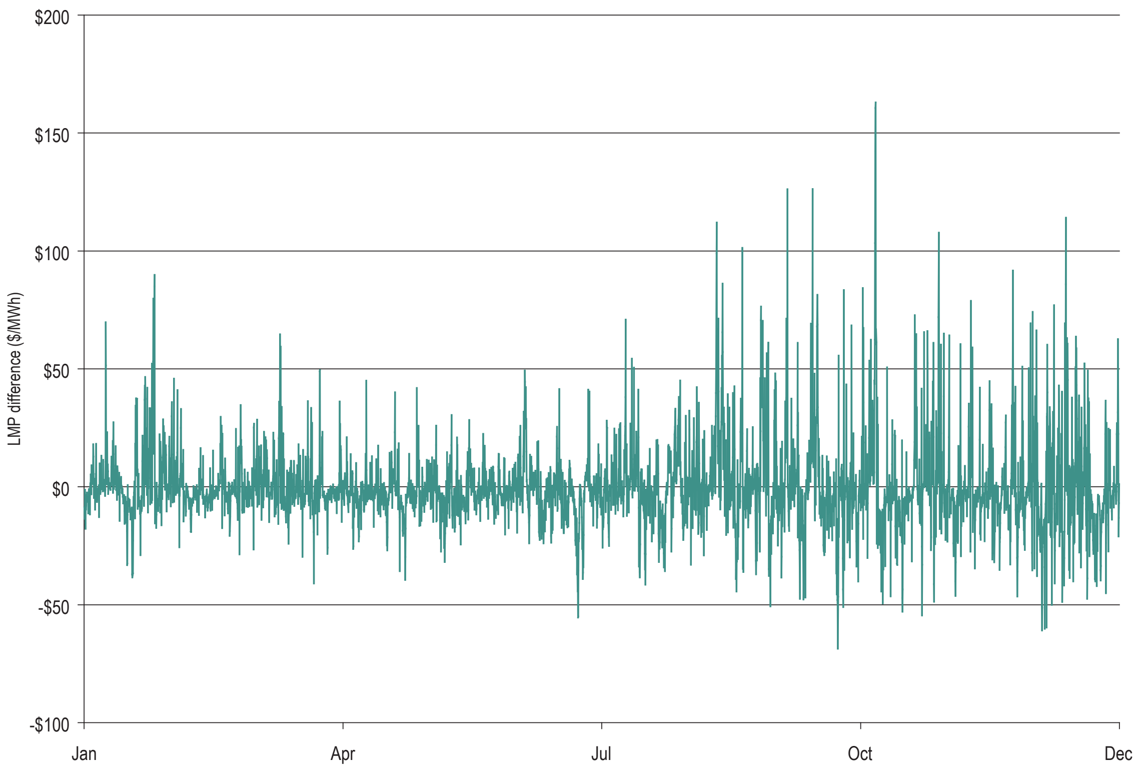


Figure C-20 - Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2005



Off-Peak and On-Peak Zonal LMP

Table C-11 and Table C-12 show the average on-peak and off-peak LMP for each zone in the Day-Ahead and Real-Time Energy Markets during calendar year 2005. The difference between the Day-Ahead and Real-Time Energy Markets is displayed in both dollars per MWh and a percentage difference. The zone with the maximum difference between real-time and day-ahead LMP was the Delmarva Power & Light Control Zone (DPL) with an on-peak, real-time zonal LMP 3.40 percent lower than its on-peak, day-ahead zonal LMP. AEP had the smallest difference with its on-peak, real-time zonal LMP 0.13 percent lower than its on-peak, day-ahead zonal LMP. DLCO had the largest difference between off-peak zonal LMP, with day-ahead LMP 8.54 percent higher than real-time LMP. The zone with the smallest difference in off-peak zonal LMP was the Pennsylvania Electric Company Control Zone (PENELEC) with day-ahead LMP 0.05 percent higher than real-time LMP.

Table C-11 - Zonal on-peak hourly LMP (Dollars per MWh): Calendar year 2005

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$88.76	$86.88	$1.88	2.16%
AEP	$61.82	$61.74	$0.08	0.13%
AP	$73.35	$73.71	($0.36)	(0.49%)
BGE	$83.41	$85.25	($1.84)	(2.16%)
ComEd	$61.24	$61.40	($0.16)	(0.26%)
DAY	$60.51	$60.37	$0.14	0.23%
DLCO	$58.12	$57.92	$0.20	0.35%
Dominion	$90.75	$92.60	($1.85)	(2.00%)
DPL	$85.23	$82.43	$2.80	3.40%
JCPL	$84.34	$83.83	$0.51	0.61%
Met-Ed	$82.25	$81.11	$1.14	1.41%
PECO	$85.16	$82.89	$2.27	2.74%
PENELEC	$71.57	$71.20	$0.37	0.52%
PEPCO	$85.03	$86.55	($1.52)	(1.76%)
PPL	$81.31	$79.50	$1.81	2.28%
PSEG	$87.11	$88.39	($1.28)	(1.45%)
RECO	$83.57	$84.42	($0.85)	(1.01%)

Table C-12 - Zonal off-peak hourly LMP (Dollars per MWh): Calendar year 2005

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$51.67	$51.86	($0.19)	(0.37%)
AEP	$35.92	$34.82	$1.10	3.16%
AP	$44.87	$44.69	$0.18	0.40%
BGE	$52.47	$52.81	($0.34)	(0.64%)
ComEd	$34.48	$33.51	$0.97	2.89%
DAY	$34.91	$33.37	$1.54	4.62%
DLCO	$33.92	$31.25	$2.67	8.54%
Dominion	$54.73	$56.63	($1.90)	(3.36%)
DPL	$51.22	$51.00	$0.22	0.43%
JCPL	$49.61	$49.80	($0.19)	(0.38%)
Met-Ed	$49.78	$49.54	$0.24	0.48%
PECO	$50.75	$50.22	$0.53	1.06%
PENELEC	$43.81	$43.79	$0.02	0.05%
PEPCO	$53.60	$53.89	($0.29)	(0.54%)
PPL	$49.16	$48.71	$0.45	0.92%
PSEG	$52.39	$53.64	($1.25)	(2.33%)
RECO	$51.25	$52.96	($1.71)	(3.23%)

Off-Peak and On-Peak, Load-Weighted, Fuel-Cost-Adjusted LMP

Table C-13 and Table C-14 show the average load-weighted LMP and the average load-weighted, fuel-cost-adjusted LMP for 1999 through 2005 for on-peak and off-peak hours. During on-peak hours the load-weighted, fuel-cost-adjusted LMP in 2005 increased by 5.8 percent over the load-weighted LMP in 2004. However, the load-weighted, fuel-cost-adjusted LMP in 2005 decreased by 3.2 percent in the off-peak hours compared to the load-weighted LMP in 2004.

Table C-13 - On-peak PJM load-weighted, fuel-cost-adjusted LMP (Dollars per MWh): Year-over-year method

	1999	2000	2001	2002	2003	2004	2005
Load-Weighted LMP	$45.31	$38.80	$48.36	$39.78	$49.97	$52.53	$78.04
Load-Weighted and Fuel-Cost-Adjusted LMP	NA	$25.92	$47.75	$42.81	$38.59	$46.92	$55.57
Year-over-Year Comparison	NA	(42.8%)	23.1%	(11.5%)	(3.0%)	(6.1%)	5.8%

Table C-14 - Off-peak PJM load-weighted, fuel-cost-adjusted LMP (Dollars per MWh): Year-over-year method

	1999	2000	2001	2002	2003	2004	2005
Load-Weighted LMP	$21.65	$21.93	$23.59	$22.51	$31.75	$35.28	$47.69
Load-Weighted and Fuel-Cost-Adjusted LMP	NA	$14.45	$23.34	$24.37	$24.26	$31.88	$34.14
Year-over-Year Comparison	NA	(33.3%)	6.4%	3.3%	7.8%	0.4%	(3.2%)

LMP during Constrained Hours: Day-Ahead and Real-Time Energy Markets

Figure C-21 shows the number of constrained hours in each month for the Day-Ahead and Real-Time Energy Markets and the average number of constrained hours for 2005. Overall, there were 7,138 constrained hours in the Real-Time Energy Market and 8,732 constrained hours in the Day-Ahead Energy Market. Figure C-21 shows that in every month of calendar year 2005 the number of constrained hours in the Day-Ahead Energy Market exceeded those in the Real-Time Energy Market. On average for the year, the Day-Ahead Energy Market had 22.4 percent more constrained hours than the Real-Time Energy Market.

Figure C-21 - Day-ahead and real-time, market-constrained hours: Calendar year 2005

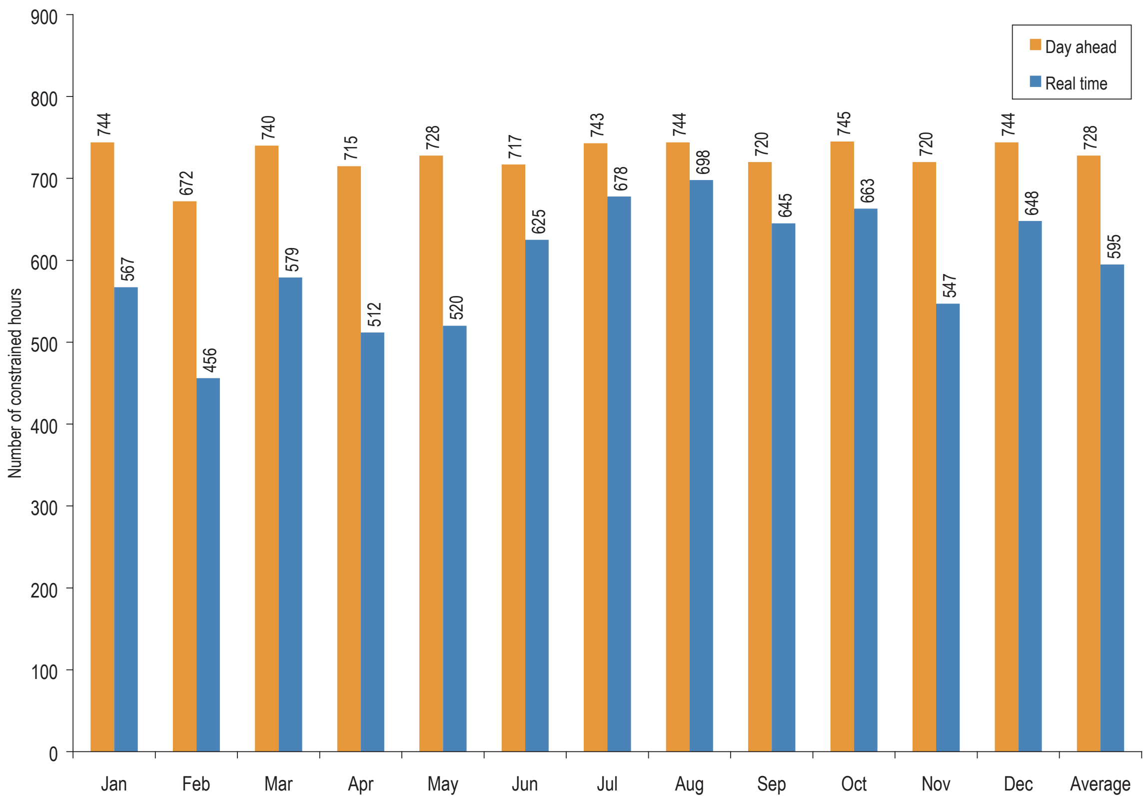


Table C-15 shows average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets. In the Day-Ahead Energy Market, average LMP during constrained hours was 104.8 percent higher than average LMP during unconstrained hours. In the Real-Time Energy Market, average LMP during constrained hours was 51.7 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 6.9 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 44.3 percent higher in the Real-Time Market than in the Day-Ahead Market.

Table C-15 - LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2005

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$28.32	$57.99	104.8%	$40.87	$61.99	51.7%
Median	$17.33	$50.17	189.5%	$34.29	$51.03	48.8%
Standard Deviation	$23.18	$30.01	29.5%	$25.75	$36.74	42.7%

Taken together, the data show that average LMP in the Day-Ahead Energy Market during constrained hours was 0.2 percent higher than the overall average LMP for the Day-Ahead Energy Market, while average LMP during unconstrained hours was 51.1 percent lower.[7] In the Real-Time Energy Market, average LMP during constrained hours was 6.7 percent higher than the overall average LMP for the Real-Time Energy Market, while average LMP during unconstrained hours was 29.6 percent lower.

7 See Section 2, "Energy Market, Part 1" for a discussion of load and LMP.

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/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.

PJM Interface Pricing Point Definition – General Methodology[3]

PJM establishes prices for transactions with external control areas by assigning interface pricing points to external control areas. The interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically. External control areas are either adjacent to PJM or not adjacent to PJM.

Transactions between PJM and external control areas need to be priced at the PJM border. A set of external pricing points is used to create such interface prices. The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and an external control area and, therefore, to create price signals that embody the underlying economic and electrical system fundamentals. Transactions between adjacent control areas and PJM flow on one or more physical tie lines that constitute the interface between the two control areas.

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.

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 This discussion of the PJM methodology for defining interface pricing points relies on the PJM analysis and associated white papers developed in conjunction with the 2004 integrations. See generally PJM, "AEP & DP&L Transmission and Market Integration White Paper, Version 1.4" (September 24, 2004); and PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004).

Each adjacent control area either has a separate interface pricing point or, if distribution factor analysis shows that identified adjacent control areas have similar electrical effects on the tie lines connecting them to PJM, multiple adjacent control areas can use a common interface price definition. Thus an interface price definition may include external pricing points from one adjacent control area or a combination of adjacent control areas.

PJM analysis for the ComEd integration showed that transactions from specific, adjacent control areas had very similar electrical effects on PJM and were, therefore, given the same interface price definition. For example, MEC and Alliant Energy Corporation West (ALTW) are adjacent control areas with similar electrical effects on tie lines connecting them to PJM. As a result, the interface price is the same for both control areas and consists of a combination of external pricing points from both the adjacent control areas.

PJM analysis for the AEP and DAY Control Zone integrations showed a number of adjacent control areas with very similar effects on tie lines connecting them to PJM. As a result, single interface pricing points were created to define groups of adjacent control areas. As an example, a group of control areas with similar electrical effects on PJM was determined to include Central Illinois Light Company (CILCO), Illinois Power Company (IP), Indianapolis Power & Light Company (IPL), Ameren, Cinergy Corporation (CIN), East Kentucky Power Cooperative, Inc. (EKPC), LG&E Energy, L.L.C. (LGEE) and Tennessee Valley Authority (TVA). The Southwest pricing point was defined as the single interface price used to price transactions to or from any location within this group of adjacent control areas.

Transactions from external, non-adjacent control areas are also priced at interface prices. PJM, in its AEP and DAY transition white paper, describes how standard power flow analysis tools are used to simulate transactions with external, non-adjacent control areas to obtain distribution factor data. The distribution factor data are analyzed to determine through which adjacent control area the majority of power from the external, non-adjacent control area flows. By calculating the correlation coefficient between the external, non-adjacent control area distribution factor and the distribution factor for each of the adjacent control areas, PJM determines the association of an external control area with one of the adjacent control areas and assigns a corresponding interface price.

A more complex situation arises when a transaction from an external, non-adjacent control area results in similar flows on multiple interfaces with different interface price definitions. In that case, an additional interface price definition may be required to reflect the impact of transactions from the external, non-adjacent control area on multiple interface pricing points defined with adjacent control areas. As an example, flows between the Ontario Independent Electricity System Operator (Ontario IESO) and PJM tend to be split between adjacent control areas, primarily the New York Independent System Operator (NYIS) and the FirstEnergy Corp. (FE), each of which has a different interface price. Neither interface price was separately appropriate for transactions with the Ontario IESO. So PJM created the Ontario IESO interface price to include both interface prices so as to appropriately reflect the price for transactions with the Ontario IESO.

Phase 4 Integration of the DLCO Control Zone

With the integration of the DLCO Control Zone into PJM, the DLCO interface was retired. As a result, interface pricing points were reduced from nine to eight and the number of interfaces from 23 to 22. These pricing points are defined in Table D-1.

Table D-1 - DLCO integration interface pricing point definitions:[4] During Phase 4

	Included Control Areas
Northwest	Wisconsin Energy Corporation, Alliant Energy Corporation East, ALTW, MEC
Southwest	CILCO, IP, IPL, Ameren, CIN, EKPC, LGEE, TVA
OVEC	Ohio Valley Electric Corporation
NIPSCO	Northern Indiana Public Service Company
Southeast	Carolina Power & Light Company West, Carolina Power & Light Company East, Duke Power, Dominion Virginia Power
Ontario IESO	Ontario IESO
MICHFE	Michigan Electric Coordinated System, FE
NYIS	NYIS

Midwest ISO Begins Market-Based Operation

On April 1, 2005, the Midwest ISO began operation of its market-based system. This required PJM to establish a new pricing point at the border, increasing the number of pricing points from eight to nine. (See Table D-2.)

Table D-2 - Midwest ISO startup interface pricing point definitions:[5] From April 1, 2005, through December 31, 2005

	Included Control Areas
Northwest	Wisconsin Energy Corporation, Alliant Energy Corporation East, ALTW, MEC
Southwest	CILCO, IP, IPL, Ameren, CIN, EKPC, LGEE, TVA
OVEC	Ohio Valley Electric Corporation
NIPSCO	Northern Indiana Public Service Company
Southeast	Carolina Power & Light Company West, Carolina Power & Light Company East, Duke Power, Dominion Virginia Power
Ontario IESO	Ontario IESO
MICHFE	Michigan Electric Coordinated System, FE
NYIS	NYIS
MISO	Midwest ISO

Phase 5 Integration of the Dominion Control Zone

With the integration of the Dominion Control Zone into PJM on May 1, the Dominion interface was retired. Its elimination reduced interfaces from 22 to 21. The Southeast interface pricing point was modified to account for the integration.

4 See Section 4, "Interchange Transactions," for a discussion of the evolution of pricing points during 2005.
5 See Section 4, "Interchange Transactions," for a discussion of the evolution of pricing points during 2005.

APPENDIX E – CAPACITY MARKETS[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 provides a mechanism to balance supply and demand for capacity credits not met through the bilateral market or self-supply. The PJM Capacity Credit Market is designed to provide a transparent mechanism through which all competitors can buy and sell capacity based on need.

With the Phase 2 integration of the Commonwealth Edison Company (ComEd) into PJM on May 1, 2004,[3] the "PJM-West Reliability Assurance Agreement Among Load-Serving Entities in the PJM-West Region" was amended by Schedule 17.[4] It specified capacity market rules that would be implemented only in the ComEd Capacity Market during an interim 13-month period that ended on May 31, 2005. The market rules were specified in terms of installed, rather than unforced, capacity and operated on a monthly basis. The ComEd Capacity Credit Market did not include the Daily Capacity Credit Market Auctions that are a feature of the Capacity Credit Market in the rest of PJM. Beginning on June 1, 2005, however, when the interim market ended, all ComEd Control Zone capacity transactions and obligations operated under the PJM Capacity Market rules then in effect.

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. On June 1, 2005, all control zones participated in a single regional transmission organization (RTO) Capacity Market. Until then and for the purposes of the *2005 State of the Market Report*, the interim capacity market is referred to as the ComEd Capacity Market, the ComEd Capacity Credit Market or simply ComEd.

Zones, 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. The geographic areas did not change with the formalization of the control zone and control area concepts during the Phase 4 and Phase 5 integrations. For simplicity, zones are referred to as control zones for both phases. The only exception is ComEd which was called the ComEd Control Area for 2004 Phase 2 only.

2 The first PJM Capacity Credit Markets (CCMs) were run in late 1998, with an effective date of January 1, 1999.

3 Since the ComEd Control Area's Capacity Market did not open until June 1, 2004, throughout May 2004 the Commonwealth Edison Company covered all capacity obligations operating under the guidance of PJM. See "Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone during the Interim Period." See also "PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region," Section L (December 20, 2004), pp. 48C – 48D.

4 "Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone During the Interim Period." See also "PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region" (December 20, 2004), pp. 48A – 48D.

Under the RAA governing Capacity Markets 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

For both the PJM Capacity Market and the interim ComEd Capacity Market, load forecasts are used to determine a forecast peak load. These forecast peak-load values are further adjusted to establish capacity obligations.

- **The PJM Capacity Market**. The adjusted forecast peak-load value[5] is multiplied by the forecast pool requirement (FPR) to determine the unforced capacity obligation for PJM. 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[6] 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.

- **The Interim ComEd Capacity Market.** The adjusted forecast peak-load value was multiplied by an installed reserve margin (IRM) to determine the capacity obligation. The IRM was to equal to one plus a reserve margin. The IRM was set for three consecutive intervals: a 1.15 IRM for the summer interval running from June 1, 2004, through September 30, 2004; a 1.4 IRM for the fall interval running from October 1, 2004, through December 31, 2004: and a 1.4 IRM for the winter interval running from January 1, 2005, through May 31, 2005.

  Each individual LSE's capacity obligation was based on its customers' aggregate share of the summer interval's forecasted peak load multiplied by the IRM. The amount was further adjusted for mandatory interruptible load (MIL). This allocation was also used to determine adjusted, peak-load values for the fall and winter intervals.

Meeting Capacity Obligations

- **The PJM Capacity Market.**[7] 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.[8] 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.

5 Adjusted for active load-management (ALM).
6 Zonal scaling factors are applied to historical peak loads to produce forecasted zonal peak loads.
7 See "PJM Manual 17, Capacity Obligations, Revision 06" (June 1, 2005) <http://www.pjm.com/contributions/pjm-manuals/pdf/m17vo6.pdf>(105 KB).
8 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, and to $171.18 per MW-day, effective January 1, 2005.

- **The Interim ComEd Capacity Market.** By contrast, in this Capacity Market, an LSE's load could only change monthly to reflect load shifts between LSEs as customers switch suppliers. In the ComEd Capacity Market, installed capacity rather than unforced capacity was used to meet capacity obligations. Deficient entities were required to contract for capacity resources to satisfy their deficiency. Any LSE that remained deficient had to pay a deficiency charge equal to the MW of deficiency times the daily deficiency rate,[9] times the number of days in the interval.

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.[10]

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 for the PJM Capacity Market or in terms of installed capacity for the interim ComEd Capacity Market.

- **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.

- **Capacity Credit Markets.** For the PJM Capacity Market, market purchases may be made from the Daily, Monthly or Multimonthly Capacity Credit Market 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 as 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 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.[11] 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.

9 Effective June 1, 2004, the daily deficiency rate was $160.00 per MW-day.
10 See PJM "Reliability Assurance Agreement," "Capacity Resources" (May 17, 2004), p. 2.
11 See "PJM Manual 13, Emergency Operations, Revision 19" (October 1, 2004) <http://www.pjm.com/ contributions/pjm-manuals/pdf/m13v19.pdf> (461 KB).

- **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,[12] 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.[13]

Market Dynamics

RAA procedures determine the total capacity obligation for both the PJM Capacity Market and the interim ComEd Capacity Market and thus the total demand for capacity in each market. The RAA includes rules for allocating total capacity obligation to individual LSEs in each market. An LSE's deficiency, in either market, is equivalent to its allocated capacity obligation, net of bilateral contracts, self-supply and the applicable active load management (ALM in the PJM Capacity Market) or mandatory interruptible load (MIL in the interim ComEd Capacity Market). LSEs bid this deficiency into the appropriate Capacity Credit Market Auctions.

The short- and intermediate-term supply of capacity credits in either 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.

12 Deliverable per Schedule 10, PJM "Reliability Assurance Agreement" (May 17, 2004), p. 52 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).
13 See Schedule 12, PJM "Reliability Assurance Agreement" (May 17, 2004), p. 57 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

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. The competitive price in the capacity markets 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 (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 price differential exceeding the capacity penalty for the period is lower and, therefore, the incentives to sell the system short are lower.

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. PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standards (CPS) that 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.[1]

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.[2]

Control Performance Standard (CPS)

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 second measure is a statistical measure of unacceptably large net unscheduled power flows. These two measures define the NERC Control Performance Standard. The NERC Control Performance Standard is the measure against which all control areas are evaluated.

- **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.[3]

- **CPS2.** 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

1 Regulation Market business rules are defined in "PJM Manual 11: Scheduling Operations," Revision 26 (November 9, 2005), pp. 48-56.

2 See "PJM Dispatching Operations Manual, M-12," Revision 12, Section 4 (August 16, 2005), p. 44.

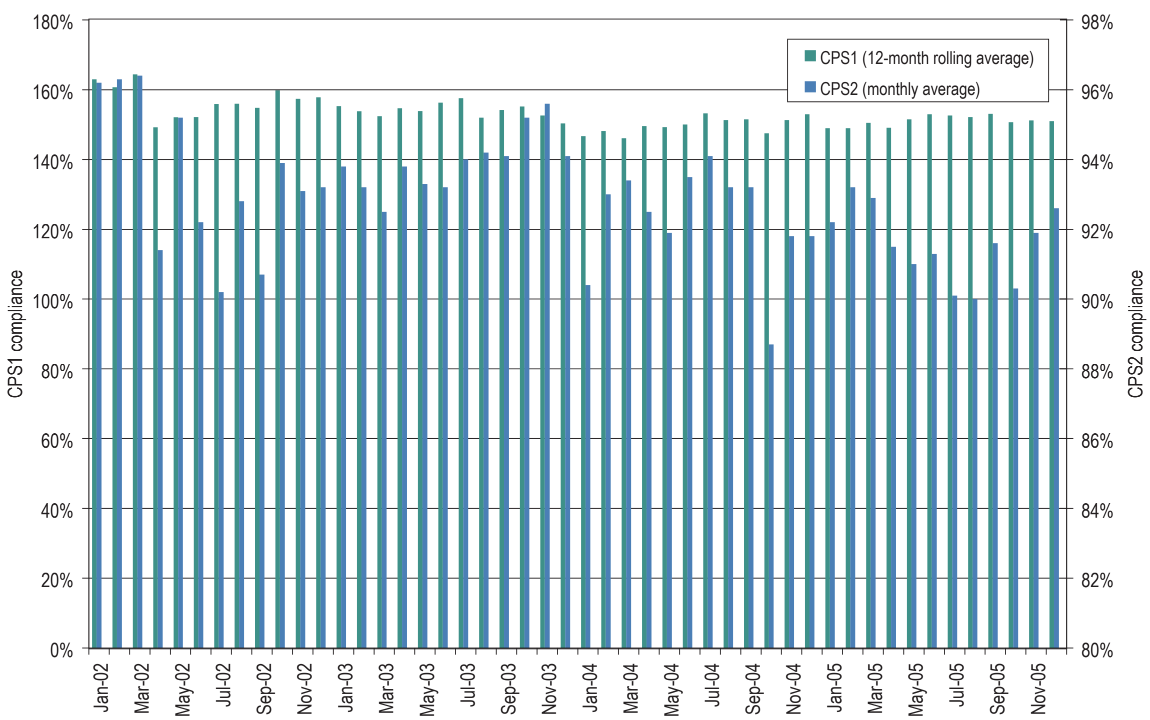
3 For more information about the definition and calculation of CPS, refer to "M12: Dispatching Operations," Revision 11 (January 1, 2005), pp. 19-21. The formal definition of CPS1 can be found in NERC's "Performance Standards Reference Document," version 2 (November 21, 2002), Section B.1.1.1. The formal definition of CPS2 can be found in NERC's "Performance Standards Reference Document," version 2 (November 21, 2002), Section B.1.1.2.

a month when the 10-minute average of the PJM Control Area's ACE is within defined limits known as L10. 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 L10. From January 1 through January 31, 2005, the PJM Control Area's L10 standard was 258.5 MW. From February 1 through April 30, PJM's L10 standard was 261.9 MW. After the integration of Dominion (Phase 5), PJM's L10 standard was 281.2 MW.

PJM's CPS Performance

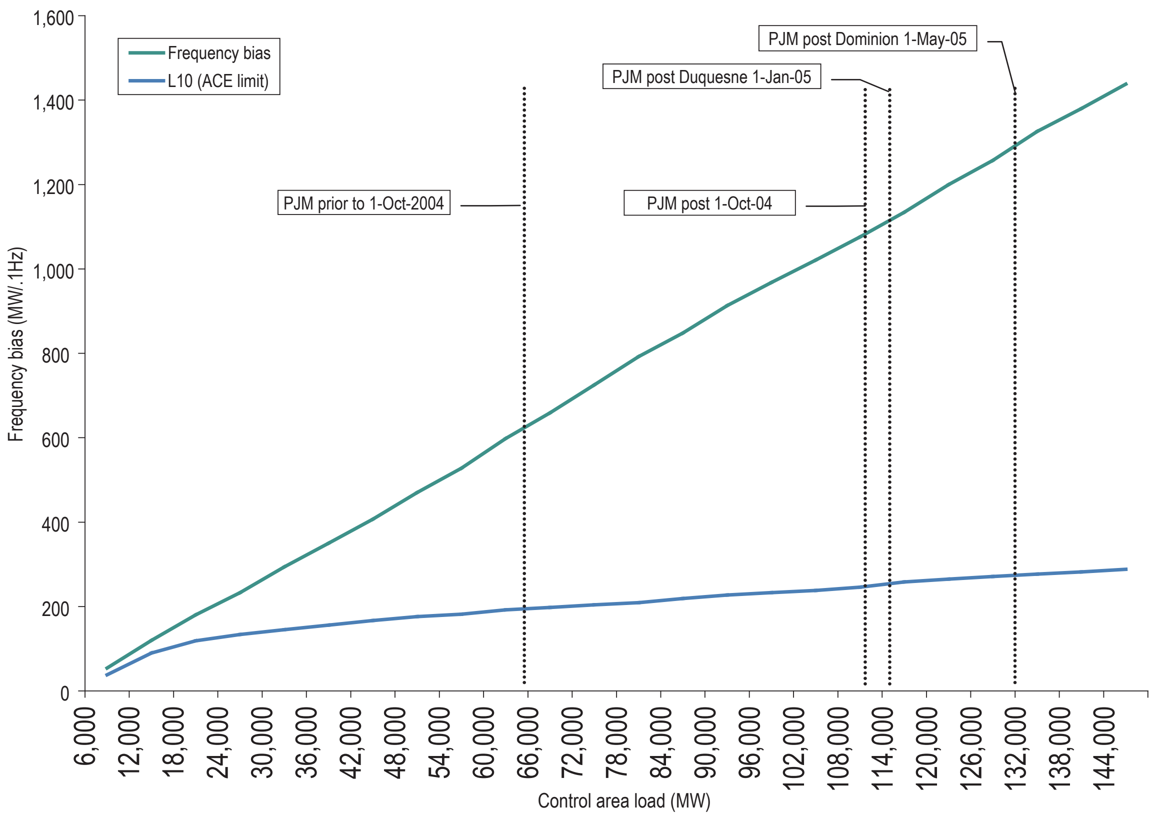
As Figure F-1 shows, PJM's performance relative to both the CPS1 and CPS2 metrics was acceptable in 2005. While PJM passed the CPS performance standard in 2005, PJM's performance with respect to these metrics remains an area of concern. Figure F-1 shows that CPS1 and CPS2 scores for 2005 are generally lower than they were in 2004 and generally lower since Dominion integration (Phase 5) on May 1, 2005. CPS1 and CPS2 standards are pass/fail so this decline is not a problem as long as PJM meets the CPS1 and CPS2 control standards.

Figure F-1 - PJM CPS1 and CPS2 performance: Calendar years 2002 to 2005



PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 standard requires balancing frequency on a monthly running-average basis. Meeting the CPS2 standard requires balancing ACE over 10-minute intervals throughout the day. As control area size (measured by load) grows, frequency bias grows linearly, while L10 (the CPS2 pass/fail standard) grows at an increasingly smaller rate. (See Figure F-2.) For this reason, the integration of external control areas into PJM requires PJM to balance ACE to a standard which grows tighter with control area growth. Furthermore the ACE control standard (CPS2) can sometimes be in conflict with the need to balance frequency over time.

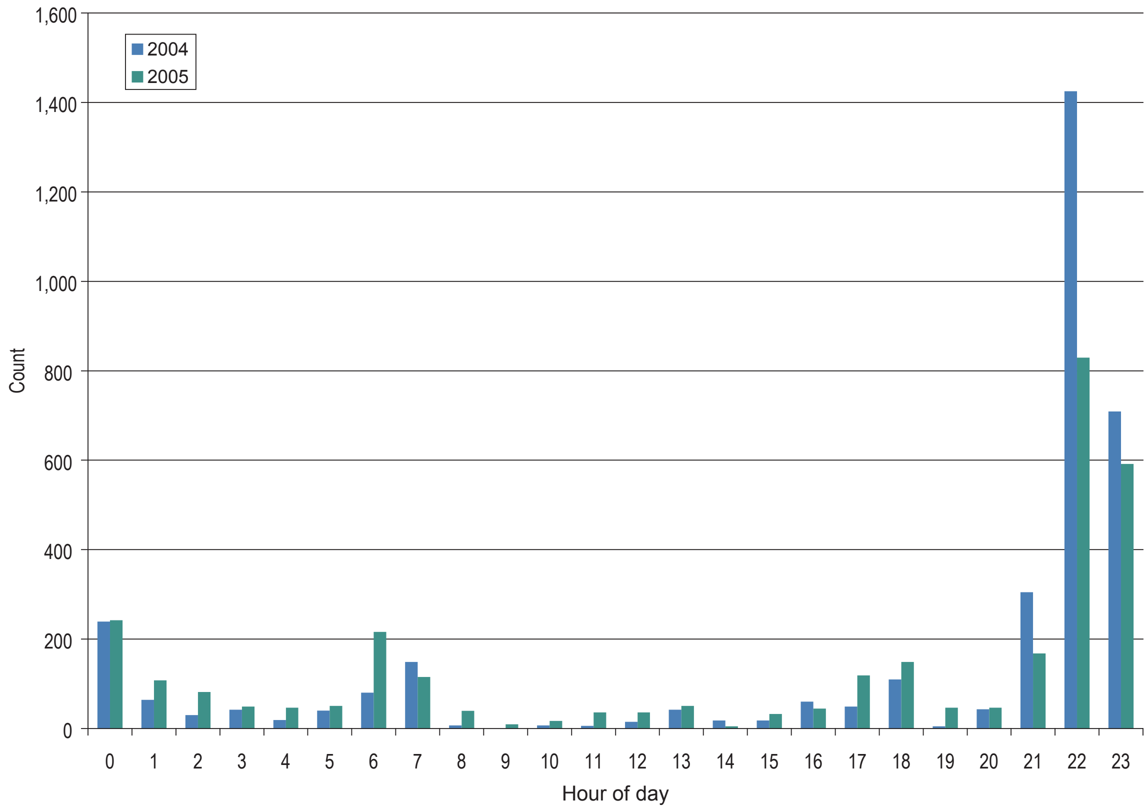
Figure F-2 - Frequency bias and CPS2 ACE limit (L10) as a function of control area size: Calendar years 2003 through 2005



These issues have made CPS2 less reflective of true grid reliability and more an issue of compliance. The CPS2 standard has been under discussion at NERC over the past two years. PJM is participating in discussions with NERC to solve these problems and to find a new measure that is better aligned with grid reliability.

Other metrics that directly measure frequency show improvement in 2005 over 2004. For example, the monthly average number of frequency excursions greater than 0.05 Hz above scheduled frequency was 290 in 2004 and 260 in 2005. The average duration of these frequency disturbances was 23 seconds in 2004 and 20 seconds in 2005. Figure F-3 illustrates that the number of high frequency excursions has gone down in 2005, and that those excursions have occurred primarily between 2100 EPT and 0000 EPT, and between 0600 EPT and 0700 EPT.

Figure F-3 - High frequency excursions above 0.05 Hz (By hour of day): Calendar years 2004 through 2005



ACE is controlled by PJM's regulation AGC signal, which is updated every four seconds. ACE is particularly difficult to control during times of rapid change in load. CPS2 scores were lower in 2005 than they were in 2004. Unlike 2004, however, in 2005 PJM did not have any monthly CPS2 violations (below 90 percent).

The majority of PJM's CPS2 violations in 2005 occurred between 0600 EPT and 0700 EPT and 2100 EPT and 0000 EPT. It is during these hours when many of the traditional dispatch problems occur. Among these problems are: many peak-hour energy contracts terminate at approximately the same time (2300 EPT) and start at 0600 EPT; load (demand) picks up sharply at 0600 EPT and falls off sharply at 2300 EPT; pumped storage units often switch from generation to load (pumping) at the top of hours 2100 EPT through 0000 EPT.

A particularly acute problem can occur when PJM's frequency deviates from its schedule and neighboring control areas also deviate in the same direction. In such a situation, the same AGC response corrects frequency and tie line error at different rates, making it hard to balance both. Such an event occurred on October 4, 2005, just after 2300 EPT. An unusually severe tie line mismatch between scheduled and actual values together with a low frequency excursion sent ACE to -1,700 MW. PJM dispatchers called a 100 percent spin event and ACE was recovered in approximately seven minutes. This event resulted in only one CPS2 violation. (There was, however, a second CPS2 violation 10 minutes later as a result of an over-correction.) October 4, 2005, was an unusually difficult day with 19 CPS2 violations and a CPS2 score of 86.7 percent (90 percent is passing).

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.

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, taken offline, 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. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market and that are not out of service, committed or fully committed to provide energy. Owners of units that have entered offers into the PJM Market User Interface system have the right to set themselves to "unavailable" for regulation for the day, or for a specific hour or set of hours and also have the right to change the amount of regulation MW offered in each hour. Unit owners do not have the right 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 spinning and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 spinning required, to develop regulation and spinning supply curves, to assign regulation and spinning 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:

    1. daily or hourly unavailable units;

    2. 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);

    3. units which are self-scheduled or assigned spinning;

    4. 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);

    5. PJM dispatchers can deselect units from SPREGO 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 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 cost schedule. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. Units are assigned in order of price from the lowest price until the amount of required regulation has been assigned.

- **Regulation Assigned.** Units that are assigned regulation and spinning are expected to provide regulation and spinning for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reasons of reliability 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.

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

The procedure for prorating ARRs when transmission capability limits the amount of ARRs that can be allocated is illustrated here, as is the establishment of ARR target allocations and credits through the Annual FTR Auction.

ARR Prorating Procedure Illustration

Table G-1 provides an illustration 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-1 - 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
Sum			400	175	250	100

The equation would be solved for each request as follows:

Individual *pro rata* MW = (Line capability) * (Individual requested MW / Total requested MW) * (1 / per MW effect on line)

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 *pro rata*, 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 Illustration

Table G-2 illustrates 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 ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies that occur in the hourly Day-Ahead Energy Market.

Table G-2 - 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			$400		$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 – 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 spinning.
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 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.
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 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 Markets	All markets where PJM members can trade capacity.
Capacity queue	A collection of RTEP process 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 Tariff and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Decrement bids (DEC)	Financial offers to purchase specified amounts of MW in the Day-Ahead Energy Market at, or above, a given price.
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 the PJM Office of the Interconnection.
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.
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 (EFORd)	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.
Equivalent forced outage factor (EFOF)	The equivalent forced outage factor is the proportion of hours in a year that a unit is unavailable due to forced outages.
Equivalent maintenance outage factor (EMOF)	The equivalent maintenance outage factor is the proportion of hours in a year that a unit is unavailable due to 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 due to 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 an LSE's unforced capacity exceeds its accounted-for obligation. The term is referred to as "Accounted-for Excess" in the "Definitions and Acronyms Manual" (Manual 35).
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 markets.
Lost opportunity cost (LOC)	The difference in net compensation from the Energy Market between what a unit receives when providing regulation or spinning reserve and what it would have received for providing energy output.
Mandatory interruptible load (MIL)	MIL is retail customer load in ComEd that can be interrupted at the request of PJM. PJM members commit to reduce load by a fixed MW amount or to a certain MW load or to initiate cycling of end-use equipment when called upon by PJM. The account of the LSE which nominated the customer's load drop is credited the MW amount committed. The credit can either be traded or used to meet the member's capacity obligation. Performance is measured, and penalties are charged for under compliance and payments are made for over compliance.
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 the PJM Office of the Interconnection. 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.
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.
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.

Min gen	An emergency declaration for periods of light load.[1]
Monthly CCMs	The capacity credits cleared each month through the PJM Monthly Capacity Credit Markets (CCMs).
Multimonthly CCMs	The capacity credits cleared through PJM Multimonthly Capacity Credit Markets (CCMs).
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.
North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.
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.

1 See PJM Emergency Operations Manual, Section 13, Section 2, pp. 22-27.

PJM member	Any entity that has completed an application and satisfies the requirements of PJM to conduct business with the PJM Office of the Interconnection, 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 Planning (RTEP) Process	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.
Selective catalytic reduction (SCR)	NO_x 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.
Spinning 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. During system restoration, customer load may be classified as spinning reserve.
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.
System lambda	The cost to the PJM system of generating the next unit of output.
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.
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 = T_d – (0.55 – 0.55RH) * (T_d - 58) where T_d 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 I – 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 Rights
ASA	Ancillary service area
ATC	Available transfer capability
AU	Associated unit
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
Btu	British thermal unit
C&I	Commercial and industrial customers
CAISO	California Independent System Operator
CCM	Capacity Credit Market
CC	Combined cycle
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
ComEd	The Commonwealth Edison Company
CP	Pulverized coal-fired generator
CPL	Carolina Power & Light Company
CPS	Control performance standard
CT	Combustion turbine
DAY	The Dayton Power & Light Company
DCS	Disturbance control standard
DEC	Decrement bids
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 Rights
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 offers
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
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

MAIN	Mid-America Interconnected Network, Inc.
MAAC	Mid-Atlantic Area Council
MACRS	Modified accelerated cost recovery schedule
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
MP	Market participant
MMU	PJM Market Monitoring Unit
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	PJM Operating Agreement
OASIS	Open Access Same-Time Information System
OATT	PJM Open Access Transmission Tariff
OC	Opportunity cost
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
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/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/MEC	The interface between PJM and MidAmerican Electric 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
PSEG	Public Service Electric and Gas Company
PSN	PSEG north
PSNC	PSEG northcentral

QIL	Qualified interruptible load
RAA	Reliability Assurance Agreement among Load-Serving Entities in the PJM Control Area
RECO	Rockland Electric Company zone
RMCP	Regulation market-clearing price
RPM	Reliability Pricing Model
RSI	Residual supply index
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Planning
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
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
SPREGO	Spinning and regulation optimizer (market-clearing software)
SPS	Special protection scheme
SRMCP	Spinning reserve market-clearing price
STD	Standard deviation

STE	Short-term emergency
SVC	Static Var compensator
THI	Temperature-humidity index
TLR	Transmission loading relief
TVA	Tennessee Valley Authority
UGI	UGI Utilities, Inc.
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VOM	Variable operation and maintenance expense
WEC	Wisconsin Energy Corporation

ERRATA

If this sheet is bound with the report and not affixed to the errata page, then relevant changes are reflected in the Report. Otherwise, the corrections described below can be found in the online version currently available at http://www.pjm.com/markets/market-monitor/som.html.

Pages 29 and 116 - The third bullet in “Existing and Planned Generation” has been changed.

Page 136 - Figure 3-5 and associated text have been changed.

Page 137 - Table 3-16 has been changed.

Please address comments or questions to: bowrij@pjm.com.