2003 State of the Market

Market Monitoring Unit

March 4, 2004

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 *2003 State of the Market Report* is the sixth such annual report. This report is submitted to the Board of Managers of the PJM Interconnection, L.L.C. 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 (FERC) per the Commission's Order in PJM Interconnection, L.L.C., 96 FERC 61,061 (2001):

> "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."

Errata

PJM 2003 State of the Market Report

If this sheet is bound with the Report at page 2, 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.

Page 101
Figure 3-7: First printing had an incorrect legend

Page 198
Figure 7-8: First printing had an incorrect graph

Page 200
Missing from first printing

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Last updated 10 March 2004

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Section 1 – Introduction to the State of the Market 2003

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electricity market comprising generating capacity of more than 76,000 megawatts (MW) and about 250 market buyers, sellers and traders of electricity in a region including more than 25 million people in all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.[1]

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 nodal energy pricing with market-clearing prices based on offers at cost on April 1, 1998, and nodal, market-clearing prices based on competitive offers on April 1, 1999. Daily Capacity Markets were introduced on January 1, 1999, and Monthly and Multimonthly Capacity Markets introduced in mid-1999. PJM implemented an auction-based FTR Market on May 1, 1999. It 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.[2]

This report assesses the competitiveness of the Markets managed by PJM during 2003, including market structure and market performance. This report was prepared by and reflects the analysis of PJM's Market Monitoring Unit (MMU).

Conclusions

The MMU concludes that in 2003:

- The Energy Market results were competitive;
- The Capacity Market results in the PJM Mid-Atlantic Region were competitive;
- The Capacity Market results in the PJM Western Region were not based on a functioning competitive market in the PJM Western Region;
- The Regulation Market results were competitive;
- The Spinning Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

The MMU also concludes:

- There are potential threats to competition in the Energy, Capacity, Regulation and Spinning Reserve Markets that require ongoing scrutiny;
- Market power in the Capacity Markets remains a serious concern given the extreme inelasticity of demand and high levels of concentration. Market power is structurally endemic to PJM Capacity Markets and any redesign of Capacity Markets must address market power;
- The rule changes governing interface pricing have addressed significant sources of market power. Nonetheless, market participants have the ability to exercise market power at the interfaces between PJM and external regions under some conditions. Continued scrutiny of the interfaces between LMP and contract path based markets is required;
- Market participants possess some ability to exercise market power in PJM Energy Markets under certain conditions; and
- Market participants possess some ability to exercise market power in PJM Ancillary Service Markets under some conditions.

1 See Appendix A, "PJM Service Area," for map.
2 See also Appendix B, "Historic Developments in PJM Markets."

Recommendations

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

- Evaluation of additional actions to increase demand-side responsiveness to price in both Energy and Capacity Markets and actions to address institutional issues which may inhibit the evolution of demand-side price response;
- Continued development of an integrated approach to economic planning that evaluates the costs and benefits of identified alternative investments in areas where investments in transmission expansion, generation or demand-side resources would relieve congestion, especially where that congestion may enhance generator market power and where such investments are needed to support competition;
- Continued enhancements to the PJM Capacity Market to stimulate competition, adoption of a single capacity market design and incorporation of explicit market power mitigation rules to limit the ability to exercise market power in the Capacity Market;
- Development of a joint redispatch protocol with the NYISO to address loop flow issues and interface pricing issues;
- Continued development of more sophisticated methods for developing appropriate prices for transactions between PJM and external, non-market control areas to provide incentives to competitive behavior and limit loop flows;
- Retention of the $1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power;
- Retention and enhancement of local market power mitigation rules to prevent the exercise of local market power while ensuring appropriate economic signals when investment is required;
- Review and appropriate modification of PJM's rules governing operating reserve payments to generators both to reduce gaming incentives and to enhance compensation under certain conditions;
- Review and appropriate modification of rules governing the reporting and verification of unit outages; and
- Based on the experience of the MMU during its fifth year and its analysis of the PJM Markets, the MMU does not recommend any additional changes to the Market Monitoring Unit or to the Market Monitoring Plan at this time.

Energy Market

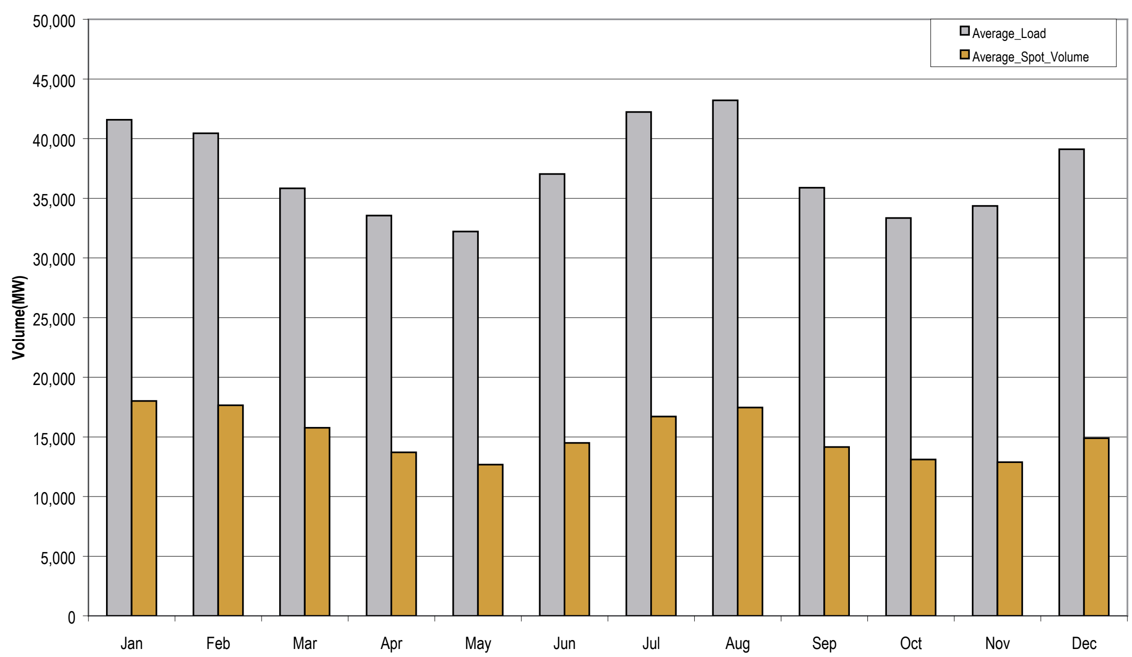
Energy Market Design

In PJM, market participants wishing to buy and sell energy have multiple options. Market participants decide whether to meet their energy needs through self-supply, bilateral purchases from generation owners or market intermediaries, through the Day-Ahead Market or the Real-Time Balancing Market. Energy purchases can be made over any timeframe from instantaneous Real-Time Balancing Market purchases to long-term, multiyear bilateral contracts. Purchases may be made from generation located within or outside PJM. Market participants also decide whether and how to sell the output of their generation assets. Generation owners can sell their output within PJM or outside it and can use generation to meet their own loads, to sell into the spot market or to sell bilaterally. Generation owners can sell their output over any timeframe from the PJM Real-Time Energy Market to multiyear bilateral arrangements. Market participants can use increment and decrement bids in the Day-Ahead Market to hedge positions or to arbitrage expected price differences between markets.

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 Balancing 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. The PJM Market Monitoring Unit (MMU) analyzed measures of energy market structure and performance for 2003, including market size, concentration, residual supplier index, price-cost markup, net revenue and prices. The MMU concludes that, despite ongoing concerns about market structure, the PJM Energy Market results were competitive in 2003.

For 2003 Real-Time Spot Market activity averaged 16,194 MW during peak periods and 14,177 MW during off-peak periods, or 40 percent of average loads for all hours (Figure 1-1). In the Day-Ahead Market, spot market activity averaged 14,394 MW on peak and 12,887 MW off peak, or 31 percent of average loads for all hours. Spot market activity as a proportion of load in the Real-Time Market increased in 2003 over 2002. More participants in 2003 relied on the PJM Spot Market rather than self-supply or bilateral arrangements to clear their energy transactions. Such reliance on the Spot Market increases the importance of PJM implementing appropriate credit protections, consistent with those available to participants in bilateral transactions.

Figure 1-1 2003 PJM Average Hourly Load and Spot Market Volume



Overview

Market Structure

- **Market Size.** During the 12-month period from October 1, 2002, to September 30, 2003, approximately 5,000 MW of additional generation of which 300 MW of upgrades to existing generation and 4,700 MW of new generation were added in PJM.[3] These increases were offset in part by the derating of 100 MW of generation and the retirement of 100 MW of existing facilities. The new generation was entirely gas-fired, with most of it based on combined-cycle technology. Upgrades to existing generation included approximately 150 MW in hydroelectric, 100 MW in gas-fired and 50 MW in nuclear facilities. During this same period, approximately 100 MW of gas-fired generation was derated and another 100 MW of gas-fired generation was retired. The net result of the addition of new combined-cycle units was a flattening of the middle portion of the PJM aggregate supply curve. The PJM system peak load in 2003 was approximately 2,300 MW less than it had been in 2002.

- **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 suggest larger numbers of sellers splitting market sales more equally. Analysis of the PJM Energy Market indicates moderate market concentration overall, but high levels of concentration in the intermediate and peaking segments of the supply curve. Further, specific geographic areas of PJM exhibit moderate to high concentration that may be problematic when transmission constraints exist. No evidence exists, however, that market power was exercised in these areas during 2003, primarily because of generators' obligations to serve load. If those obligations were to change, significant market-power-related risk would exist.

- **Pivotal Suppliers.** A generation owner is pivotal if the output of the owner's generation facilities is required in order to meet market demand. When a generation owner is pivotal, it has the ability to affect market price. The residual supply index (RSI) is a measure of the extent to which generation owners are pivotal suppliers. When the RSI is less than 1.00, a generation owner is pivotal. The RSI results are consistent with the conclusion that the PJM Energy Market results were competitive in both 2002 and 2003, with an average RSI of 1.57 and 1.66, respectively. In 2003, a generation owner in the PJM Energy Market was pivotal for only six hours, less than 1 percent of all hours during the year. This represents a reduction in pivotal hours from 2002, when a generation owner was pivotal in the Energy Market for 87 hours, or approximately 1 percent of all hours

- **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 severely underdeveloped. This underdevelopment is one of the basic reasons for maintaining an offer cap in PJM and other wholesale power markets. Total demand-side resources available in PJM during 2003 were 1,207 MW of active load management, 659 MW from the Emergency Load-Response Program and 724 MW from the Economic Load-Response Program. There were 445 MW enrolled in both the Load-Response Program and in active load management. The 4,918 MW in total DSR resources, including additional programs reported by PJM customers in response to a survey, were approximately 8.0 percent of peak demand.

Market Performance

- **Price-Cost Markup.** Price-cost markups are a measure of market power. The price-cost markup index is defined here as the difference between price and marginal cost, divided by price, which is load weighted to account for congestion and normalized. Overall, the data on the price-cost markup are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2003.

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

- **Net Revenue.** Net revenue is an indicator of generation investment profitability. It is thus a measure of incentives to add generation to serve PJM Markets and a significant measure of overall market performance. Net revenue measures the contribution to capital cost that generators receive from PJM Energy and Capacity Markets, Ancillary Service Markets and operating reserve payments. In 2003, net revenue from these sources would not have covered fixed costs for a peaking unit with variable operating costs between $70 and $75 per MWh[4] if it had run during all profitable hours. Market results vary from year to year; those for 2003 reflected higher average energy and lower capacity market prices than those for 2002.

- **Energy Market Prices.** PJM's locational marginal prices reflect market structure and the conduct of individual participants. 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 2002 to 2003. The simple, hourly average system locational marginal price (LMP) was 35.2 percent higher in 2003 than in 2002, $38.27 per MWh versus $28.30 per MWh. When hourly load levels are reflected, the load-weighted LMP of $41.23 per MWh in 2003 was 30.5 percent higher than in 2002. However, when increased fuel costs are accounted for, the average, fuel-cost-adjusted, load-weighted LMP was 9.5 percent lower in 2003 than in 2002, $28.60 per MWh compared to $31.60 per MWh.

  PJM average real-time energy market prices increased in 2003 over 2002 for several reasons, including significantly increased fuel costs and increased demand during the first quarter of 2003. These changed fundamentals led to higher prices during normal system conditions. PJM did not experience extreme demand conditions during 2003. While LMPs were higher overall, LMP exceeded $150 per MWh for only 11 hours during all of 2003 and was greater than $200 per MWh for only one hour with a maximum of $210.83 per MWh.

The Energy Market results for 2003 reflected supply-demand fundamentals. While Energy Market results were competitive, analysis of the Energy Market has identified a number of concerns regarding market structure that could affect competitive market results when markets are tighter, including:

- The relatively high levels of concentration in the intermediate and peaking portions of the aggregate supply curve;
- The relatively high levels of concentration in markets defined by transmission constraints; and
- The relatively high levels of concentration in the ownership of marginal units.

Mitigation

- **Offer-Capping Statistics.** PJM rules limiting exercise of market power provide that PJM can offer-cap units when they would otherwise have the ability to exercise local market power. Offer-capping levels have declined since 2001. Offer-capping does not have a significant negative impact on unit net revenues.

4 The $70 to $75 per MWh variable operating cost reflects 2003 average natural gas costs and the heat rate of a new peaking unit.

Operating Reserves

- Operating reserve payments are made to resource owners under specified conditions in order to ensure that units are not required to operate for PJM at a loss. These payments provide an incentive to generation owners to offer their energy to the PJM market at marginal cost and to operate their units at the direction of PJM dispatchers. If a unit is selected to operate in the PJM Day-Ahead Market on the basis of its offer and the revenues in the Energy Market are insufficient to cover all the components of that unit's offer, including start-up and no-load offers, operating reserve payments ensure that all offer components are covered.

- Between 2002 and 2003, operating reserve payments rose by approximately $85 million from approximately $189 million to $274 million for a 45 percent increase from 2002 to 2003. Operating reserve payments as a percentage of total PJM billings remained constant at 4 percent in 2002 and 2003.

- A relatively small number of generation owners accounted for a substantial proportion of total operating reserve payments in each year from 2001 through 2003. In 2002, the top-10 units that received operating reserve payments represented 32.0 percent of total operating reserve payments and in 2003 the share of the top-10 units increased to 39.2 percent of the system total.

- The MMU will continue to examine the various factors underlying operating reserve payments. The reasons that a relatively small number of generation owners account for a substantial proportion of total operating reserve payments will be examined. The role of unit-specific, price-cost markups will be examined. The role of restrictive operating parameters will be examined. Finally, the role of PJM operations in contributing to overall operating reserve payment levels and to operating reserve payments to the top-10 units will be examined to ensure that PJM is operating in an efficient manner. The MMU will also examine the other rules governing operating reserve payments, including the requirement that they be based on a 24-hour average of LMP revenues and offers.

Interchange Transactions

PJM has interfaces with four contiguous, external regions. These interfaces are the seams between PJM and other regions. PJM market participants import energy from, and export energy to, external regions on a continuous basis.[5] These transactions may fulfill long-term or short-term bilateral contracts or take advantage of price differentials.

At the end of 2003, PJM's four interfaces had five interface pricing points: PJM/New York Independent System Operator (PJM/NYIS), PJM/FirstEnergy Corp. (PJM/FE), PJM/Duquesne Light Company (PJM/DLCO), PJM/AEPVP, and PJM/Ontario Independent Electricity Market Operator (PJM/IMO). The first three were in place at the beginning of the year; the last two were created in 2003 to help manage loop flow issues. In March, PJM/AEPVP was formed by combining the PJM/American Electric Power Company, Inc. (PJM/AEP) and PJM/Virginia Electric and Power Company (PJM/VAP) interfaces. On August 1, 2003, PJM/IMO was created.

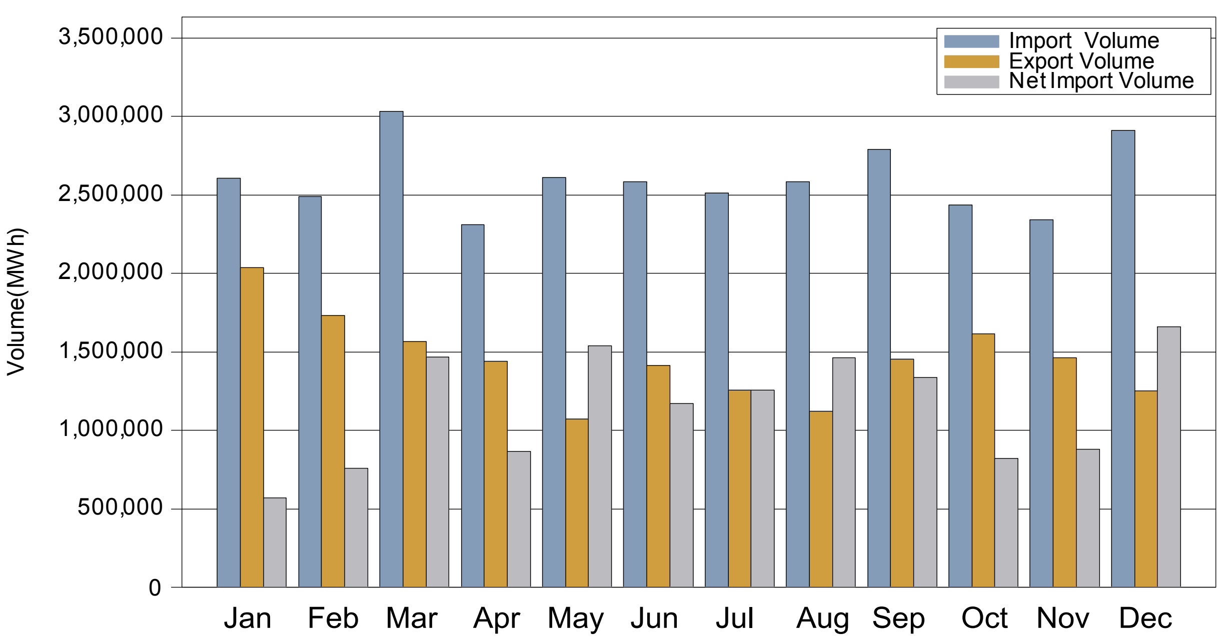
Overview

Transaction Activity

- **Aggregate Imports and Exports.** For each month of 2003, PJM was a net importer of power, averaging 1.15 million MWh of net imports per month, or slightly less than the year 2002 level of 1.23 million MWh. The 2003 average monthly gross import volume of 2.60 million MWh also represented a slight decline from 2.67 million MWh in 2002. Gross exports changed little in 2003 from 2002, averaging 1.45 million MWh in 2003 and 1.44 million MWh in 2002.

- **Interface Imports and Exports.** During 2003, net imports at two interfaces accounted for 96 percent of total net imports. Net imports at the PJM/AEPVP interface were 49 percent and net imports at the PJM/FE interface were 47 percent. Net exports occurred only at the PJM/NYIS interface.

Figure 1-2 PJM Imports and Exports: 2003



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5 These transactions occur primarily in the Real-Time Energy Market. Approximately 82 percent of total gross imports and 84 percent of gross exports take place in the Real-Time Energy Market without corresponding day-ahead transactions.

Interchange Transaction Issues

- **Loop Flow.** Loop flow results when the transmission contract path for energy transactions does not match the actual path of energy flows on the transmission system. Loop flows can arise from transactions scheduled into, out of or around the PJM system. Outside of PJM's LMP-based Energy Market, energy is scheduled and paid for based on contract path while the actual associated energy deliveries flow on the path of least resistance. Loop flows can result when a transaction is scheduled between two external control areas and some or all of the actual flows occur at PJM interfaces. Loop flows can also result when transactions are scheduled into or out of PJM on one interface, but actually flow on another. Although total PJM scheduled and actual flows were approximately equal in 2003, such was not the case for each individual interface.

- **Interface Pricing Issues.** PJM experienced continuing loop flow issues during the winter of 2002 and early in 2003 when transactions scheduled for delivery at the PJM/VAP interface actually flowed at the PJM/AEP interface. When the issue first emerged in the summer of 2002, it resulted from actions designed to exploit differences between the way in which PJM locational marginal prices (LMPs) were determined and the artificial contract paths that existed west and south of PJM. To address that problem, PJM issued updated rules in July 2002. Ongoing investigation into loop flows and circulation impacting PJM indicated, however, that further modifications were needed to the pricing rules governing external transactions. Specifically, a continuing discrepancy between scheduled and actual power flows at the PJM/AEP and the PJM/VAP interfaces worsened, particularly during the off-peak hours, late in 2002 and continued into early 2003 despite the July 2002 rule changes.[6] To address this issue, on February 24, 2003, the PJM Market Monitoring Unit (MMU) notified market participants of a rule change governing interface pricing for transactions, scheduled to and from specific control areas. The PJM/AEP and PJM/VAP interfaces were combined into a new, single, PJM/AEPVP interface. The document, "Mapping for External Transaction Pricing," was developed; it assigned specific control areas an import and export price point regardless of contract path.[7] Additionally, on August 1, 2003, PJM created the PJM/IMO interface pricing point that is applicable to transactions sourcing/sinking into IMO. This price point was added to address the fact that flows from IMO flow over both the PJM/NYIS and PJM Western Interfaces and, therefore, that neither price was appropriate for such transactions.

- **PJM and New York Transaction Issues.** The relationship between the PJM/NYIS interface price and the New York Independent System Operator (NYISO) PJM Proxy bus price appears to reflect economic fundamentals. The relationship between interface price differentials and power flows between PJM and the NYISO also appears to reflect economic fundamentals. However, both are affected by differences in institutional and operating practices in PJM and NYISO.

6 The July 2002 rule changes had mitigated the magnitude of the recurrence.

7 The language is from the current rule which was updated most recently on February 24, 2003.

Capacity Markets

Capacity Market Design

Each organization serving PJM load must own or acquire capacity resources to meet its respective capacity obligations. Load-serving entities (LSEs) can acquire capacity resources by entering into bilateral agreements or by participating in the PJM-operated Capacity Credit Markets. Collectively, all arrangements by which LSEs acquire capacity are known as the Capacity Market.[8]

The PJM Capacity Credit Market provides a mechanism 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, Monthly and Multimonthly Capacity Credit Markets. The 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.

The PJM Market Monitoring Unit (MMU) recommended in its "2002 State of the Market Report" that the PJM Mid-Atlantic and Western Regions' separate Capacity Credit Markets be combined into a single market with one set of rules. That recommendation was implemented by PJM on June 1, 2003.

Capacity Market Results

The MMU analyzed key measures of PJM Capacity Market structure and performance for 2003, including concentration ratios, prices, outage rates and reliability. The MMU found serious market structure issues, but no exercise of market power during 2003.

The PJM Mid-Atlantic Region's Capacity Market results were competitive during 2003. The PJM Western Region's Capacity Market did not operate in a meaningful way during 2003. There was not a functioning competitive market in the PJM Western Region. Beginning June 1, 2003, the two markets were combined into a single market with rules identical to those that had previously provided the operating framework for the Capacity Market in the PJM Mid-Atlantic Region alone. Inclusion of the PJM Western Region's Capacity Market in a broader capacity market is a positive step. Nonetheless, market power remains a serious concern for the MMU in the Capacity Market.

Market Structure

PJM Mid-Atlantic Region: January through May 2003

- **Supply.** Structural analysis of the PJM Mid-Atlantic Region's Capacity Credit Market found that short-term markets exhibited moderate concentration and long-term markets exhibited high concentration levels in 2003.

- **Demand.** During 2003, the original PJM Mid-Atlantic Region electric utilities and their affiliates accounted for 90 percent of the PJM Mid-Atlantic Region's load obligations.

8 See Appendix E, "Glossary," for definitions of PJM Capacity Credit Market terms..

- **Supply and Demand.** During the first interval[9] of 2003, installed capacity, unforced capacity and obligations grew in the PJM Mid-Atlantic Region. Compared to the same period of 2002, average installed capacity increased by 2,615 MW or 4.3 percent to 64,075 MW, while average unforced capacity rose by 2,467 MW or 4.2 percent to 60,960 MW. Average load obligations climbed by 2,992 MW or 5.3 percent to 59,630 MW, or 1,330 MW less than average unforced capacity. During the first interval, overall Capacity Credit Market transactions increased by nearly 22 percent. Daily Capacity Credit Market volume increased by 112 percent, while Monthly and Multimonthly Capacity Credit Market volume increased by 7.2 percent and 14.2 percent, respectively.

PJM Western Region: January through May 2003

- **Supply.** Structural analysis of the PJM Western Region's Capacity Credit Markets found extremely high concentration levels in the first interval of 2003.

- **Demand.** During the first interval of 2003, the original PJM Western Region electric utility accounted for 96.9 percent of the PJM Western Region's load obligations.

- **Supply and Demand.** In the first interval of 2003, the PJM Western Region's average installed capacity was 10,293 MW and the average available capacity was 8,482 MW. The average capacity obligation was 6,817 MW while the maximum capacity obligation was 9,002. The Capacity Credit Market was effectively not operating in the PJM Western Region during the first interval of 2003.

PJM: June through December 2003

- **Supply.** Structural analysis of the combined PJM Mid-Atlantic and Western Regions' Capacity Credit Markets found that high concentration levels were exhibited during the last two intervals of 2003.

- **Demand.** During the last two intervals of 2003, the original electric utilities in the two regions and their affiliates accounted for 85.8 percent of systemwide PJM load obligations.

- **Supply and Demand.** During the last two intervals of 2003, installed capacity, unforced capacity and obligations grew in PJM with respect to the same time period last year. Compared to the same period of 2002, average installed capacity increased by 4,774 MW or 6.5 percent to 77,728 MW. Average load obligations climbed to 70,203 MW. Overall, Capacity Credit Market transactions increased to 4,740 MW while Daily Capacity Credit Market volume increased to 1,120 MW. Monthly Capacity Credit Market volume decreased to 746 MW, but Multimonthly Capacity Credit Market volume rose to 2,874 MW.[10]

Market Performance

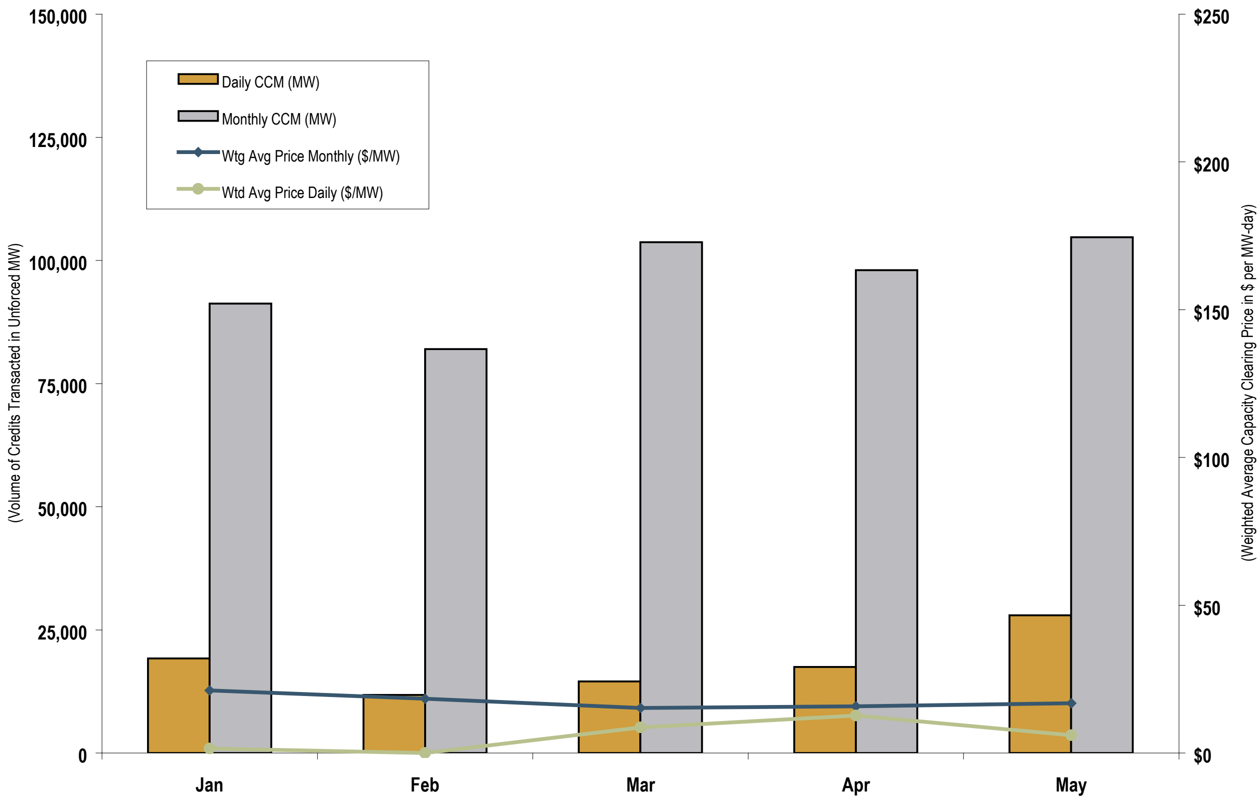
PJM Mid-Atlantic Region: January through May 2003

- **Prices.** Daily Capacity Credit Market prices were low during the first interval of 2003, averaging $6.00 per MW-day. Prices in the monthly and multimonthly markets declined slightly over the interval from $21.14 per MW-day in January to $16.87 per MW-day in May, averaging $17.36 per MW-day for the first interval (Figure 1-3).

9 PJM defines three intervals for PJM 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.

10 Since some of the measures of capacity market supply and demand were in different units for the Mid-Atlantic and Western Regions (e.g. unforced MW for the Mid-Atlantic Region and available MW for the Western Region), these measures cannot be directly compared.

Figure 1-3 PJM Mid-Atlantic Region Daily and Monthly Capacity Credit Market Performance: January through May 2003



PJM Western Region: January through May 2003

- **Prices.** Daily Capacity Market prices averaged $0.02 per MW-day. There were no trades in the monthly and multimonthly markets during 2003.

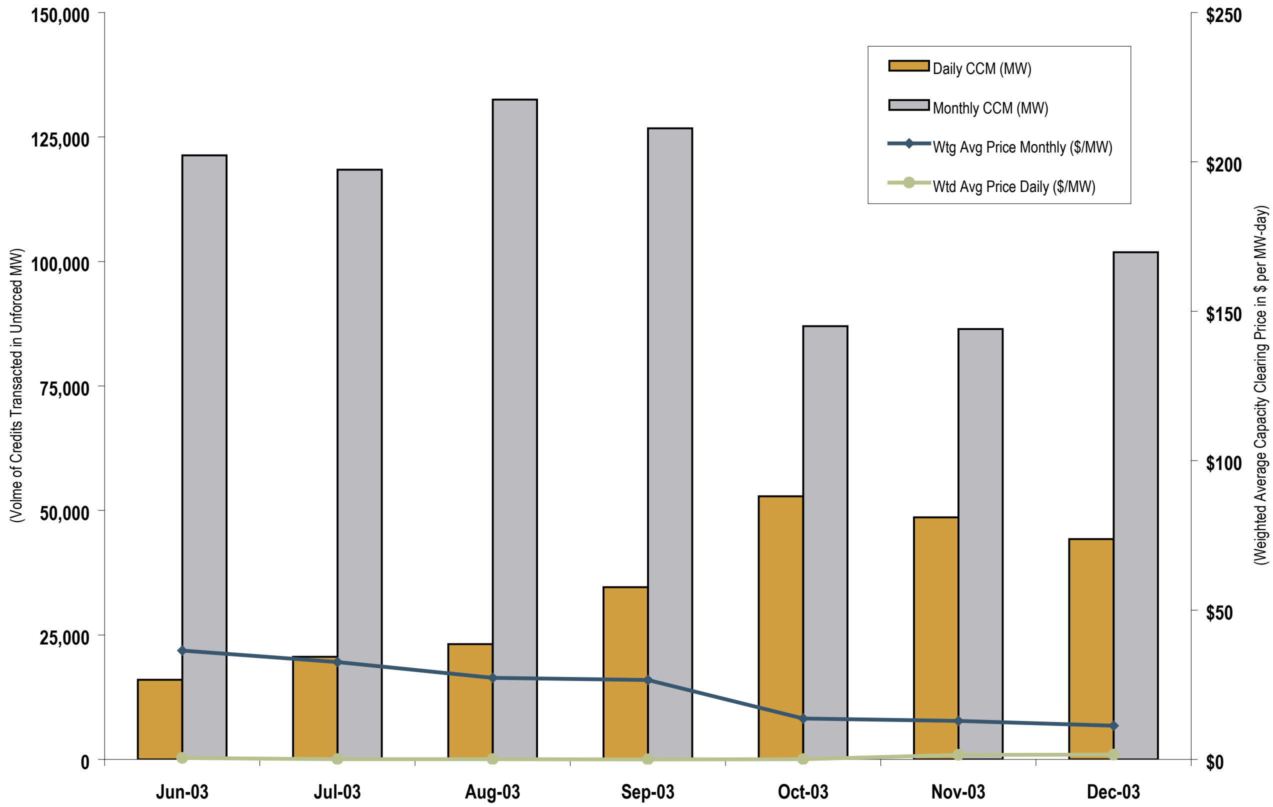
- **Volumes.** There was very little activity in the Capacity Credit Markets during the first interval of 2003. An average 0.15 MW traded in the daily market. Trades occurred on only three separate days. No trades were completed in the monthly or multimonthly markets. One very small 0.1 MW multimonthly trade from 2002 was effective through May 31, 2003.

PJM: June through December 2003

- **Prices.** Daily Capacity Credit Market prices were quite low during the last two intervals of 2003, averaging $0.68 per MW-day. Prices in the monthly and multimonthly markets declined over that period from $36.46 per MW-day in June to $11.26 per MW-day in December, averaging $24.18 per MW-day day (Figure 1-4).

- **Availability.** Between 1996 and 2001, the average PJM forced outage rate (EFORd) trended downward, reaching 4.8 percent in 2001 and then increased to 5.2 percent in 2002 and 7.1 percent in 2003. The increase in EFORd of 1.9 percent from 2002 to 2003 was the result of increased forced outage rates across all unit types.

Figure 1-4 PJM Daily and Monthly Capacity Credit Market Performance: June through December 2003



Given the basic features of Capacity Market structure in both the PJM Mid-Atlantic and the PJM Western Regions, 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 likelihood of the exercise of market power is high. Market power is structurally endemic to PJM Capacity Markets. Supply and demand fundamentals offset these market structure issues in the PJM Mid-Atlantic Region's Capacity Market in 2003, producing competitive results. In the PJM Western Region's Capacity Market, the dominance of a single supplier and the extremely small load levels served by independent LSEs meant that there was not a functioning competitive market in the PJM Western Region prior to the inclusion of the PJM Western Region in the PJM Capacity Market.

Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888.[11] Of these, PJM currently provides both regulation and spinning through market-based mechanisms.

Regulation matches generation with very short-term increases and decreases in load by moving the output of selected generators up and down via an automatic control signal. 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 and must be synchronized to the system and capable of providing output within 10 minutes.

The Regulation Market was introduced on June 1, 2000, and modified on December 1, 2002, at the same time the Spinning Reserve Market was implemented. Both the Regulation Market and the Spinning Reserve Market are cleared on a real-time basis.

Overview

The PJM Market Monitoring Unit (MMU) has reviewed structure and performance indicators for both the Regulation Market and the Spinning Reserve Market. The MMU concludes that both markets functioned effectively and produced competitive results in 2003.

Both the Regulation Market and the Spinning Reserve Market operate separately in the PJM Mid-Atlantic Region and in the PJM Western Region.[12] The market analysis treats each Regulation Market and each Spinning Reserve Market separately. Both the Regulation Market and the Spinning Reserve Market in the PJM Western Region are cost-based and are not competitive markets as there is only one supplier of regulation and one supplier of spinning reserve in the PJM Western Region. The Regulation Market and the Spinning Reserve Market in the PJM Mid-Atlantic Region are both based on a market-clearing price. All suppliers are paid the market price which is determined by demand and the offer of the marginal supplier. In the PJM Western Region, regulation and spinning reserve are compensated based directly on the costs of the specific units offering to provide the respective ancillary services, including opportunity costs.

Regulation Market Results

The MMU has reviewed structure and performance indicators for the Regulation Market and concludes that the Regulation Market functioned effectively and produced competitive results in 2003 (Figure 1-5).

Regulation Market Structure

- **Concentration of Ownership**. In 2003, the PJM Regulation Market saw an increase in concentration levels, although they generally remained moderate and concerns about market concentration continued to be offset by the level of available regulation supply relative to demand for the service. In the PJM Western Region, there was only one supplier.

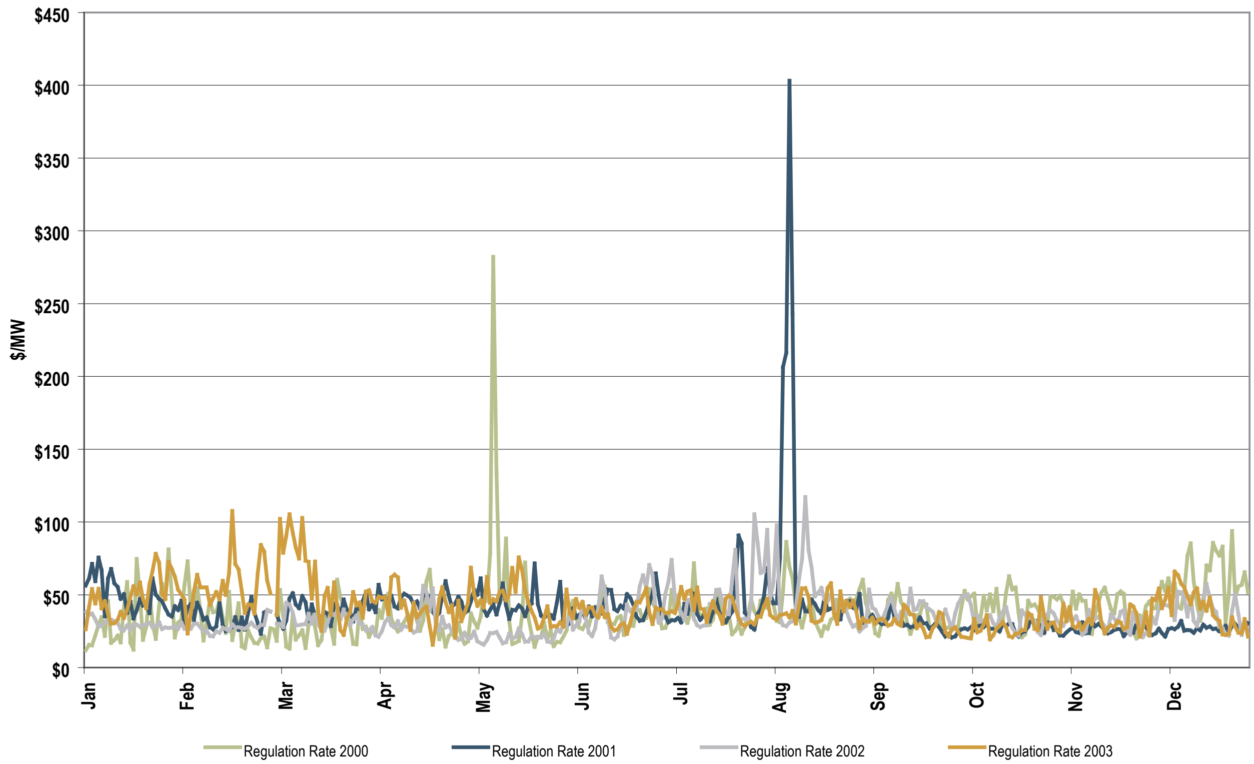
Regulation Market Performance

- **Price.** The market price of regulation exhibited the expected relationship to changes in demand and the cost of supply. Average price per MW associated with meeting PJM's demand for regulation during 2003 increased by about $5 per MW, or about 14 percent over 2002. The average cost per MW in the PJM Mid-Atlantic Region was about $45 per MW, and the average cost per MW in the PJM Western Region was about $25 per MW (Figure 1-5).

11 See FERC "Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," April 24, 1996.

12 The PJM Mid-Atlantic Region is in the MAAC NERC region and the PJM Western Region is in the ECAR NERC region. MAAC and ECAR have different reliability requirements for the two services. These requirements are documented in the business rules for each market, located in the "PJM Manual for Scheduling Operations, M-11."

Figure 1-5 Daily Regulation Cost per MW



- **Availability.** Introduction of a market in regulation resulted in significant improvement in system regulation performance during 2001 and the first part of 2002. System regulation performance declined after the addition of the PJM Western Region in April 2002. However, system regulation performance was stable from December 2002 through December 2003 after the implementation of the new Regulation Market.

Spinning Reserve Market Results

The MMU has reviewed structure and performance indicators for the Spinning Reserve Market and concludes that the Spinning Market functioned effectively and produced competitive results in 2003.

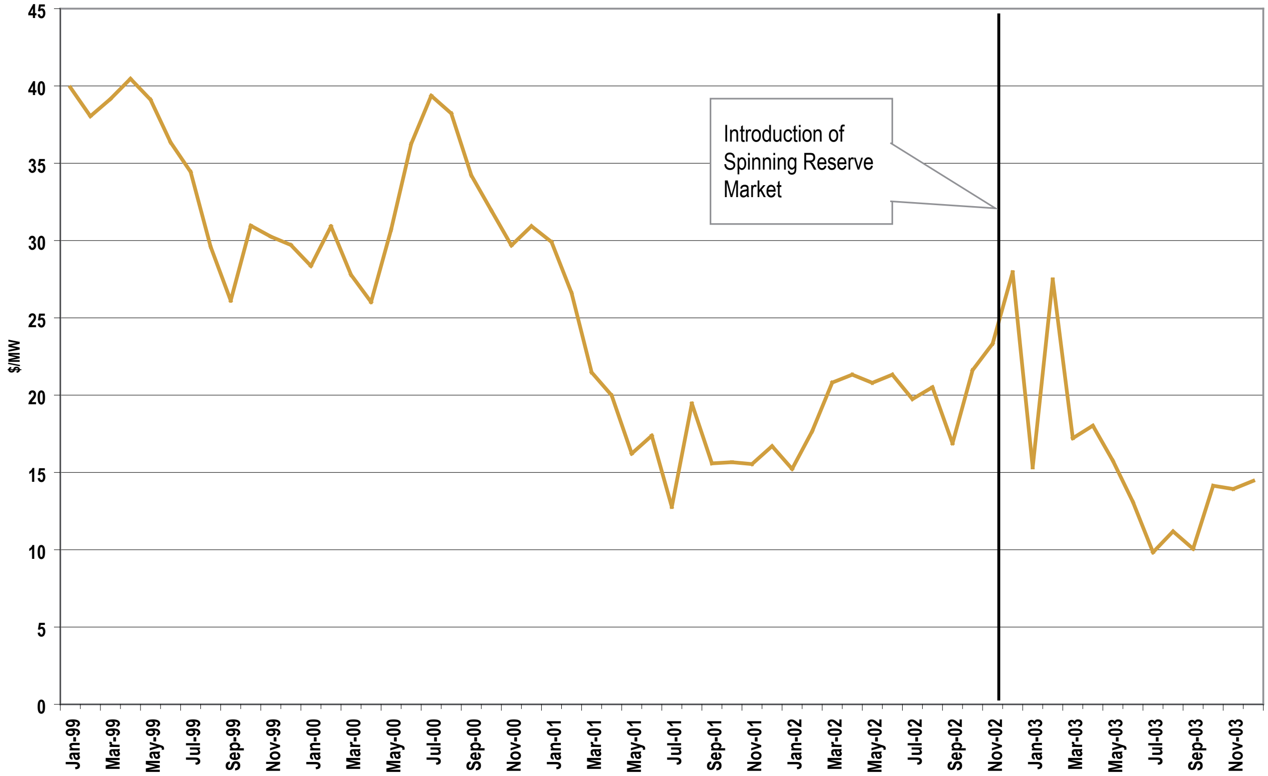
Spinning Reserve Market Structure

- **Concentration of Ownership.** In 2003, concentration was high in the Tier 2 Spinning Reserve Market. The average HHI for the PJM Mid-Atlantic Region in 2003 was 2544. In the PJM Western Region there was only one supplier.

Spinning Market Performance

- **Price.** Average cost per MW associated with meeting PJM's system demand for spinning reserve decreased about \$6 per MW, or about 29 percent, in 2003 over 2002. Average cost per MW in the PJM Mid-Atlantic Region was about \$15 per MW, and the average cost per MW in the PJM Western Region was about \$43 per MW (Figure 1-6).

Figure 1-6 Total Spinning Credits per MW



Congestion

Congestion occurs when available, low-cost energy cannot be delivered to all loads because of limited transmission facilities. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units must be dispatched to meet that load.[13] The result is that the price of energy in the constrained area is higher than elsewhere and congestion exists. Locational marginal prices (LMPs) reflect the cost 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.

Overview

- **Total Congestion.** Congestion costs were approximately $499 million in 2003, a 16 percent increase from $430 million in 2002. Congestion costs have ranged from 6 to 9 percent of annual total PJM billings since 2000. Congestion costs declined from 9 percent of total billings in 2002 to 7 percent of total billings in 2003.

- **Hedged Congestion.** Although some months had congestion credit deficiencies, excess congestion charges collected in other months offset all but $23 million of the deficiencies, and FTRs were paid at 96 percent of the target allocation level in 2003, compared to 95 percent in 2002.

- **Monthly Congestion.** Differences in monthly congestion costs continued to be substantial. In 2003, these differences were driven by loop flows, 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.

- **Zonal Congestion.** LMP differentials were calculated for each PJM Mid-Atlantic Region zone to provide an approximate indication of the geographic dispersion of congestion costs. The data show some new overall congestion patterns in 2003.

- **Congested Facilities.** Both interface and transformer facilities experienced decreases in congested hours during 2003, while total congested hours on lines remained nearly unchanged from 2002 levels. There were increases in constrained hours on 230 kV lines.

- **Local Congestion.** Local congestion in the Delmarva Power & Light Company (DPL) zone continued to decrease in 2003 because of ongoing transmission reinforcement projects. Transmission reinforcements at Erie resulted in significantly less congestion in the Pennsylvania Electric Company (PENELEC) service territory and at the PJM western border. Congestion rose, however, in the Public Service Electric and Gas Company (PSEG) service territory on the Cedar Grove-Roseland 230 kV, Edison-Meadow Road 138 kV and Branchburg-Readington 230 kV lines.

- **Congestion Management Pilot.** A pilot program was conducted during the period July 11, through September 31, 2003, to measure the effectiveness of a proposed contingency management policy at reducing the incidence of off-cost operations. Analysis indicated 272 hours of avoided real-time, off-cost operations because of the new thermal emergency limits supplied under the pilot program.

Congestion associated with flows at the PJM/AEP and PJM/VAP interfaces and persistent congestion in defined areas within PJM suggest the importance of PJM's continuing efforts to improve the sophistication of its congestion analysis. Congestion analysis is central to implementing the United States Federal Energy Regulatory Commission (FERC) order to develop an approach identifying areas where investments in transmission would relieve congestion where that congestion might enhance generator market power and where such investments are needed to support competition.[14]

13 This is referred to as dispatching units out of merit order. 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.

14 96 FERC ¶61,061 (2001).

Financial Transmission and Auction Revenue Rights

In PJM, Financial Transmission Rights (FTRs) have been available to firm point-to-point and network transmission customers as a hedge against congestion charges. These firm transmission customers have had access to FTRs because they pay the costs of the transmission network that makes firm energy delivery possible. Individual firm transmission customers have received FTRs to the extent that they are consistent both with the physical capability of the transmission system and with the other firm transmission customers' requests for FTRs.

On June 1, 2003, PJM replaced the direct allocation of FTRs with an allocation of Auction Revenue Rights (ARRs) coupled with an Annual FTR Auction. The allocation of ARRs is identical to the previous process for allocating FTRs, but the value of the ARRs is based on a separate Annual FTR Auction. The ARR rules also provide that firm transmission customers are not required to take the market-based ARR value and may instead opt to take the underlying FTR via a process termed self-scheduling. ARRs provide holders with a revenue stream based on the locational price differences between ARR sinks and sources that result from the Annual FTR Auction.[15]

The Annual FTR Auction permits market participants to bid for the FTRs and thus provides a market-based determination of both ARR and FTR value. New FTR auction products were offered for the 2003/2004 planning period. These include annual and monthly FTR options, which are FTRs that, unlike traditional FTR obligations, can never be a financial liability. Additionally, 24-hour FTRs were added to the product portfolio consisting of on-peak and off-peak FTRs.

In addition to the Annual FTR Auction, PJM continues to run Monthly FTR Auctions designed to permit bilateral sales of FTRs and to permit participants to buy excess system FTRs.

Both ARRs and FTRs are financial instruments that entitle the holder to receive revenues (or pay charges) based on nodal price differences. The value of the ARRs is based on differences in nodal prices across selected paths that result from the Annual FTR Auction. The price of FTRs is determined by the auction results. The value of the FTR hedge is a function of the nodal prices in the hourly Day-Ahead Energy Market. ARR and FTR holders do not need to deliver energy to receive ARR or FTR credits, and neither instrument represents a right to the physical delivery of power. Both can, however, protect load-serving entities (LSEs) and other market participants from uncertain costs caused by transmission congestion in the PJM Day-Ahead Market. Market participants can also hedge against real-time congestion by matching real-time energy schedules with day-ahead energy schedules.

Overview

Market Structure

- **Supply and Demand.** During the 2003 ARR allocation process, 28,933 MW of ARRs were allocated, or 73 percent, out of 39,888 MW requested. Twenty percent, or 56,743 out of 279,898 MW, of buy bids for annual FTR obligations cleared. Of the cleared FTR buy bids, 25 percent were self-scheduled FTRs. Only 1 percent, or 24,175 out of 2,196,421 MW, of all buy bids for FTR options cleared. During the 2003 Monthly FTR Auctions, as in 2002, bid volume exceeded offer volume by nearly a 10:1 ratio, averaging approximately 55,000 versus 5,800 MW per month.

15 ARR values are functions of the implicit nodal price differences determined in the FTR auction since the final, optimal FTRs sold in the auction may not be identical to the ARRs.

Market Performance

- **Price.** In 2003, the $9,547 per MW-year paid for 24-hour annual FTR obligations was substantially higher than the $2,945 per MW-year paid for on-peak annual FTRs and the $1,357 per MW-year prices paid for off-peak FTRs. The overall average $3,235 per MW-year price paid for all annual FTR obligations was higher than the $1,989 per MW-year price paid for options. Prices in the 2003 Monthly FTR Auctions dropped from $369 per MW-month in 2002 to $195 MW-month in 2003, with most of the decrease occurring during the months after the June implementation of the Annual FTR Auction.

- **Volume.** Under the ARR allocation process, 28,933 MW of ARRs were allocated during the period. Introduction of the Annual FTR Auction in 2003 substantially increased the amount of long-term FTRs held by market participants. Some 32,907 MW of 24-hour, long-term FTRs were awarded, including 5,871 MW of FTRs into the Allegheny Power (APS) zone. Net of APS FTRs, these 27,036 MW of 24-hour FTRs slightly exceeded the 26,813 MW of PJM Mid-Atlantic Region FTRs held by market participants in 2002. However, an additional 28,026 MW of on-peak and 25,843 MW of off-peak FTRs were also awarded in 2003, more than doubling outstanding FTRs compared to 2002. Monthly FTR auction volume increased by 80 percent from 6,390 MW cleared in 2002 to 11,506 MW in 2003. Average monthly auction volume peaked in February 2003, with 23,188 MW of on-peak and off-peak FTRs exchanged.

- **Revenue.** During 2003, the Annual FTR Auction produced $332.8 million of net revenue, while the Monthly FTR Auction generated $22.0 million of net revenue. Average monthly auction revenue grew from $350,000 per month in 2000 to over $600,000 per month in 2001, $1.2 million per month in 2002 and $1.8 million per month in 2003.

- **Congestion Hedge.** Firm transmission customers that were allocated ARRs had $177 million of ARR credits and self-scheduled FTR target allocations and $199 million of congestion costs, a congestion hedging ratio of 89 percent. The ARR hedging shortfall was largely confined to two zones. If firm transmission customers had retained the allocated ARRs without self-scheduling FTRs, the ARRs would not have provided adequate revenue to hedge congestion fully. FTRs were paid $499 million of congestion credits against $521 million of FTR target allocations, a congestion hedging ratio of 96 percent.

A review of the operation of the 2003 FTR auction process indicates that the results were competitive and succeeded in increasing FTR access. Long-term FTR volume increased significantly via the new Annual FTR Auction, and there was a steady increase in MW of cleared FTRs in the ongoing Monthly FTR Auction. The introduction of rules explicitly providing for ARRs to track retail load shifting removes a potential barrier to competition.

Section 2 – Energy Market

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 Balancing 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. The PJM Market Monitoring Unit (MMU) analyzed measures of energy market structure and performance for 2003, including market size, concentration, residual supplier 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 Balancing Market results were competitive in 2003.

OVERVIEW

Market Structure

- **Market Size.** During the 12-month period from October 1, 2002, to September 30, 2003, approximately 5,000 MW of new generation plus 300 MW of upgrades to existing generation were added in PJM.[1] These increases were offset, in part, by the derating of 100 MW of generation and the retirement of 100 MW of existing facilities. The new generation was entirely gas-fired, with most of it based on combined-cycle technology. Upgrades to existing generation included approximately 150 MW in hydroelectric, 100 MW in gas-fired and 50 MW in nuclear facilities. During this same period, approximately 100 MW of gas-fired generation was derated and another 100 MW of gas-fired generation was retired. The net result of the addition of new combined-cycle units was a flattening of the middle portion of the PJM aggregate supply curve. As Table 2-1 shows, the PJM system peak load in 2003 was approximately 2,300 MW less than it had been in 2002.

- **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 suggest larger numbers of sellers splitting market sales more equally. Analysis of the PJM Energy Market indicates moderate market concentration overall, but high levels of concentration in the intermediate and peaking segments of the supply curve. Further, specific geographic areas of PJM exhibit moderate to high concentration that may be problematic when transmission constraints exist. No evidence exists, however, that market power was exercised in these areas during 2003, primarily because of generators' obligations to serve load. If those obligations were to change, significant market-power-related risk would exist.

- **Pivotal Suppliers.** A generation owner is pivotal if the output of the owner's generation facilities is required in order to meet market demand. When a generation owner is pivotal, it has the ability to affect market price. The residual supply index (RSI) is a measure of the extent to which generation owners are pivotal suppliers. When the RSI is less than 1.00, a generation owner is pivotal. The RSI results are consistent with the conclusion that the PJM Energy Market results were competitive in both 2002 and 2003, with an average RSI of 1.57 and 1.66, respectively. In 2003, a generation owner in the PJM Energy Market was pivotal for only six hours, less than 0.1 percent of all hours during the year. This represents a reduction in pivotal hours from 2002, when a generation owner was pivotal in the Energy Market for 87 hours, or approximately 1 percent of all hours.

- **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 severely underdeveloped. This underdevelopment is one of the basic reasons for maintaining an offer cap in PJM and other wholesale power markets. Total demand-side resources available in PJM during 2003 were 1,207 MW of active load management, 659 MW from the Emergency Load-Response Program and 724 MW from the Economic Load-Response Program. There were 445 MW enrolled in both the Load-Response Program and in active load management. The 4,918 MW in total DSR resources, including additional programs reported by PJM customers in response to a survey, were approximately 8.0 percent of peak demand.

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

Market Performance

- **Price-Cost Markup.** Price-cost markups are a measure of market power. The price-cost markup index is defined here as the difference between price and marginal cost, divided by price, which is load-weighted to account for congestion and normalized. Overall, data on the price-cost markup are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2003.

- **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 incentives to add 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. In 2003, the net revenue stream would not have covered the fixed costs of peaking units with operating costs between $70 and $75 per MWh which ran during all profitable hours.[2]

- **Energy Market Prices.** PJM's locational marginal prices (LMPs) reflect market structure and the conduct of individual participants. 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 2002 to 2003. The simple, hourly average system LMP was 35.2 percent higher in 2003 than in 2002, $38.27 per MWh versus $28.30 per MWh. When hourly load levels are reflected, the load-weighted LMP of $41.23 per MWh in 2003 was 30.5 percent higher than in 2002. However, when increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP was 9.5 percent lower in 2003 than in 2002, $28.60 per MWh compared to $31.60 per MWh.

  PJM average real-time energy market prices increased in 2003 over 2002 for several reasons, including significantly increased fuel costs and higher levels of demand during the first quarter of 2003. These changed fundamentals led to higher prices during normal system conditions. PJM did not experience extreme demand conditions during 2003. While LMPs were higher overall, LMP exceeded $150 per MWh for only 11 hours during all of 2003 and was greater than $200 per MWh for only one hour with a maximum of $210.83 per MWh.

The Energy Market results for 2003 reflected supply-demand fundamentals. While Energy Market results were competitive, analysis of the Energy Market has identified a number of concerns regarding market structure that could affect competitive market results when markets are tighter, including:

- The relatively high levels of concentration in the intermediate and peaking portions of the aggregate supply curve;
- The relatively high levels of concentration in markets defined by transmission constraints; and
- The relatively high levels of concentration in the ownership of marginal units.

Mitigation

- **Offer-Capping Statistics**. PJM rules limiting exercise of market power provide that PJM can offer-cap units when they would otherwise have the ability to exercise local market power. Offer-capping levels have declined since 2001. Offer-capping does not have a significant, negative impact on unit net revenues.

2 The $70 to $75 per MWh variable operating cost reflects 2003 average natural gas costs and the heat rate of a new peaking unit.

Market Structure

Market Size

During the June to September 2003 summer period, PJM Energy Markets received a maximum of 76,900 MW in offers, including generation and real-time net transactions. This was an increase of 4,800 MW over 2002. This 4,800 MW is comprised of a net addition of 5,000 MW of generation combined with an average reduction of 100 MW of real-time hydroelectric generation and an average decrease of 100 MW of real-time net transaction flow.[3] PJM did not establish a new record for peak demand in 2003. As Table 2-1 shows, PJM's all-time peak of 63,762 MW was set on August 14, 2002, for the hour ending 1600. The 2003 peak of 61,500 MW was set on August 22, 2003, for the hour ending 1600.

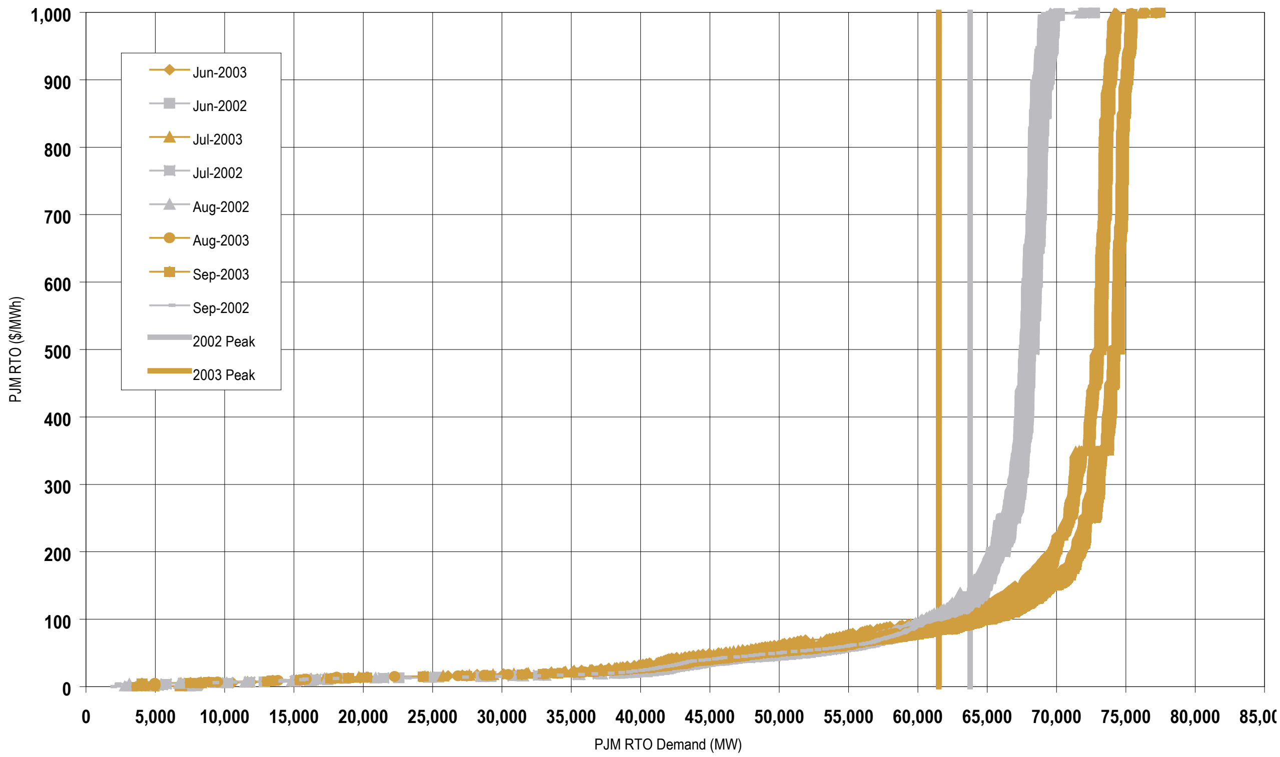
Table 2-1 Peak PJM Demand Days: 2001, 2002 and 2003

	22-Aug-03	14-Aug-02	9-Aug-01
Peak Demand (MW)	61,500	63,762	62,232
Maximum Daily LMP ($ per MWh)	$95.11	$445.30	$932.30
Average PJM LMP ($ per MWh)	$58.47	$88.00	$387.70
Average Peak PJM LMP ($ per MWh)	$65.89	$122.30	$559.40
Average Off Peak PJM LMP ($ per MWh)	$43.61	$19.20	$44.20

Price levels in 2003 were a function of market fundamentals, including lower peak demand levels and net additions to the aggregate Energy Market supply curve through new construction and upgrades to existing facilities. New generation additions and upgrades to existing units in PJM resulted in a net addition of approximately 5,000 MW of generation, after retirements and reductions in capacity. The shape of the aggregate supply curve was also changed by the new generation and its fuel mix. The result was that the midportion of the aggregate supply curve was extended (Figure 2-1). About 80 percent of the new generation was gas-fired combined-cycle, about 10 percent was gas-fired combustion turbine and the remaining 10 percent involved net upgrades to existing nuclear, hydroelectric and combustion turbines.

3 These increases in generation are calculated from October 1, 2002, through September 30, 2003, to reflect the summer to summer increase in generation.

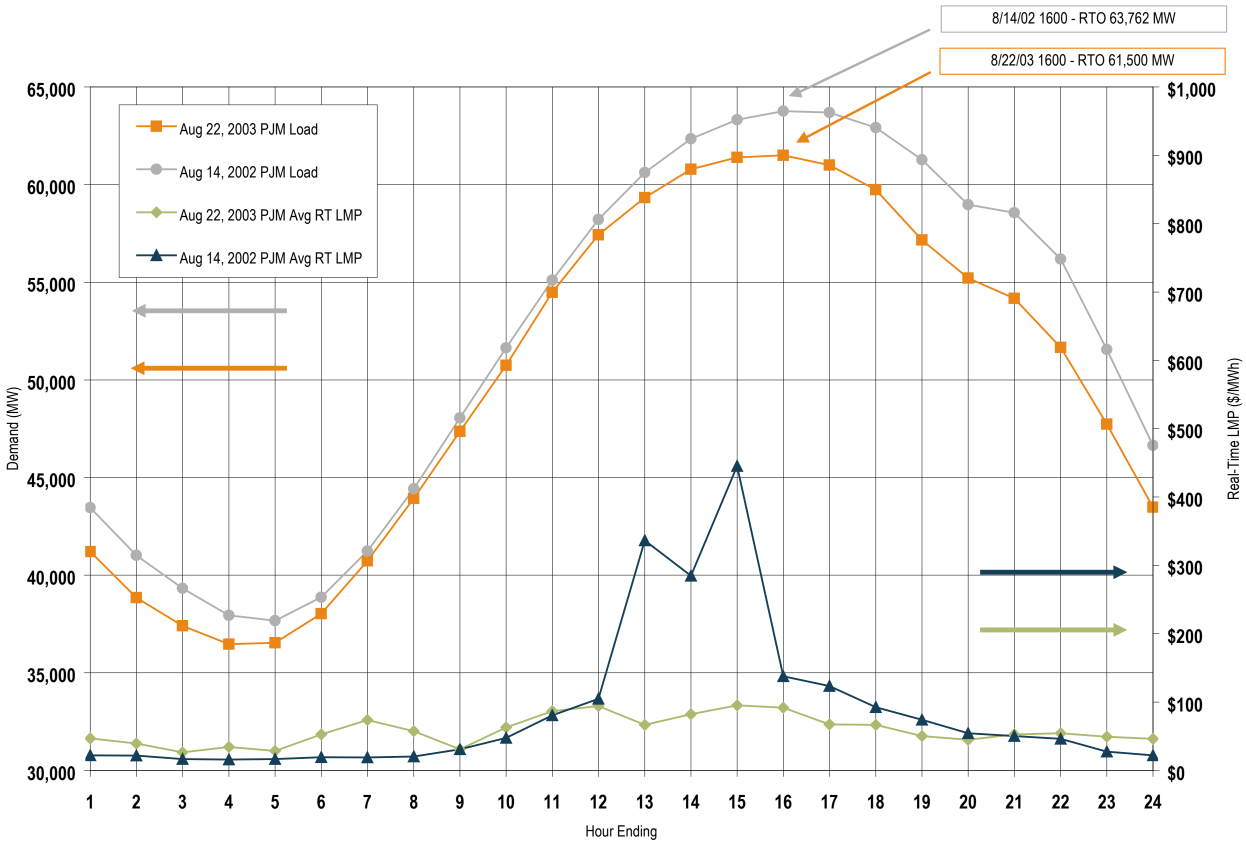
Figure 2-1 Average PJM Aggregate Supply Curves: June to September 2002 and 2003



During the summer of 2003, the demand curve intersected the supply curve at a lower price level than would have occurred with less additional generation or a different mix of additional generation (Figure 2-1).

Figure 2-2 compares the hourly load and prices for the peak-load days in 2003 and 2002. As expected, prices for the peak-load day in 2003 were lower than for the peak-load day in 2002. Average PJM LMP never exceeded $100 during the 2003 peak-load day, with $95 being the highest PJM average LMP; however, the $100 level was exceeded for six hours on the peak day in 2002, with $445 being the highest average LMP for the day.

Figure 2-2 PJM Peak Load Comparison: Friday, August 22, 2003, and Wednesday, August 14, 2002



Market Concentration

Concentration in the PJM Energy Market during 2003 was moderate overall, but high in the intermediate and peaking segments of the supply curve. High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. A pivotal supplier provides output that is required to meet load.[4] Further, specific areas of PJM exhibit moderate to high concentration ratios that may be problematic when transmission constraints exist. No evidence suggests that market power was exercised in these areas during 2003 primarily because of generation owners' obligations to serve load. If those obligations were to change, however, significant market power-related risk would exist.

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 and performance 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 share percentages of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators located in PJM, adjusted for hourly net imports (Table 2-2). The installed capacity HHIs were calculated based on the installed capacity of PJM generating resources, adjusted for aggregate import capability (Table 2-3).

4 See the RSI calculations below for a direct measure of whether generation owners were pivotal.

Actual net imports and import capability were incorporated in the hourly energy market and installed capacity 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.[5] The maximum installed HHI was calculated by assigning all import capability to the market participant with the largest market share; the minimum installed HHI was determined by assigning import capability to five nonaffiliated market participants and the overall average is the average of the two.

For both hourly and installed HHIs, generators were aggregated by ownership and, in the case of affiliated companies, by parent organization. Hourly and installed 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, while installed capacity HHIs by segment were calculated on an installed capacity basis, also unadjusted for import capability.

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 United States Federal Energy Regulatory Commission (FERC)[6] 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.

HHI Results

Calculations for installed and hourly HHI indicate that by the FERC standards the PJM Energy Market during 2003 was moderately concentrated (Table 2-2). Overall market concentration varied from 947 to 1593 based on the hourly Energy Market measure and from 908 to 1053 based on the installed capacity measure.

Table 2-2 PJM Hourly Energy Market HHI: 2003

	Minimum	Average	Maximum
Hourly	947	1213	1593

Table 2-3 PJM Installed Capacity HHI: 2003

	Minimum	Average	Maximum
Installed	908	981	1053

5 The method differs from that used in prior "State of the Market" reports. The hourly 2003 calculation reflects actual, company-specific net imports on an hourly basis while in prior years a range of net import ownership was imputed to develop a maximum and minimum HHI level.

6 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement," Order No. 592, pages 64-70.

Table 2-4 and Table 2-5 include HHI values for capacity and energy measures 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 installed measure indicates that, on average, all segments are moderately concentrated. For both hourly and installed measures, HHIs are calculated for facilities located in PJM; imports are not accounted for.

Table 2-4 PJM Hourly Energy Market HHI by Segment: 2003

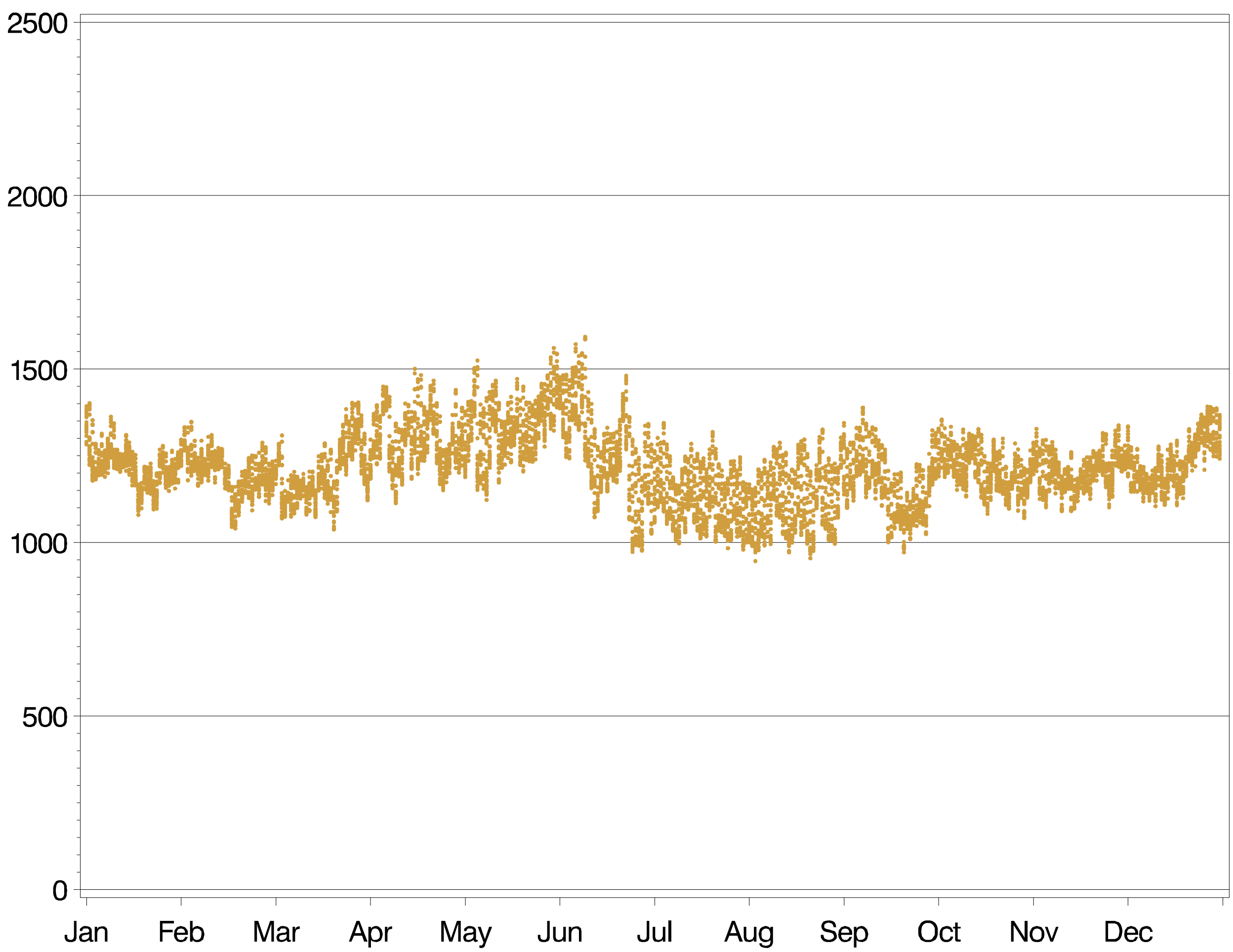
	Base	Intermediate	Peak
Maximum	1705	5772	9854
Average	1333	2055	4948
Minimum	1135	861	865

Table 2-5 PJM Installed Capacity HHI by Segment: 2003

	Base	Intermediate	Peak
HHI	1198	1037	1211

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

Figure 2-3 PJM Hourly Energy Market HHI: 2003



Local Market Concentration and Frequent Congestion

Eight PJM subareas showed high local market concentration and frequent congestion in 2002 or 2003: Northern PSEG (PSN), Northcentral PSEG (PSNC), eastern PJM, Delmarva Peninsula, Cedar subarea, Metropolitan Edison Company (Met-Ed) west, Erie and Towanda.

- **Northern PSEG (PSN)**: In 2003, congestion increased from 250 hours in 2002 to 1,059 hours, with 55 percent of all congestion occurring during on-peak periods. This increase was primarily caused by congestion on the Roseland-Cedar Grove 230 kV line, which contributed to 68 percent of all congestion in the area. An outage of the Linden-Goethals 230 kV line and generation dispatch patterns in the Public Service Electric and Gas Company (PSEG) zone were the main causes for this constraint. The Roseland-Cedar Grove constraint isolated approximately 4,500 MW of load and caused high market concentration, with an average HHI of 6500. Minimum and maximum HHIs were 4300 and 8900.

- **Northcentral PSEG (PSNC)**: In 2003, congestion increased from 459 hours in 2002 to 688 hours, with 75 percent of all congestion occurring during on-peak periods. Two constraints accounted for the majority of congestion in the area: the Edison-Meadow Road 138 kV line and the Branchburg-Readington 230 kV line. Congestion on Branchburg-Readington was attributable to area transmission outages, while congestion on Edison-Meadow Road was attributable to generation dispatch patterns in the Public Service Electric and Gas Company (PSEG) zone. These lines were congested 266 hours and 242 hours, respectively. These constraints isolated approximately 600 MW and 6,500 MW of load, respectively. Congestion caused average HHIs to range from 7000 to 7800. Minimum and maximum HHIs range from 4500 to 7000 and 8500 to 10000.

- **Eastern PJM**: During 2003, congestion on the Eastern Interface increased to 203 hours from 54 hours in 2002. Sixty-five percent of all congestion occurred during on-peak hours. The Eastern Interface isolated approximately 50 percent of total PJM system load. Eastern PJM had an average HHI of 1935, with a minimum HHI of 1300 and a maximum HHI of 2500.

- **Delmarva Peninsula**. Continued transmission improvements have reduced the occurrence of individual constraints in this area. Overall, congestion fell from 792 hours in 2002 to 522 hours in 2003. Seventy-five percent of all congestion occurred during on-peak periods. Notably, not one constraint occurred for more than 100 hours in 2003. In comparison, four constraints occurred for 100 hours or more in 2002. The Hallwood-Oak Hall 138 kV line was constrained 286 hours in 2002, but only six hours in 2003. Similarly, the Cheswold 138/69 kV transformer, the Indian River 230/138 kV transformer and the Church 230/69 kV transformer were all down from 263, 113 and 130 hours in 2002, to 77, 81 and 0 hours in 2003. Across these constraints, isolated load varied from 70 MW for the Hallwood-Oak Hall 138 kV line and Cheswold 138/69 kV transformer, to approximately 1,000 MW for the Indian River 230/138 kV transformer. Market concentration remained high during these constraints, with average HHIs ranging from 4675 to 5475. Minimum and maximum HHIs ranged from 900 to 1200 and from 8200 to 10000, respectively.

- **Cedar Subarea**. In 2003, the Cedar subarea in the Atlantic City Electric Company (AECO) zone continued to be frequently constrained. Two constraints accounted for most of the congestion in the area, which was slightly down from 786 hours in 2002, to 638 hours in 2003. Sixty-seven percent of all congestion was during on-peak periods. The Cedar interface and the Cedar-Motts 69 kV line were constrained for 396 hours and 245 hours, respectively. The Cedar-Motts 69 kV line occurred less frequently in 2003, down from 537 hours in 2002, but the Cedar interface increased from 166 hours in 2002. These two constraints isolated approximately 100 MW of load and caused the average HHI to be 6000. The minimum and maximum HHIs were 2000 and 10000.

- **Met-Ed West**. In 2003, the Met-Ed west subarea was constrained 253 hours, down from 570 hours in 2002. Ninety-six percent of all congestion in the area occurred during on-peak periods. Primarily two constraints contributed to congestion in the area: the Jackson 230/115 kV transformer, constrained 45 hours in 2003, down from 235 hours in 2002 and the Yorkana 230/115 kV transformer, constrained 149 hours, down from 186 hours in 2002. Congestion on these transformers can be attributed to the Hunterstown 500/230 kV transformer outage, which occurred in August of 2002 and continued until August of 2003.[7] These two constraints isolated approximately 1,000 MW of load and caused high market concentration, with an average HHI of 4461. Minimum and maximum HHIs were 1075 and 7850, respectively.

- **The Erie Subarea**. In 2003, the Erie subarea, located in the northwest area of the Pennsylvania Electric Company (PENELEC) zone, was constrained 324 hours, of which 42 percent occurred during on-peak periods. This was approximately a 70 percent decrease from 2002 when congestion occurred for 1,054 hours. In March 2003, congestion in the area was greatly reduced by the addition of a second Erie West 345/115 kV transformer which eliminated the occurrence of the Erie West 345/115 kV transformer constraint. Prior to the new addition, congestion from this constraint occurred for 182 hours in the first quarter of 2003 and then for no hours during the rest of the year. This was a significant decrease from a total of 900 hours in 2002. The Erie West constraint isolated approximately 800 MW of load and caused the average HHI to be 5400. The minimum and maximum HHIs were 1100 and 9800, respectively.

- **The Towanda Subarea**. In 2003, the Towanda subarea, located in the northeast area of the PENELEC zone, was constrained 490 hours, of which 29 percent occurred during on-peak periods. This was a decrease from 844 hours in 2002. However, in 2003, congestion on the North Meshoppen 230/115 kV transformer doubled from 221 hours in 2002, to 442 hours. As a result, during 2003, a second transformer and series reactors were installed at North Meshoppen to alleviate this congestion. In 2002, the Towanda interface had significant congestion attributable to area transmission outages and to its use to control congestion on the North Meshoppen transformer. These two constraints isolated approximately 500 MW of load and caused the average HHI to be 5400. Minimum and maximum HHIs were 1000 and 10000, respectively.

Pivotal Suppliers

In addition to the aggregate PJM and local market HHI calculations used to measure market concentration, the residual supply index (RSI) is a measure of the extent to which generation owners are pivotal suppliers in the PJM Energy Market. A generation owner is pivotal if the output of the owner's generation facilities is needed to meet demand. When a generation owner is pivotal, it has the ability to affect market price. For a given level of market demand, the RSI compares the market supply net of an individual generation owner's supply 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.[8] $Supply_i$ is the supply owned by the individual generation owner "i" and $Demand_m$ is total market demand. If the RSI is greater than 1.00, the supply of the specific generation owner is not needed to meet market demand and that generation owner has a reduced ability to influence market price. If the RSI is less than 1.00, the supply owned by the specific generation owner is needed to meet market demand and the generation owner is a pivotal supplier with a greater ability to influence prices.

RSI was calculated hourly for every 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 (Table 2-6). The RSI was also calculated for the largest two generation owners together and the largest three generation owners together in order to determine the extent to which two or three suppliers were jointly pivotal. These results are reported in Table 2-7 and Table 2-8.

7 See Section 6, "Congestion," for a more in-depth discussion of Met-Ed congestion and this particular outage.

8 Total supply in the Energy Market is the sum of all offers to provide energy.

RSI Results

The RSI results reported in Table 2-6 are consistent with the conclusion that PJM Energy Market results were competitive in both 2002 and 2003, with an average hourly RSI of 1.57 and 1.66, respectively.[9] In 2003, a generation owner in the PJM Energy Market was pivotal for only six hours, less than 0.1 percent of all hours during the year. This represents a reduction in pivotal hours from 2002, when a generation owner was pivotal in the Energy Market for 87 hours, or approximately 1 percent of all hours. During the hours when a single generation owner was pivotal in the Energy Market in 2002 and 2003, demand averaged 60,000 MW. This indicates that, as the PJM Energy Market reaches a demand close to its peak of approximately 63,000 MW, one or more large market suppliers is likely to be pivotal and to have the ability to influence prices. The reduction in hours when a generation owner was pivotal between 2002 and 2003 resulted primarily from a reduction in high load hours. PJM load exceeded 60,000 MW for only 12 hours during 2003, but exceeded 60,000 MW for 83 hours in 2002.

Table 2-6 PJM RSI Statistics: 2002-2003

Year	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours in Year RSI < 1.00	Average RSI	Minimum RSI
2003	91	6	0.07%	1.66	0.99
2002	339	87	0.99%	1.57	0.91

Table 2-7 shows RSI results for the top two generation owners together.

Table 2-7 PJM Top-Two Supplier RSI Statistics: 2002-2003

Year	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours in Year RSI < 1.00	Average RSI	Minimum RSI
2003	822	299	3.41%	1.40	0.83
2002	1,784	748	8.54%	1.29	0.71

Table 2-8 shows RSI results for the top-three generation owners together.

Table 2-8 PJM Top-Three Supplier RSI Statistics: 2002-2003

Year	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours in Year RSI < 1.00	Average RSI	Minimum RSI
2003	2,881	1,448	16.53%	1.20	0.70
2002	4,904	3,000	34.25%	1.09	0.52

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

Figure 2-4 shows the comparison of the RSI duration curves in 2002 and 2003. The curve shows the improvement in 2003 with a decreased number of hours having an RSI index below 1.0.

Figure 2-4 PJM RSI Index Duration Curve: 2002-2003

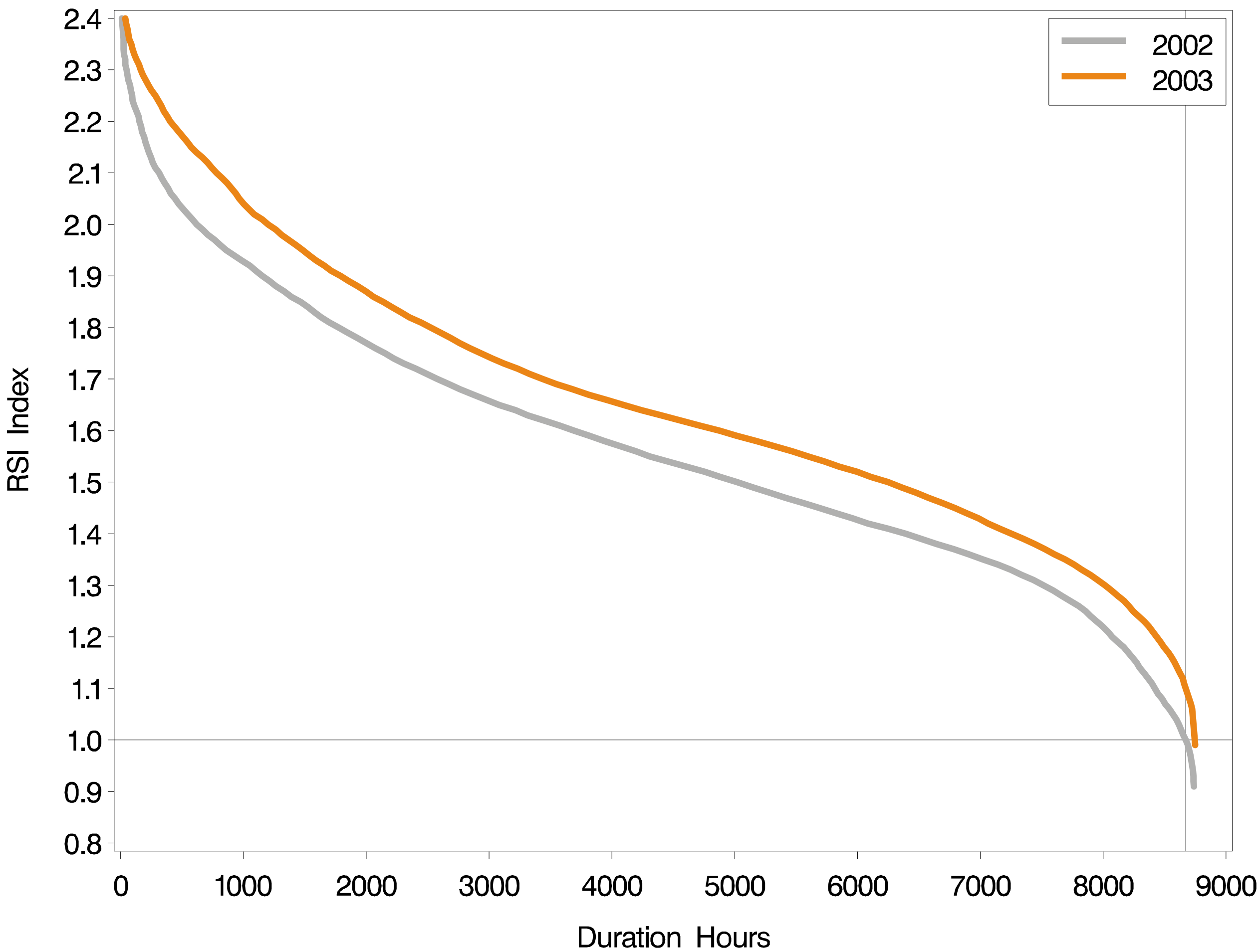
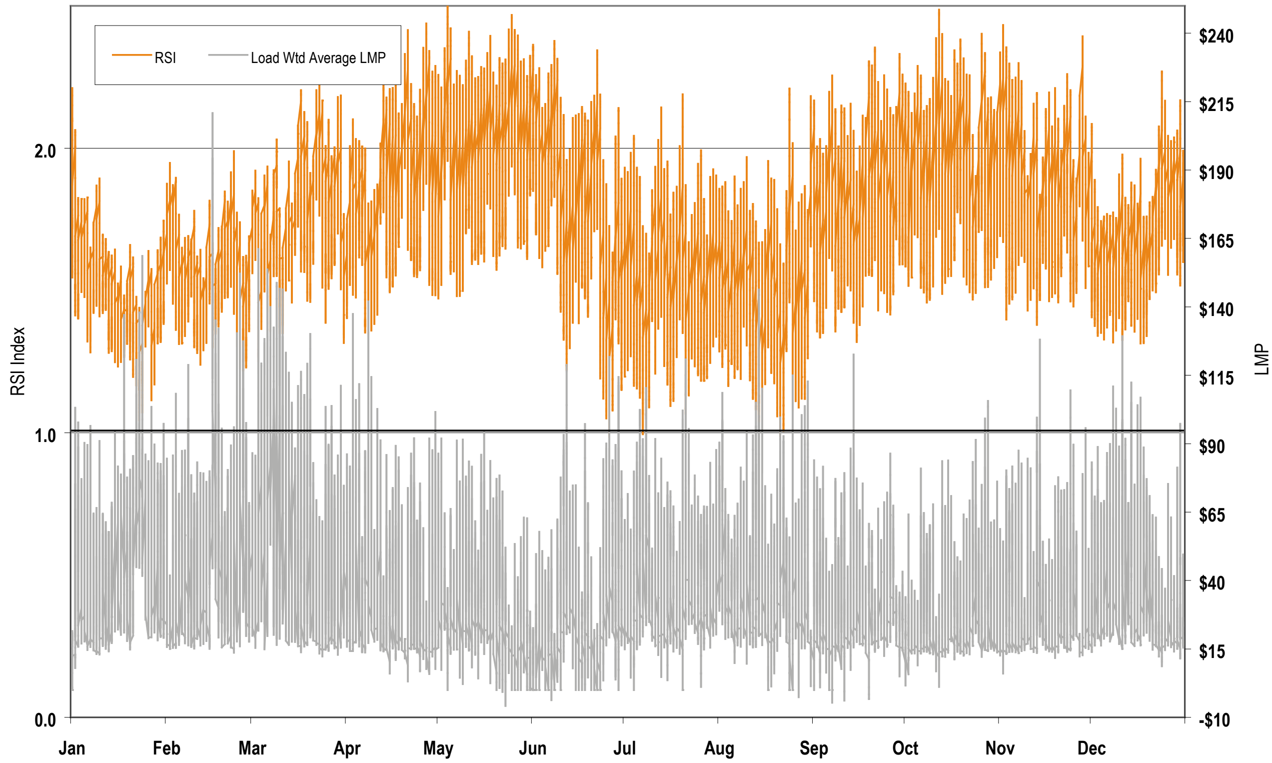


Figure 2-5 shows that there was no strong correlation between RSI and LMP.

Figure 2-5 PJM Hourly RSI and Average LMP: 2003



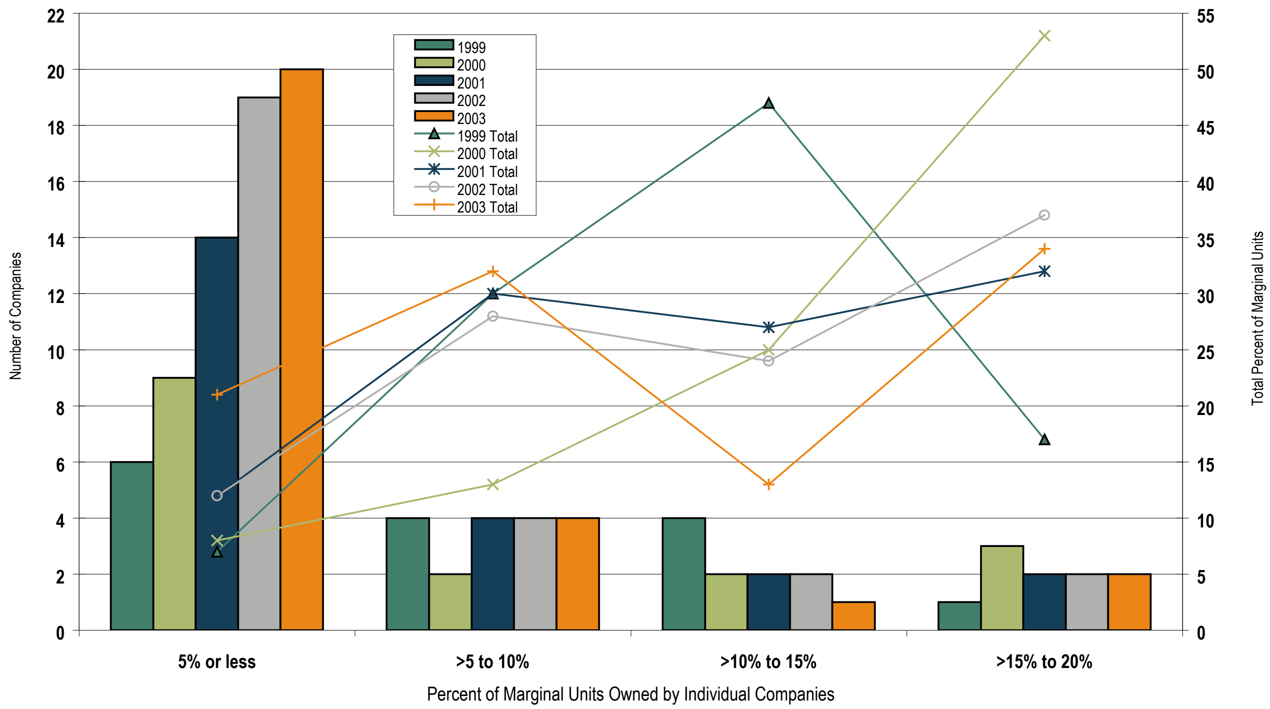
Ownership of Marginal Units

Figure 2-6 shows ownership distribution for marginal units.[10] The bars show all units that were on the margin for one or more five-minute intervals during the specified year. In 2003, two companies each owned 15 to 20 percent of the marginal units, while one other company owned 10 to 15 percent of the marginal units. The figure's "2003 Total" line shows that the two companies that each separately owned from 15 to 20 percent of the marginal units, together owned the marginal unit in just under 35 percent of the five-minute intervals. This is close to the 2002 result. In 2002, four companies individually owned the marginal unit in more than 10 percent of the intervals and together owned the marginal unit in about 60 percent of the intervals. By comparison, in 2003 the four companies with the highest share of marginal units together owned the marginal unit in about 55 percent of the intervals. The top seven companies owned the marginal unit in about 80 percent of the intervals. In 2002, the top eight companies owned about 90 percent of the marginal units; in 2001, the top four companies owned about 60 percent of the marginal units; in 2000, the top five companies owned about 80 percent of the marginal units; in 1999, the top five companies owned more than 60 percent of the marginal units.

Together with data on HHIs by supply curve segment, distribution of ownership of marginal units causes further concern about the structure of the Energy Market.

10 The calculation method was refined for 2003 to better account for marginal units owned by more than one company.

Figure 2-6 Ownership of Marginal Units



Offer-Capping

PJM has clear rules for limiting exercise of local market power. These rules are set out in the PJM Operating Agreement, Schedule 1, Section 6.4.2. The local market power rules provide that PJM shall cap the offers of units when conditions on the transmission system and the absence of sufficient competition in the area defined by the transmission constraint put units in a position to exercise local market power. 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 basic facts of offer-capping for local market power are that:

- Units are offer-capped only if they must be dispatched out of economic order;
- The offer cap is generally the marginal cost of the unit plus 10 percent; and
- Offer-capped units receive the higher of their offer cap or the market price

Figure 2-7 through Figure 2-14 present data on the frequency of offer-capping, by month, for the past three years.

Offer-capping has declined since 2001, the first year for which data are presented. Conditions in specific subareas of PJM have affected the overall frequency of offer-capping. In 2001, constraints associated with construction of transmission system upgrades on the Delmarva Peninsula resulted in more frequent offer-capping. As the transmission projects were completed, congestion decreased significantly because of both the transmission improvements and the ending of maintenance outages. The combined effect of these factors was the decrease in offer-capped hours per MW in 2002. In 2001, there were 37,251 unit-hours of offer-capped operation, compared with 25,421 in 2002 and 18,809 in 2003.

Figure 2-7 **Average Real-Time Offer-Capped Units (by Month)**

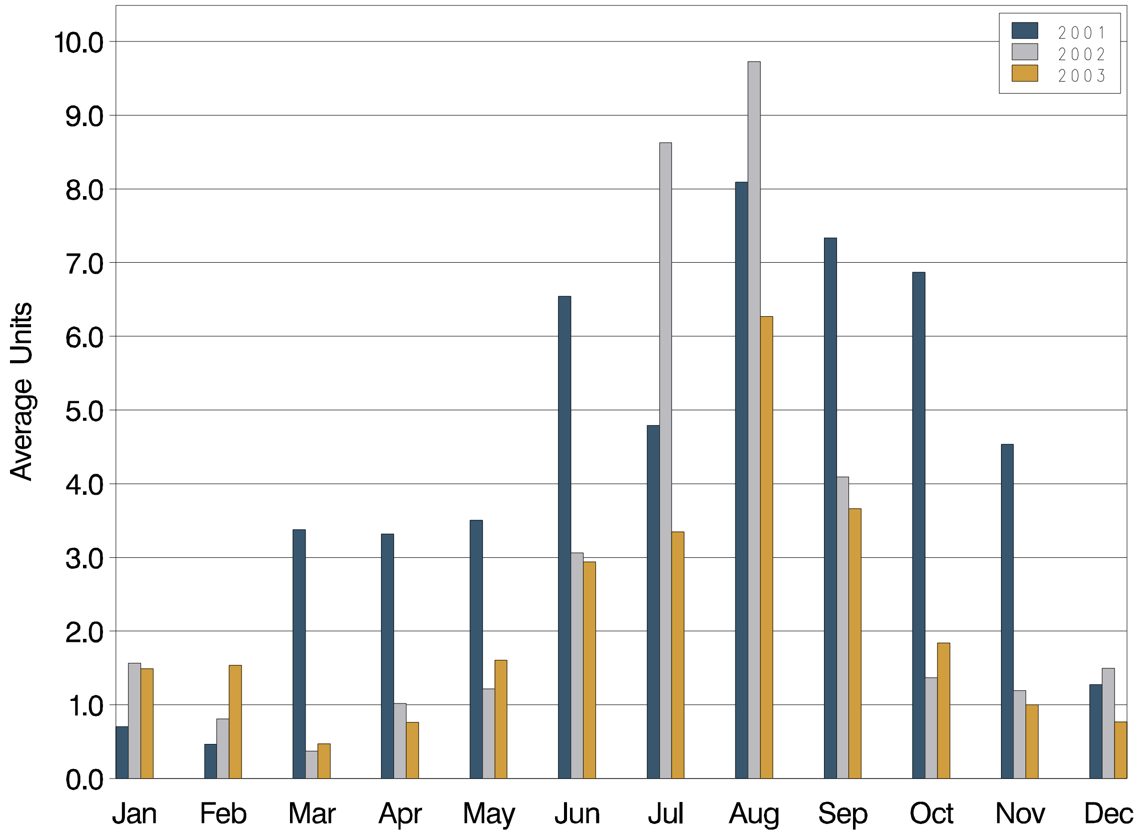


Figure 2-8 **Percent of Real-Time Offer-Capped Unit Hours versus Bidding Units (by Month)**

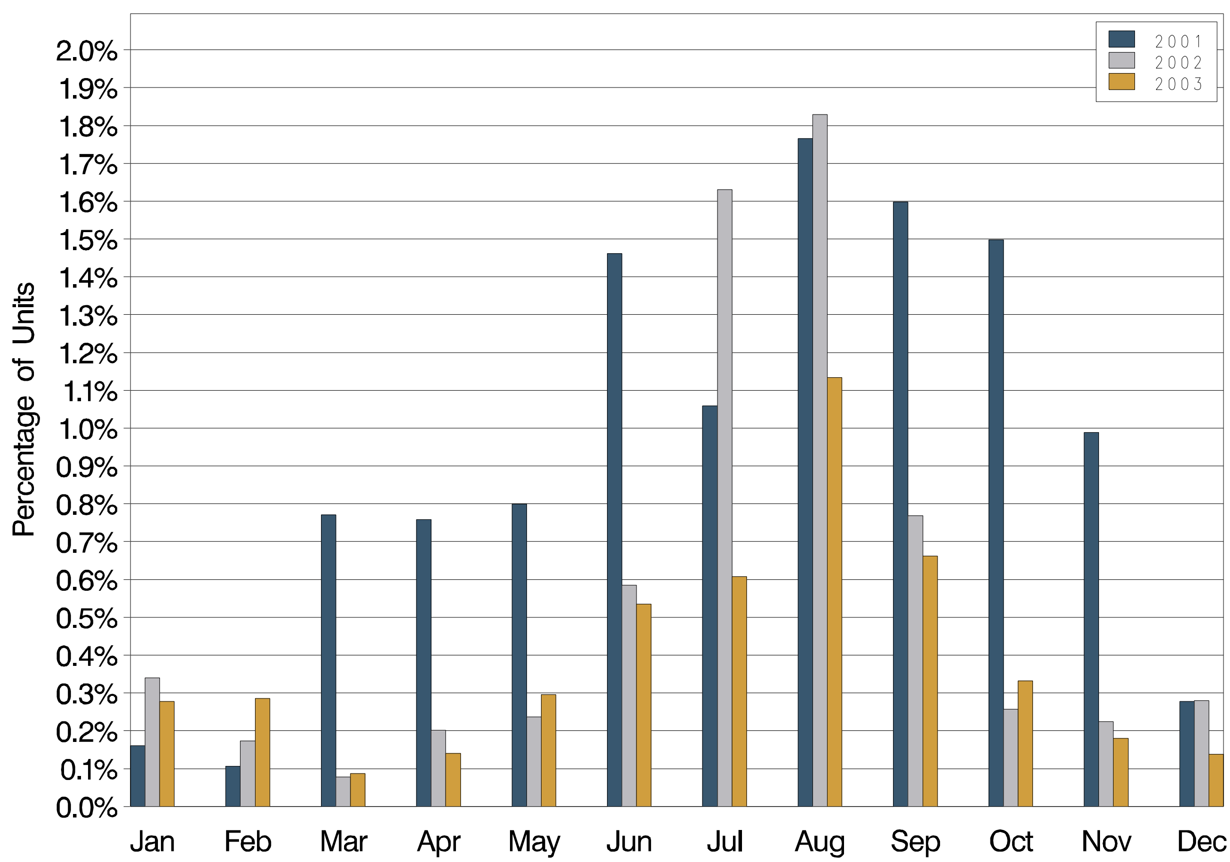


Figure 2-9 Average Real-Time Offer-Capped MW (by Month)

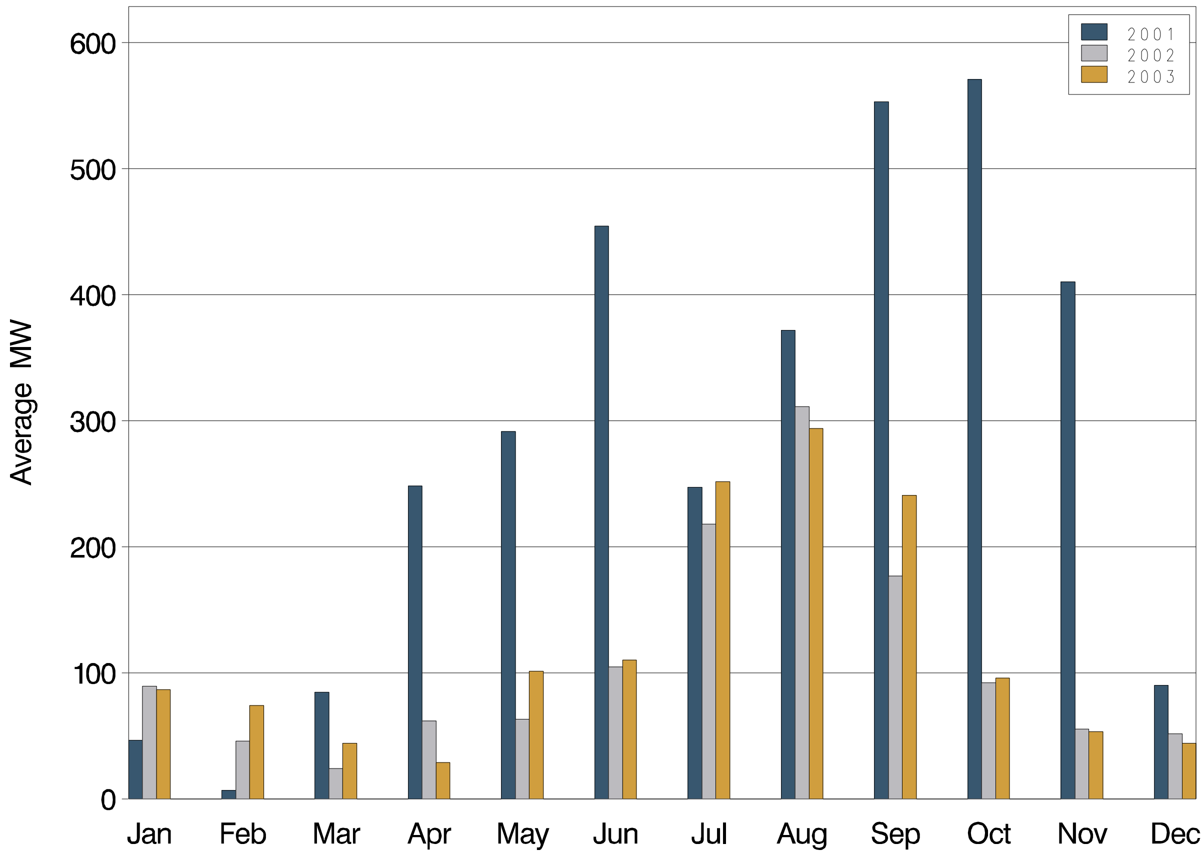


Figure 2-10 Percent of Real-Time Offer-Capped MW (by Month)

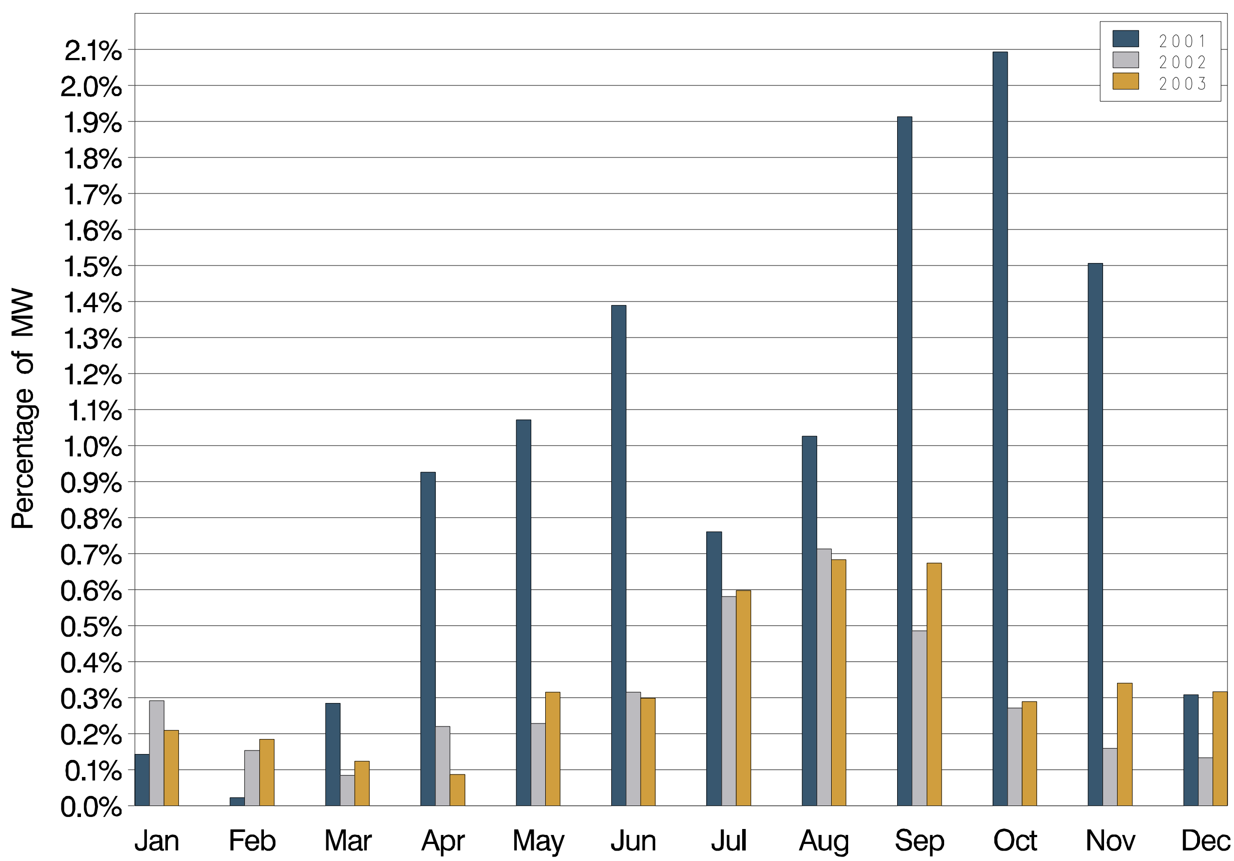


Figure 2-11 Average Day-Ahead Offer-Capped Units (by Month)

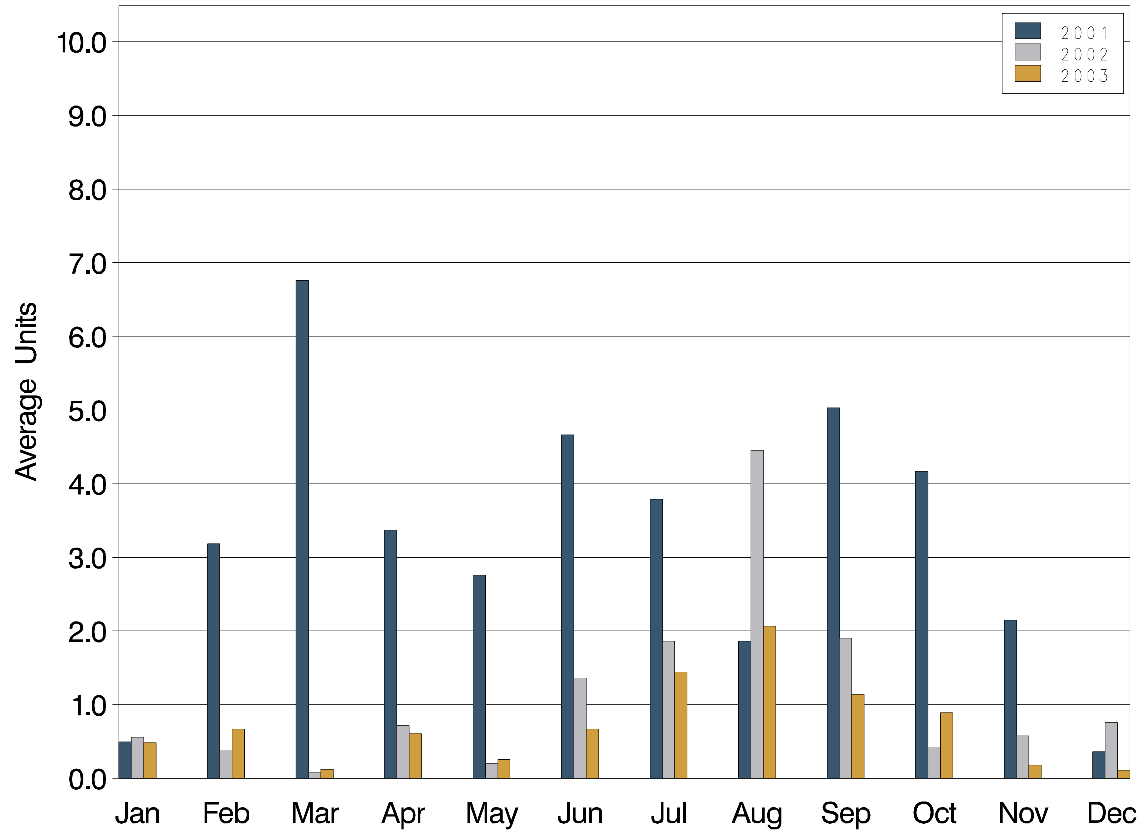


Figure 2-12 Percent of Day-Ahead Offer-Capped Unit Hours versus Bidding Units (by Month)

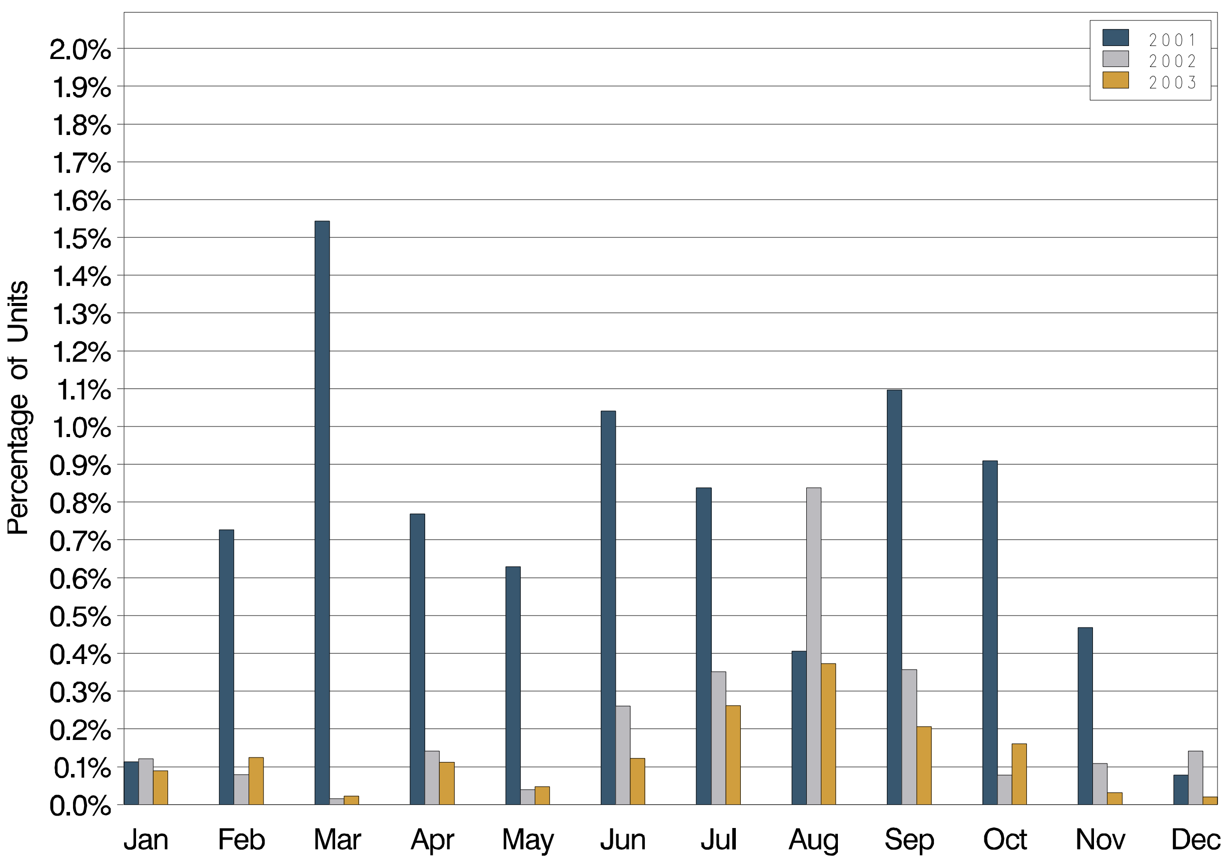


Figure 2-13 Average Day-Ahead Offer-Capped MW (by Month)

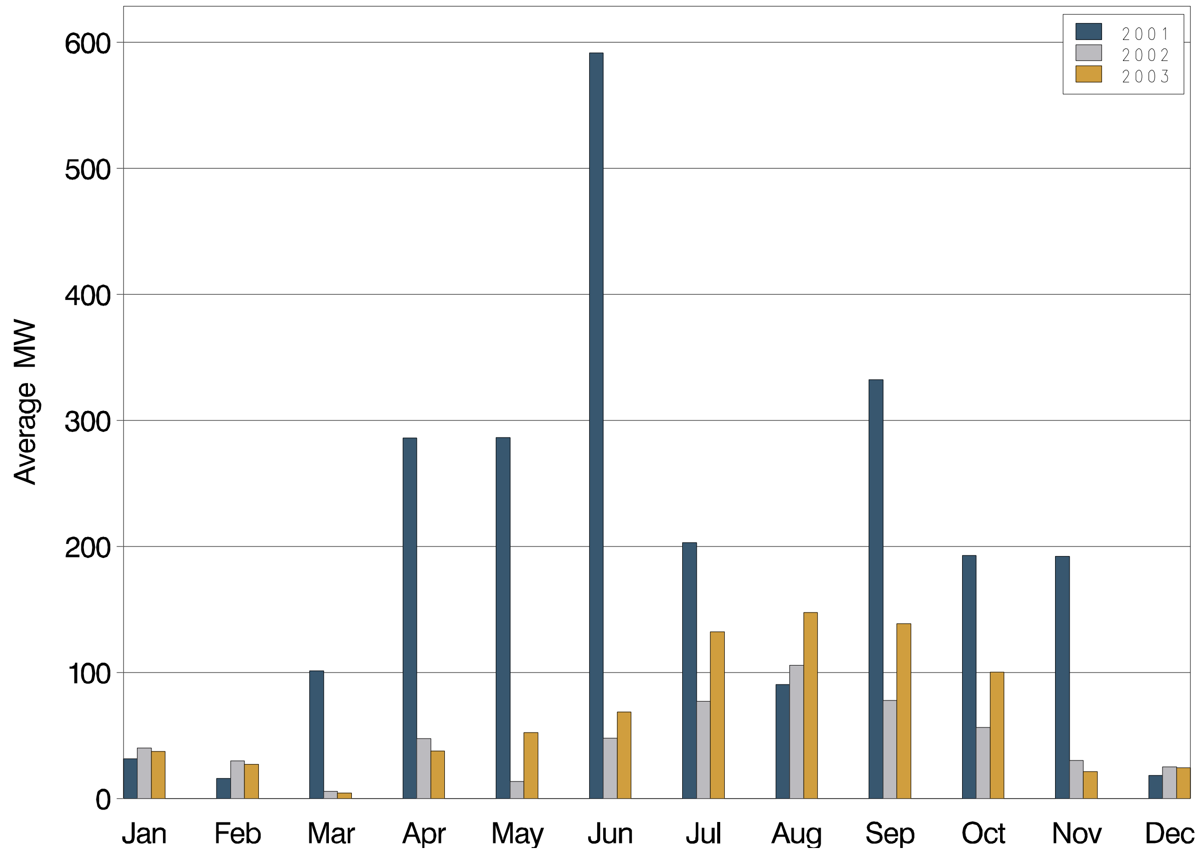
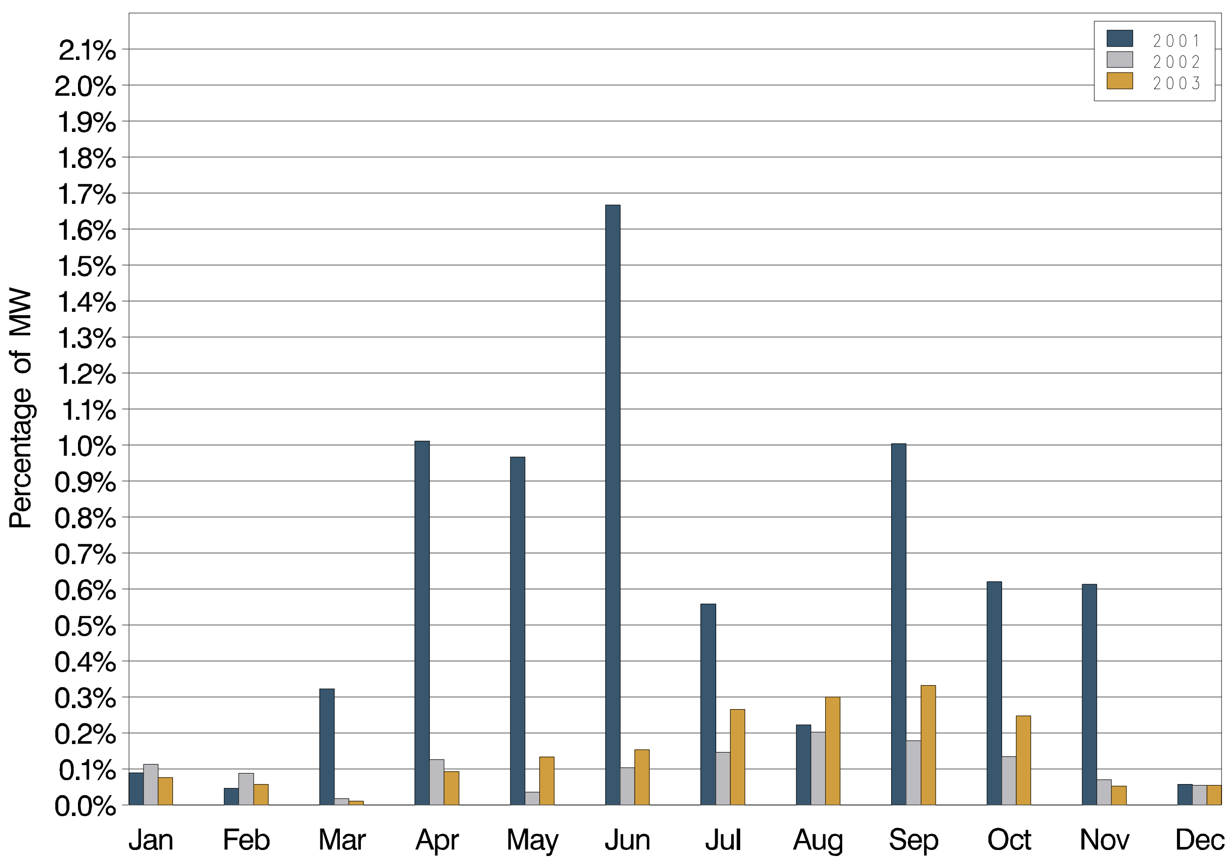


Figure 2-14 Percent of Day-Ahead Offer-Capped MW (by Month)



The following tables show the number of generation units that met the criteria of both offer-capped run hours and percentage of run hours that were offer-capped for the year indicated. For example, in 2001 three units were both offer-capped for more than 80 percent of their run hours and had at least 300 offer-capped run hours.

Table 2-9 2001 Offer-Capped Statistics

Percentage of Offer-Capped Run Hours	2001 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	0	0	2	2	3	3
80%	0	0	3	3	6	9
75%	0	1	4	4	9	14
50%	1	2	5	6	12	31
25%	13	16	19	20	28	72
10%	18	21	24	27	39	117

Table 2-10 2002 Offer-Capped Statistics

Percentage of Offer-Capped Run Hours	2002 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	2	2	3	6	6	6
80%	4	4	8	15	19	19
75%	4	4	8	16	25	25
50%	4	5	17	26	38	53
25%	6	7	19	28	52	124
10%	6	8	20	29	61	170

Table 2-11 2003 Offer-Capped Statistics

Percentage of Offer-Capped Run Hours	2003 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	0	0	0	0	1	2
80%	0	1	1	2	3	11
75%	1	2	2	5	9	18
50%	1	2	2	11	23	51
25%	5	9	11	20	35	97
10%	6	10	12	23	49	153

As a general matter, offer-capping did not result in financial harm to the affected units. Frequently offer-capped units received net revenues that were close to those received by units not offer-capped or that were offer-capped, but for significantly fewer hours. The extent offer-capped units had relatively low net revenues in 2003 was the result of overall market conditions and not offer-capping. In fact, offer-capping can, at times, result in higher revenues for offer-capped units than other comparable units because the offer-capped units operate when market conditions result in comparable units not operating.

Market Performance

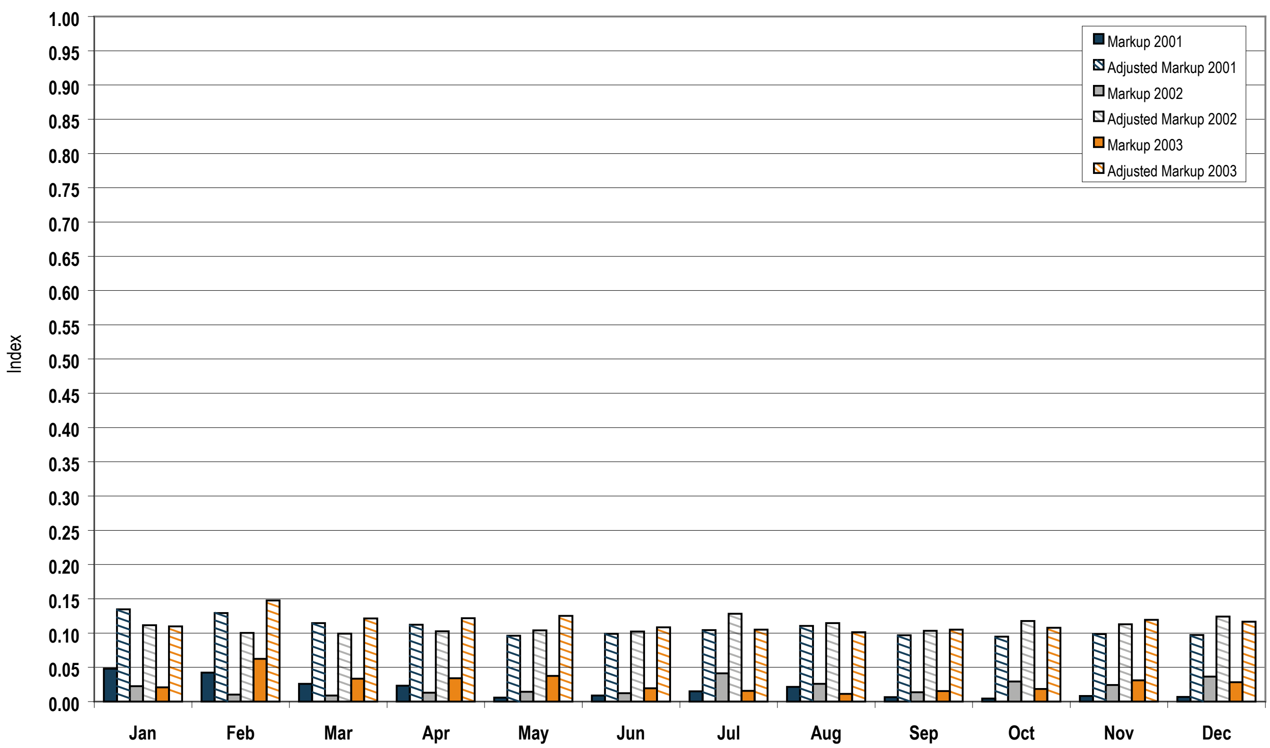
Price-Cost Markup Index

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 is determined by the offer of the marginal unit and marginal cost is from the highest marginal cost unit operating (The markup index = $(P - MC)/P$. It is load-weighted to account for congestion and then normalized.) This markup index measure can vary from -1.00, when price is less than marginal cost to 1.00 when price is higher than marginal cost[11] (Figure 2-15).

PJM has data on price and cost offers for every unit in PJM if its construction began before July 9, 1996. The markup index can thus be calculated directly for any time period. The markup index is calculated for the marginal unit or units in every five-minute period. The marginal unit is the unit that sets LMP in the five-minute interval. There are multiple marginal units when congestion exists. Congestion is accounted for by weighting the markup index for each of the multiple marginal units, in a five-minute interval with congestion, by the load that pays the price determined by that marginal unit.[12] The resulting markups are adjusted so that the markup index compares the price offer for the marginal unit to the cost corresponding to the output of the highest marginal cost unit operating, rather than to the marginal cost of the marginal unit.

Figure 2-15 Average Monthly Load-Weighted Markup Indices



11 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.

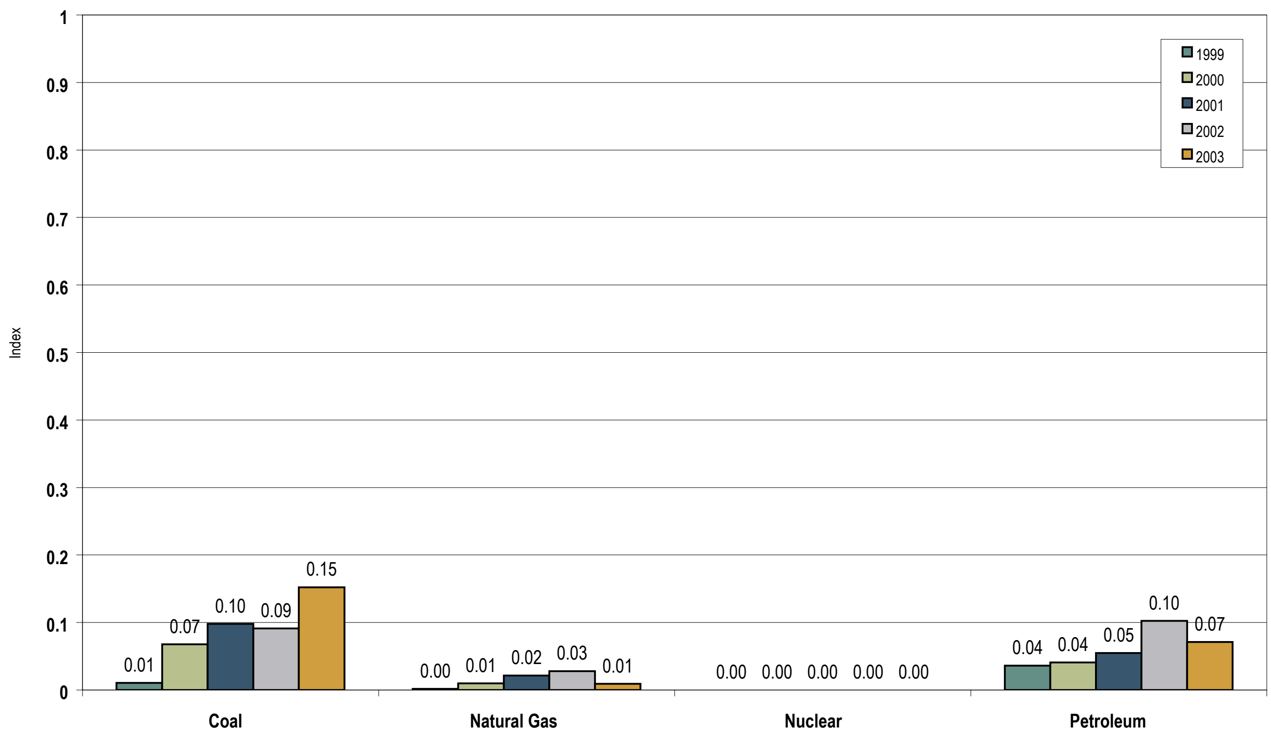
12 For example, if a marginal unit with a markup index of 0.50 set the LMP for 3,000 MW of load in an interval and a second marginal unit with a markup index of 0.01 set the LMP for 27,000 MW of load, the weighted-average markup index for the interval would be 0.06.

Figure 2-15 shows the average monthly markup index. The average markup index was 0.03 in 2003, with a maximum markup index of 0.06 in February and a minimum markup index of 0.01 in August. Generators in PJM are permitted to provide cost-based offers that include a 10 percent markup over marginal cost. Since a significant number of generators have increased their cost bids by this 10 percent, the calculated markup index is likely to be low. The adjusted markup index in Figure 2-15 assumes that all unit owners include a 10 percent markup over cost. Given this assumption, the average 2003 markup index was 0.12, with a maximum index of 0.15 in February and a minimum index of 0.10 in several other months.[13]

The markup index calculation is based on the marginal production cost of the highest marginal cost operating 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, as a cost component. Thus, if the marginal unit is a combustion turbine (CT) with a price offer equal to $500 per MWh and the highest marginal cost of an operating 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 fuel type, plant type and ownership. Figure 2-16 shows the average, unit-specific markup by fuel type. The unit markup index [(*P-MC*)/*P*] is calculated using price and marginal cost for the specific unit of the identified fuel type that is marginal during any five-minute interval and normalized. During 2003, units using coal and petroleum showed the highest unit markup indices averaging 0.15 and 0.07, respectively.[14]

Figure 2-16 Average Markup Index by Type of Fuel



13 The 10 percent markup is permitted, in part, to account for inaccuracies in marginal cost calculations. Thus, the correct markup index lies between the adjusted and unadjusted index values.

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

Figure 2-17 shows the “Type of Fuel Used by Marginal Units.” Between 2002 and 2003, the share of coal decreased from 55 to 53 percent; the share of natural gas increased from 23 to 28 percent; the share of nuclear units remained steady and the share of petroleum decreased from 21 to 17 percent.

Figure 2-17 Type of Fuel Used by Marginal Units

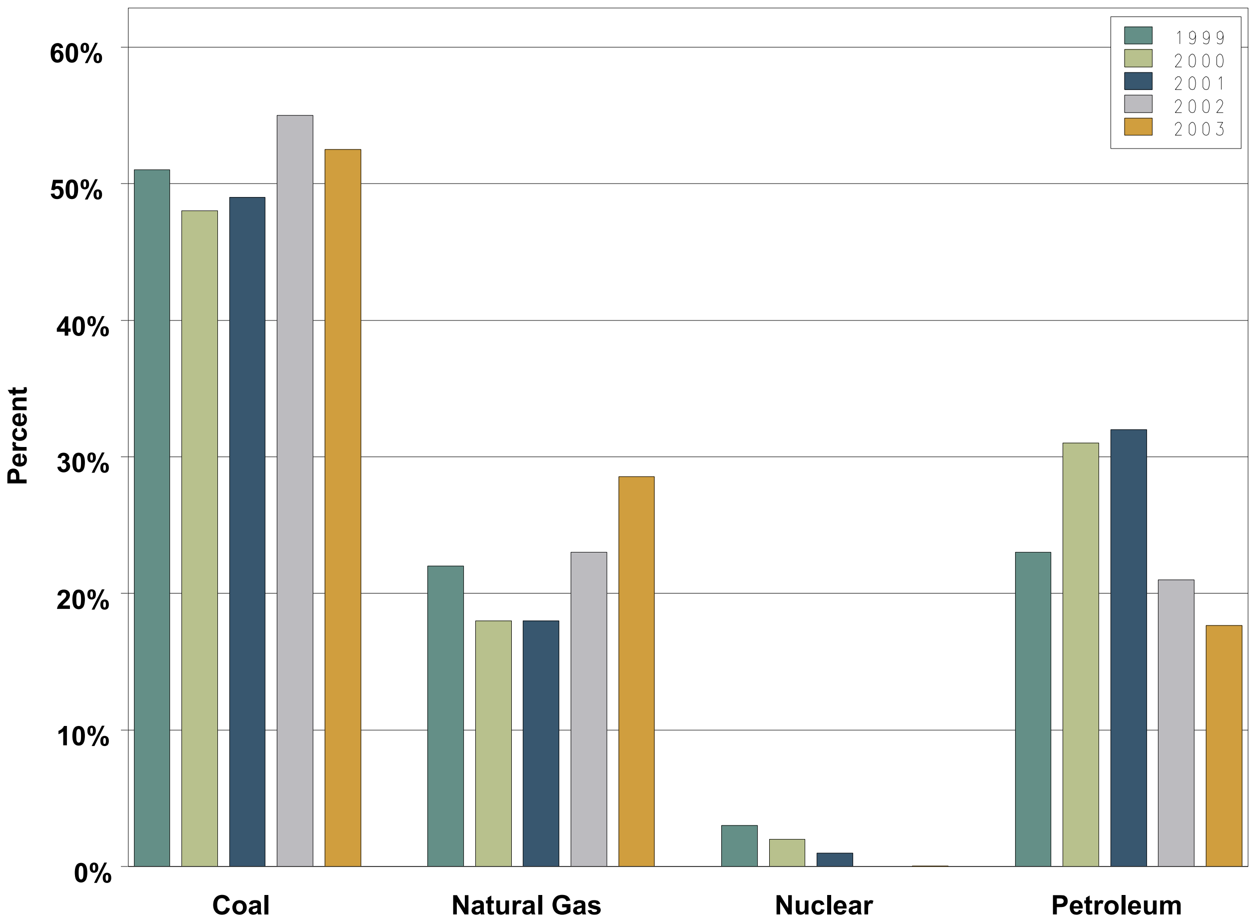


Figure 2-18 shows the type of units on the margin from 1999 to 2003. During 2003, the marginal unit was a CT 22 percent of the time and a steam unit 77 percent of the time.

Figure 2-18 Type of Marginal Unit

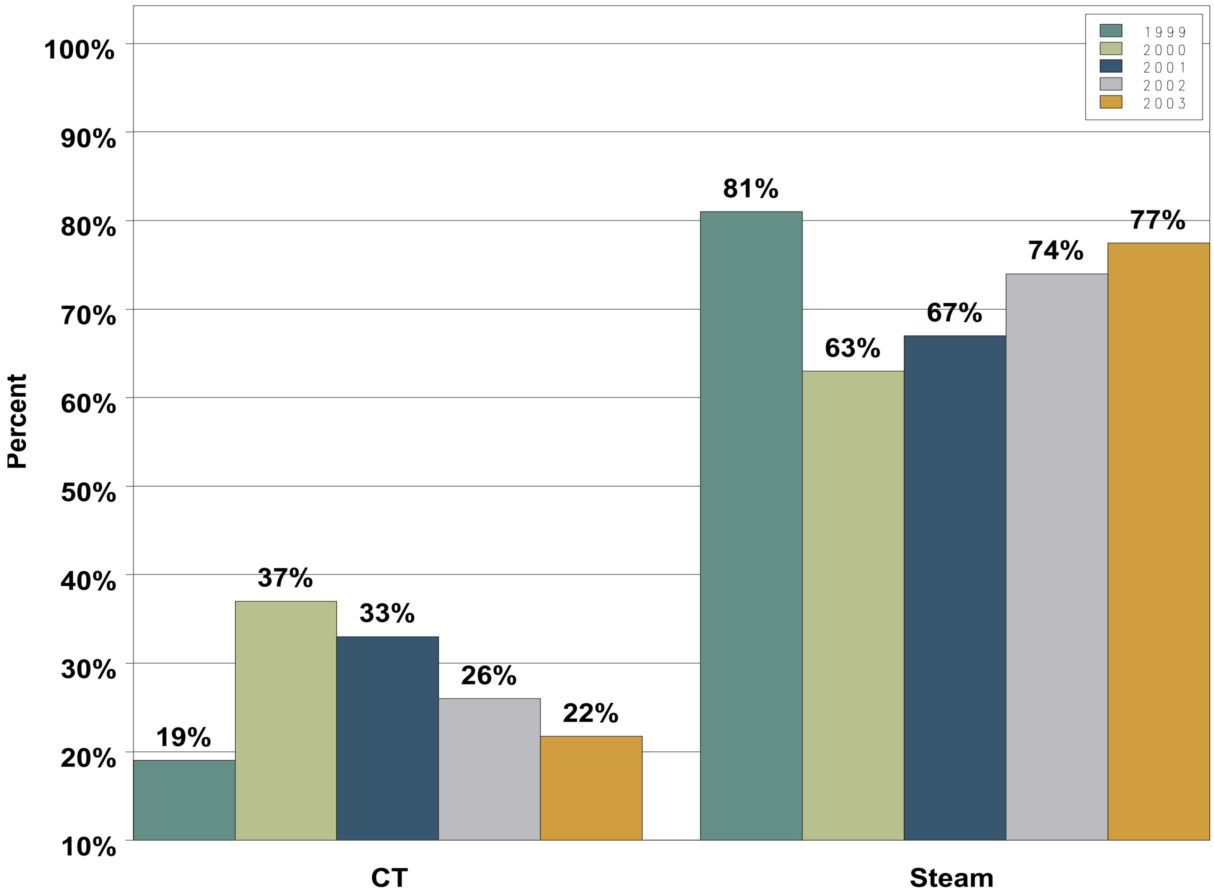
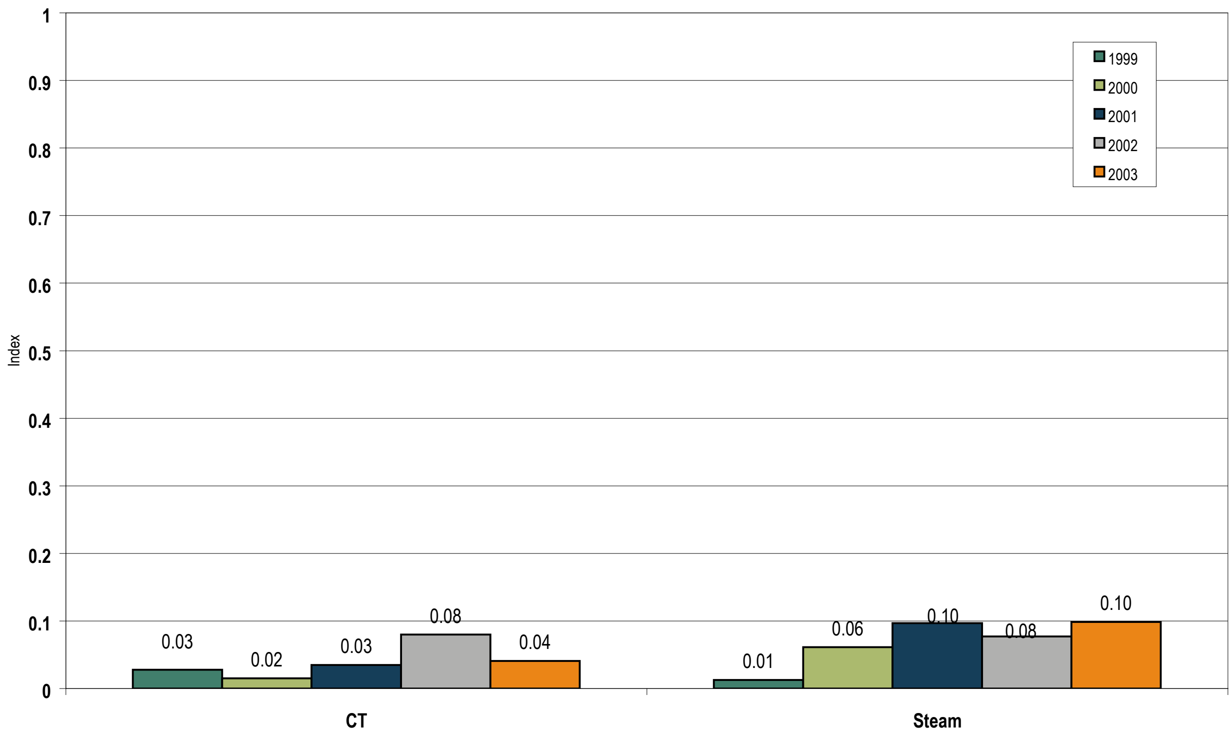


Figure 2-19 shows average markup index by unit type. The average annual markup index diverged somewhat for steam units and CTs. The average annual index decreased for CTs to 4 percent in 2003 from 8 percent in 2002 and increased for steam units to 10 percent from 8 percent in 2002.

Figure 2-19 Average Markup Index by Type of Unit



Overall, the index results presented here are consistent with the conclusion that the Energy Market results were competitive in 2003.

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 incentives to add 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 perfect economic dispatch in the PJM model.[15] Gross energy market revenue is the product of market price and generation output. Gross revenue less variable cost equals net revenue, and Table 2-12 through Table 2-16 illustrate the relationship between net revenue and generation variable cost.

In other words, net revenue is the amount that remains from gross sales revenue, after variable costs, to cover fixed costs, including a return on investment, depreciation, taxes and fixed operations and maintenance expenses.

15 Perfect economic dispatch means that the unit is assumed to be operating whenever hourly LMP exceeds marginal cost and not to be operating whenever LMP is less than marginal cost. Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost. The PJM model also ensures that generators are compensated for start-up and no-load costs when they are dispatched based on marginal costs (i.e., theoretical dispatch) or on their offer price.

Table 2-12 Net Revenues in 1999 by Marginal Cost of Unit

Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year) 1999				
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$152,087	$20,469	$3,444	$176,000
$20	$94,690	$20,469	$3,444	$118,603
$30	$72,489	$20,469	$3,444	$96,402
$40	$62,367	$20,469	$3,444	$86,280
$50	$57,080	$20,469	$3,444	$80,993
$60	$54,132	$20,469	$3,444	$78,045
$70	$52,259	$20,469	$3,444	$76,173
$80	$50,959	$20,469	$3,444	$74,872
$90	$49,840	$20,469	$3,444	$73,753
$100	$48,818	$20,469	$3,444	$72,732
$110	$47,863	$20,469	$3,444	$71,776
$120	$46,926	$20,469	$3,444	$70,839
$130	$46,007	$20,469	$3,444	$69,920
$140	$45,114	$20,469	$3,444	$69,027
$150	$44,228	$20,469	$3,444	$68,141
$160	$43,374	$20,469	$3,444	$67,287
$170	$42,523	$20,469	$3,444	$66,436
$180	$41,685	$20,469	$3,444	$65,598
$190	$40,856	$20,469	$3,444	$64,769
$200	$40,036	$20,469	$3,444	$63,949

Table 2-13 Net Revenues in 2000 by Marginal Cost of Unit

	Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year) 2000			
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$150,774	$23,308	$4,594	$178,676
$20	$89,418	$23,308	$4,594	$117,320
$30	$59,776	$23,308	$4,594	$87,679
$40	$39,519	$23,308	$4,594	$67,421
$50	$25,752	$23,308	$4,594	$53,654
$60	$16,888	$23,308	$4,594	$44,790
$70	$11,750	$23,308	$4,594	$39,652
$80	$8,586	$23,308	$4,594	$36,488
$90	$6,700	$23,308	$4,594	$34,602
$100	$5,640	$23,308	$4,594	$33,542
$110	$4,930	$23,308	$4,594	$32,832
$120	$4,385	$23,308	$4,594	$32,287
$130	$3,958	$23,308	$4,594	$31,860
$140	$3,609	$23,308	$4,594	$31,511
$150	$3,317	$23,308	$4,594	$31,219
$160	$3,102	$23,308	$4,594	$31,004
$170	$2,923	$23,308	$4,594	$30,825
$180	$2,768	$23,308	$4,594	$30,670
$190	$2,623	$23,308	$4,594	$30,525
$200	$2,488	$23,308	$4,594	$30,390

Table 2-14 Net Revenues in 2001 by Marginal Cost of Unit

	Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year)			
	2001			
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$186,887	$36,700	$3,823	$227,411
$20	$116,116	$36,700	$3,823	$156,639
$30	$78,368	$36,700	$3,823	$118,891
$40	$56,055	$36,700	$3,823	$96,578
$50	$42,006	$36,700	$3,823	$82,529
$60	$33,340	$36,700	$3,823	$73,863
$70	$27,926	$36,700	$3,823	$68,450
$80	$24,389	$36,700	$3,823	$64,912
$90	$22,080	$36,700	$3,823	$62,603
$100	$20,521	$36,700	$3,823	$61,044
$110	$19,375	$36,700	$3,823	$59,899
$120	$18,480	$36,700	$3,823	$59,003
$130	$17,716	$36,700	$3,823	$58,239
$140	$17,030	$36,700	$3,823	$57,553
$150	$16,421	$36,700	$3,823	$56,944
$160	$15,884	$36,700	$3,823	$56,407
$170	$15,395	$36,700	$3,823	$55,919
$180	$14,944	$36,700	$3,823	$55,467
$190	$14,542	$36,700	$3,823	$55,065
$200	$14,162	$36,700	$3,823	$54,685

Table 2-15 Net Revenues in 2002 by Marginal Cost of Unit

Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year) 2002				
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$153,620	$11,601	$3,915	$169,135
$20	$85,661	$11,601	$3,915	$101,177
$30	$51,898	$11,601	$3,915	$67,414
$40	$31,650	$11,601	$3,915	$47,166
$50	$19,776	$11,601	$3,915	$35,292
$60	$13,101	$11,601	$3,915	$28,617
$70	$9,080	$11,601	$3,915	$24,596
$80	$6,623	$11,601	$3,915	$22,139
$90	$5,079	$11,601	$3,915	$20,594
$100	$4,109	$11,601	$3,915	$19,625
$110	$3,507	$11,601	$3,915	$19,023
$120	$3,063	$11,601	$3,915	$18,579
$130	$2,758	$11,601	$3,915	$18,274
$140	$2,501	$11,601	$3,915	$18,017
$150	$2,287	$11,601	$3,915	$17,803
$160	$2,115	$11,601	$3,915	$17,631
$170	$1,970	$11,601	$3,915	$17,486
$180	$1,828	$11,601	$3,915	$17,344
$190	$1,700	$11,601	$3,915	$17,216
$200	$1,607	$11,601	$3,915	$17,123

Table 2-16 Net Revenues in 2003 by Marginal Cost of Unit

	Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year)			
	2003			
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$213,211	$5,936	$3,880	$223,027
$20	$147,516	$5,936	$3,880	$157,333
$30	$101,922	$5,936	$3,880	$111,738
$40	$68,531	$5,936	$3,880	$78,347
$50	$44,150	$5,936	$3,880	$53,966
$60	$27,810	$5,936	$3,880	$37,626
$70	$17,097	$5,936	$3,880	$26,914
$80	$10,205	$5,936	$3,880	$20,021
$90	$6,079	$5,936	$3,880	$15,896
$100	$3,697	$5,936	$3,880	$13,513
$110	$2,226	$5,936	$3,880	$12,042
$120	$1,305	$5,936	$3,880	$11,121
$130	$722	$5,936	$3,880	$10,538
$140	$387	$5,936	$3,880	$10,203
$150	$218	$5,936	$3,880	$10,034
$160	$141	$5,936	$3,880	$9,958
$170	$94	$5,936	$3,880	$9,910
$180	$51	$5,936	$3,880	$9,867
$190	$23	$5,936	$3,880	$9,840
$200	$10	$5,936	$3,880	$9,826

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 Capacity, Energy and Ancillary Service Markets are all 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.

The approach to the theoretical net revenue calculation has been modified in this report in several ways from prior "State of the Market" reports. This altered approach has been applied to each year from 1999 through 2003 to create a consistent set of results. The modifications to the net revenue analysis include the use of forced outage rates, elimination of operating reserve revenues and inclusion of ancillary service revenues from the provision of reactive and black start services. Use of forced outage rates reduces net revenues because it assumes that units are not available to run even when it was profitable to operate. Elimination of operating reserve revenues also reduces net revenues. The inclusion of ancillary service revenues from reactive and black start services increases net revenues.

Net revenue calculations presented in Table 2-12 through Table 2-16 reflect net revenues from Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services during the study years 1999 to 2003. The tables illustrate 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 levels in dollars per MWh adjusted for outages. The net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each study year. For example, during 2003, 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 2003, it would have received $111,738 per MW in net revenue from all sources, with the Energy Market contributing $101,922, the Capacity Market contributing $5,936 and ancillary service revenues contributing $3,880.

The net revenue data are approximate measures, generally representing an upper bound of the markets' direct contribution to generator fixed costs. The net revenue curve does not take account of operating constraints that may affect the actual net revenues of individual plants. For example, for a typical summer weekday, a six-hour hot status notification plus start-up time for a combined-cycle steam plant 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 four unprofitable hours. A combustion turbine with a limit of one start per day would also not be available for both an afternoon and an evening peak. As another example, ramp limitations might prevent a unit from starting and ramping up to full output in time to operate for all profitable hours.

In addition, the net revenue measure accounts for neither the profitability of a portfolio of generation assets nor the contribution to fixed costs from the option value of physical units, which can be considerable.

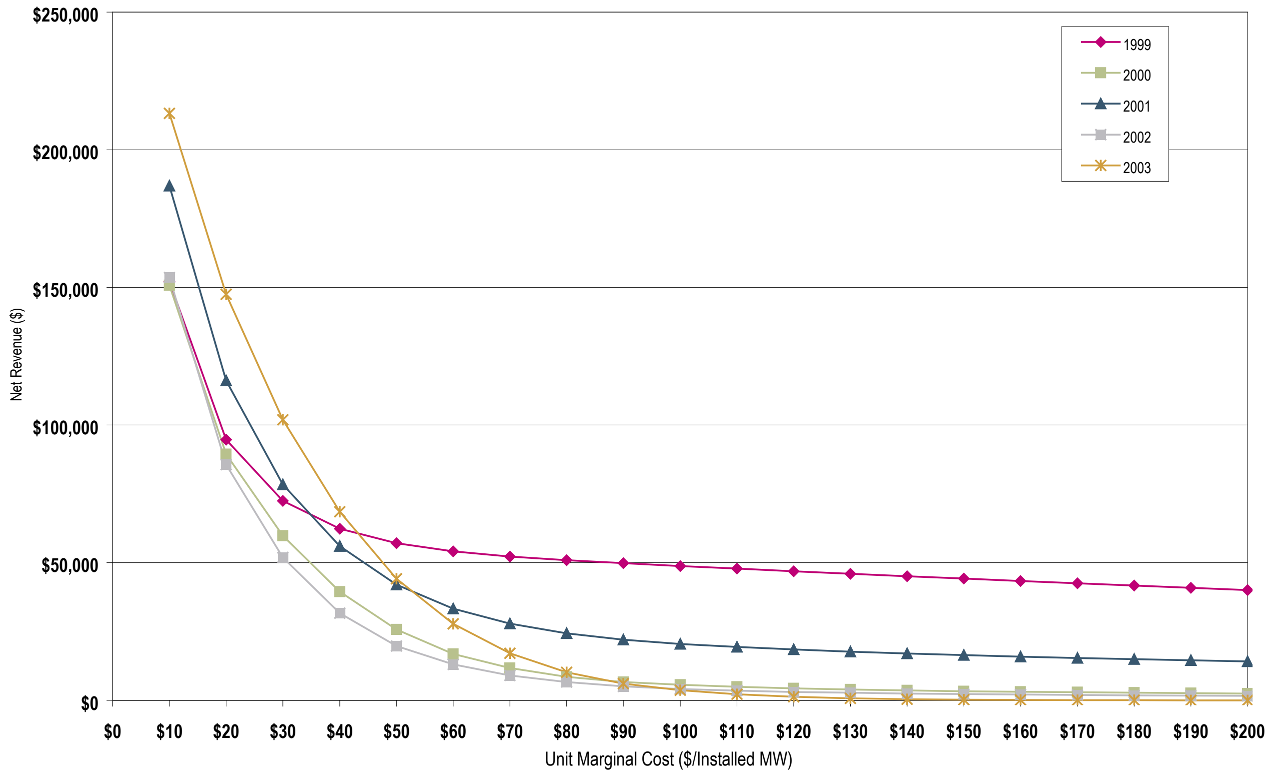
Energy Market Net Revenue

As Figure 2-20 illustrates, the energy market net revenue curve was higher in 2003 for units with marginal costs equal to or less than $40 and lower for those with marginal costs above $100 than for any year from 1999 through 2002. As a result, units with low marginal costs were more profitable in 2003 than in prior years. If a unit with marginal costs of $30 per MWh had operated during all hours when the LMP exceeded $30 per MWh, it would have received about $72,000 per installed MW in net energy revenue in 1999, about $60,000 in 2000, about $78,000 in 2001, about $52,000 in 2002 and about $102,000 in 2003.

The large increase in energy revenue for 2003 compared to earlier years results from a change in LMP frequency distribution. In 1999, the frequency of LMP equal to or less than $30 was 83 percent and of LMP equal to or less than $20 was 60 percent. In 2000, the frequencies were 71 percent and 54 percent, respectively; in 2001, the frequencies were 66 percent and 39 percent, respectively; in 2002, the frequencies were 70 percent and 45 percent, respectively and in 2003, the frequencies were 49 percent and 27 percent, respectively. Consequently, there were more hours with LMPs above $30 in 2003 than in any year since the introduction of PJM Markets.

The 2003 load-weighted LMP averaged $41.23 per MWh compared to $31.60 in 2002, $36.65 in 2001, $30.72 in 2000 and $34.06 in 1999. In contrast to earlier years, however, 2003 did not have any price spikes. In 2003 LMP exceeded $200 for only one hour, compared to nine hours in 2002, 40 hours in 2001, 15 hours in 2000 and 86 hours in 1999. As a result, units with high marginal costs were not as profitable in 2003 as in prior years. In 1999, if a unit with marginal costs of $100 per MWh had operated during all hours when LMP exceeded $100 per MWh, it would have received about $49,000 per installed MW in net energy revenue versus about $6,000 in 2000, about $21,000 in 2001, about $4,000 in 2002 and less than $4,000 in 2003.

Figure 2-20 PJM Energy Market Net Revenue: 1999, 2000, 2001, 2002 and 2003



Differences in the shape and position of net energy revenue curves for the five years result from different distributions of energy market prices. These differences illustrate the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units. Although average prices in 2000 were approximately equal to average prices in 1999, hourly average prices in 2000 were actually higher than hourly average prices in 1999 for all intervals except hours 1200 through 1800, when 1999 prices significantly exceeded those in 2000. These peak hours included intervals when 1999 prices spiked to more than $900 per MWh for a limited number of hours. The 91 hours in 1999 when prices exceeded $150 per MWh and the 43 hours when prices exceeded $800 per MWh generally occurred during these peak intervals. These periods were responsible for the shape of the 1999 net revenue curve. In 2000, there were only 27 hours when prices exceeded $150 per MWh and only one hour when prices exceeded $800 per MWh. The limited number of high-priced hours in 2000 resulted in lower net revenue for units operating at marginal costs above $30 per MWh. In 2003, LMP exceeded $150 for only 11 hours compared to 20 hours in 2002, and during only one hour in 2003 did prices exceed $200, reaching a maximum of $211. In 2002, prices had been above $200 for nine hours and had reached a maximum of $791. Conversely, price was less than $10 for 241 hours in 2003 compared to 195 hours in 2002.

Capacity Market Net Revenue

In addition to energy-related revenue, generators receive revenues for capacity. In 2003, PJM capacity resources received a weighted-average payment from the PJM Capacity Credit Markets of $17.51 per MW-day, or $5,936 per MW of installed capacity for the year. The 2003 results represent a significant reduction from the 2002 Capacity Market revenues of $33.40 per MW-day or $11,601 per installed MW of capacity. The PJM Mid-Atlantic and PJM Western Regions had different Capacity Market designs from April 1, 2002 (the date of the PJM Western Region's integration), until June 1, 2003 (the date of the PJM Western Region Capacity Market's merger with the Mid-Atlantic Region Capacity Market). However, since there was no effective market in the Western Region, its capacity market prices did not represent market-clearing value transactions. The capacity value used in the net revenue calculations is the Mid-Atlantic market value through May 31, 2003, and the integrated PJM market value thereafter.[16]

Ancillary Service and Operating Reserve Net Revenue

Under the terms of the PJM tariff, generators also receive revenues for providing ancillary services, including those from the Spinning Reserve and Regulation Markets and from black start and reactive services. Aggregate ancillary revenues were $3,880 per installed MW-year in 2003 versus $3,915 per installed MW-year in 2002.

Although not included in the theoretical net revenue analysis above based on the assumption of perfect economic dispatch, generators also received operating reserve revenues from both the Day-Ahead and Balancing Energy Markets. Operating reserve payments were about $3,500 per installed MW-year in 2003 and $3,000 per installed MW-year in 2002. These payments, in part, ensure that generators are guaranteed accepted bid revenues from units scheduled by PJM, including the payment of start-up and no-load costs.

New Entrant Combustion Turbine/Combined-Cycle Net Revenue

An analysis of the theoretical net revenues available for a new combustion turbine (CT) or combined-cycle (CC) market entrant was performed to calculate the potential net revenues available. This calculation represents the upper bound of net revenue since it assumes perfect economic dispatch. For analysis purposes, the CT and CC heat rates were 10,500 Btu per kWh and 7,000 Btu per kWh, respectively, with a variable operations and maintenance (VOM) expense of $3 per MWh for the CT and $1 per MWh for the CC plant. The heat rate and VOM estimates were established by utilizing data from original equipment manufacturers (OEM) and available market data. The burner tip fuel cost was determined by utilizing the published Platt's commodity daily cash price for natural gas with a basis adjustment to account for transportation costs. Forced outage rates of 2.5 percent and 5.4 percent for the CT and CC, respectively, were used in this analysis. These outage rates are based upon OEM estimates for new facilities. Operating reserve payments are not included since the analysis represents perfect economic dispatch where marginal cost is equal to or less than system average LMP and, therefore, no operating reserve payments would be necessary. The summary of the potential net revenue streams for 1999 to 2003 are shown in Table 2-17 for a new CT and a new CC, both burning natural gas. These net revenue figures do not take account of operating constraints. For example, for a typical summer weekday, a six-hour hot status notification plus start-up time 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 four unprofitable hours, or a combustion turbine with a limit of one start per day might not be available for the evening peak from the above example. As another example, ramp limitations might prevent a unit from starting and ramping up to full output in time to operate for all profitable hours.

16 See Section 4, "Capacity Markets," for further details.

Table 2-17 New Entrant Combustion Turbine and Combined-Cycle Plant Theoretical Net Revenues

Economic Dispatch Generic CT and CC Net Revenue Streams ($ per Installed MW - Year) Gas-Fired								
Year	CT Energy	CC Energy	Capacity	Ancillary	CT Total	CC Total	CT Run Hours	CC Run Hours
2003	$15,380	$53,743	$5,936	$3,880	$25,196	$63,559	964	2,791
2002	$27,626	$57,148	$11,601	$3,915	$43,142	$72,664	1,383	3,206
2001	$44,481	$74,831	$36,700	$3,823	$85,004	$115,354	1,373	3,507
2000	$19,876	$45,236	$23,308	$4,594	$47,779	$73,138	926	2,201
1999	$73,480	$97,603	$20,469	$3,444	$97,393	$121,516	1,415	4,199

Table 2-18 Burner Tip Average Fuel Price in PJM (in Dollars per MBtu)

Average Burner Tip Fuel Price (Dollars per Mbtu)	
Year	Natural Gas
2003	$6.45
2002	$3.81
2001	$4.52
2000	$5.18
1999	$2.62

Total Net Revenue

To put the net revenue results in perspective, the average gas cost in PJM in 2003 was about $6.45 per MBtu (Table 2-18) and the corresponding variable cost for a new combustion turbine was, on average, between $70 and $75 per MWh.[17] On average, the corresponding variable cost for a new combined-cycle unit was between $45 and $50 per MWh.[18] According to OEM and available market data, annual fixed costs for a new CT averaged approximately $68,000 per MW-year from 1999 to 2003 while a new CC plant averaged approximately $78,000 per MW-year over the same period.[19] Current annual fixed costs for a CT are somewhat higher than the CDR calculations of such costs of about $63,000 per MW-year.[20] The capacity costs of a new CT constructed in New England in 2001 was recently estimated to be $73,800 per MW-year.[21]

In 2003, net revenues from the Energy Market, the Capacity Market and ancillary services for a new entrant CT were approximately $25,200 and the associated operating costs were between $75 and $80 per MWh. These figures are based on a heat rate of 10,500 Btu per kWh, daily delivered natural gas prices that averaged $6.45 per MBtu and a variable operations and maintenance (VOM) rate of $3 per MWh. The net revenue stream would not have covered the fixed costs of peaking units with operating costs between $75 and $80 per MWh which ran during all profitable hours.

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

18 The key variables are fuel cost and heat rate.

19 The fixed costs in 2003 were somewhat less. The fixed costs for a CT were $65,600 and the fixed costs for a CC were $76,400

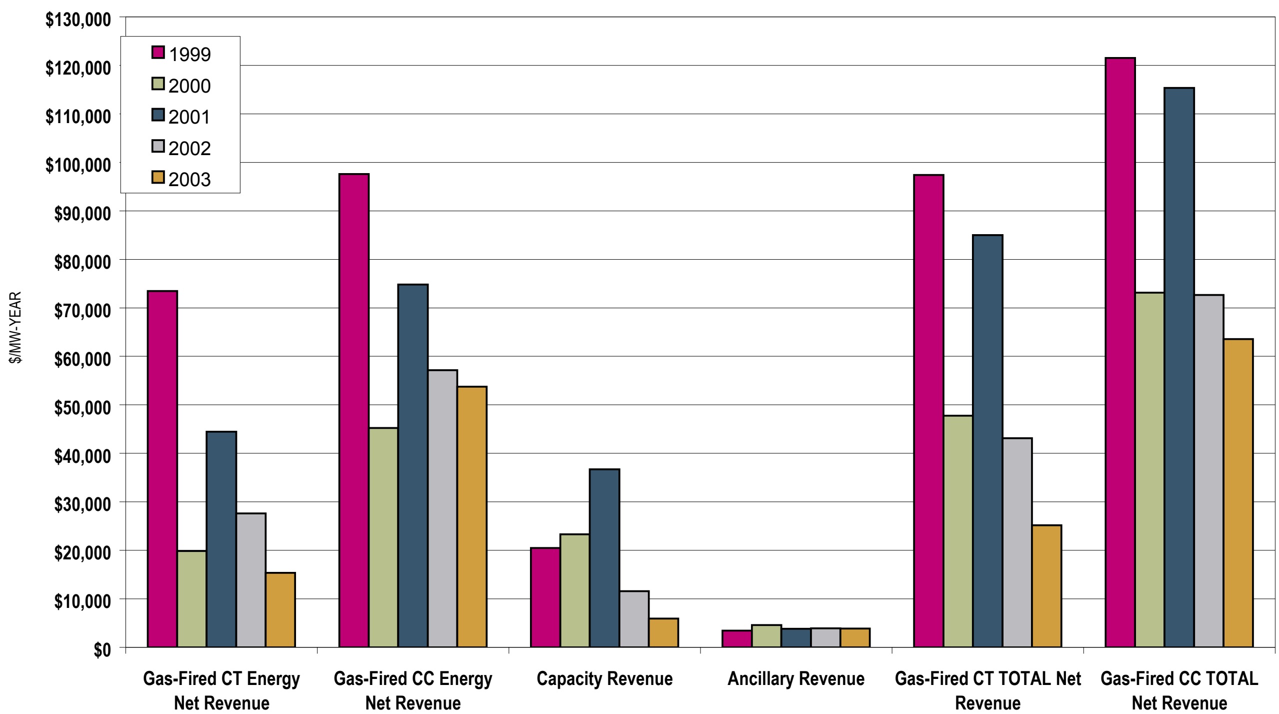
20 The CDR was designed to reflect the annual fixed costs of a CT in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense. The CDR also includes, as an offset, an energy credit of about $4,500 per MW-year designed to reflect the difference between the PJM dispatch rate and CT costs during the hours when the CTs run. The CDR was calculated in 1997. Thus the annual fixed cost of a CT in PJM, per CDR calculations, is about $63,000 per MW-year.

21 Acumen, Inc., "Final Report to ISO New England," December 10, 2001.

For a new entrant CC, the 2003 net revenue stream was approximately $63,600 and the associated operating costs were between $45 and $50 per MWh. These figures are based on a heat rate of 7,000 Btu per kWh, daily delivered natural gas prices that averaged $6.45 per MBtu and a variable operations and maintenance (VOM) rate of $1 per MWh. As with the case with the new entrant CT, this net revenue stream would not have covered the fixed costs of a CC plant with operating costs between $45 and $50 per MWh which ran during all profitable hours.

In 1999 and 2001 the calculated theoretical net revenue as shown in Table 2-17 for CT and CC plants was sufficient to cover the average fixed costs of $68,000 per installed MW-year and $78,000 per installed MW-year, respectively, while there was a revenue shortfall for 2000, 2002 and 2003. Five-year theoretical net revenue averaged $59,700 per installed MW-year for new entrant CT plants and $89,200 per MW-year for new entrant CC plants. Therefore, under theoretical conditions over the five-year period, net revenue was not adequate to cover CT fixed costs, but was more than adequate to cover the fixed costs of new entrant CC plants. The conclusion regarding both CT and CC plants depends on the actual fixed costs of such plants. While the net revenue calculations accurately reflect the stated assumptions, to the extent that annual fixed costs are higher than the estimate used here, the conclusion may be affected.

Figure 2-21 Theoretical New Entrant Combustion Turbine and Combined-Cycle Plant Yearly Net Revenue



Although it can be expected that in the long run, in a competitive market, net revenues from all sources will cover the fixed costs of investing in new generating resources, including a return on investment, actual results may vary from year to year. Revenues from the Capacity Market and the provision of ancillary services clearly vary from unit to unit, depending on particular capacity market transactions and the provision of specific ancillary services. The MMU's analysis of 2003 net revenues indicates that the fixed costs of a marginal unit were not fully covered. 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.

Net revenues provide an incentive 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 2003, about 15,200 MW of capacity were in generation request queues for construction through 2008 (Figure 2-22), compared to an average installed capacity of 71,473 MW in 2003. Although it is clear that not all of this generation will be completed, PJM is steadily adding capacity. Figure 2-23 shows the level of capacity that is in service and the level that has been withdrawn from the queues.

Figure 2-22 Queued Capacity by In-Service Date

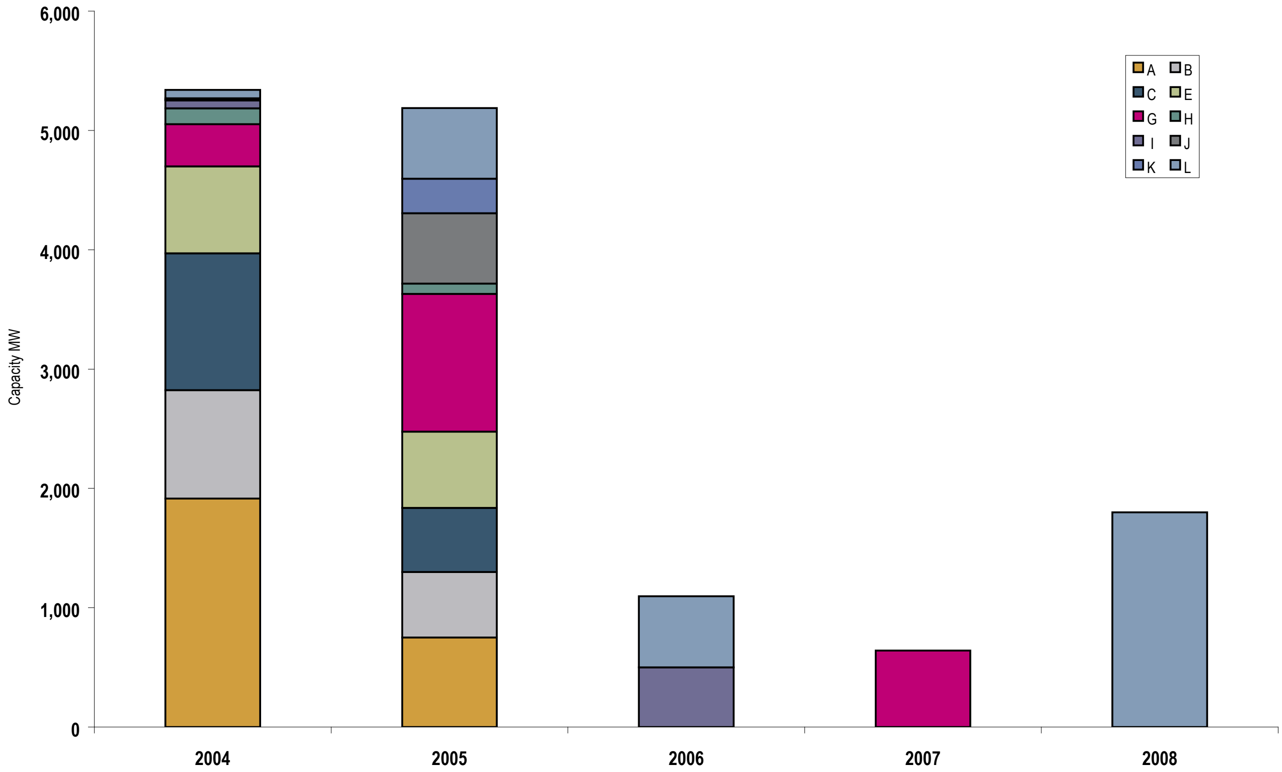
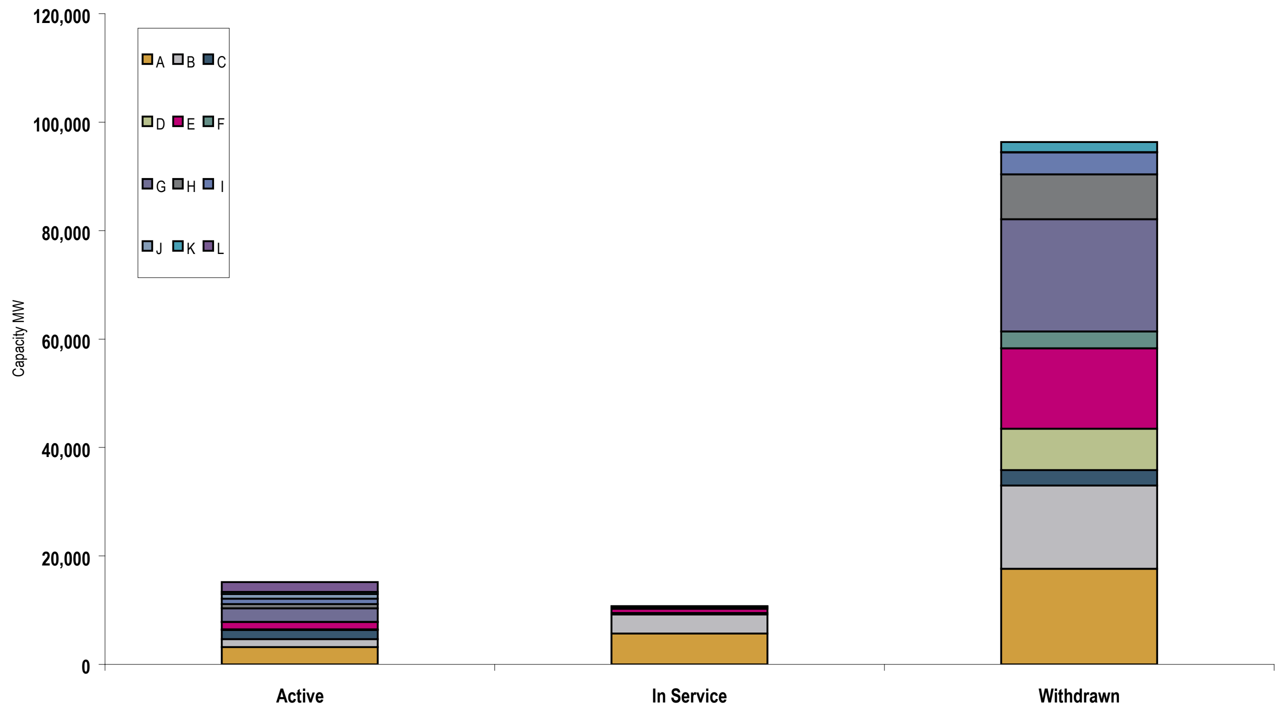


Figure 2-23 New Capacity in PJM Queues through December 31, 2003



Operating Reserve Payments

Operating reserve payments are made to resource owners under specified conditions in order to ensure that units are not required to operate for PJM at a loss. These payments provide an incentive to generation owners to offer their energy to the PJM Market at marginal cost and to operate their units at the direction of PJM dispatchers. If a unit is selected to operate in the PJM Day-Ahead Market on the basis of its offer and the revenues in the Energy Market are insufficient to cover all the components of that unit's offer, including start-up and no-load offers, operating reserve payments ensure that all costs offer components are covered[22].

Table 2-19 shows total operating reserve payments from 1999 through 2003. A number of significant market changes have occurred during this period. Energy Markets clearing on the basis of market-based generator offers were initiated on April 1, 1999. Thus the 1999 operating reserve total includes operating reserve payments for three months based on generators' marginal cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Market opened on June 1, 2000. Thus operating reserve payments for 1999 and the first five months of 2000 include only operating reserve payments made in the Balancing Market. Beginning on June 1, 2000, operating reserve payments include both day-ahead and balancing operating reserve payments. As Table 2-19 shows, between 2001, the first full year of two settlement operation, and 2002, operating reserve payments declined by about $62 million, or 25 percent. Between 2002 and 2003, operating reserve payments rose by approximately $85 million or 45 percent. Table 2-19 also shows the ratio of total operating reserve payments to the total value of PJM market billings. Over the last five years, the operating reserve payments ranged from a low of 3.0 percent in 1999 to a high of 7.5 percent in 2001; they were 4.0 percent in both 2002 and 2003.

Table 2-19 Total Day-Ahead and Balancing Operating Reserve Payments

	PJM Day-Ahead and Balancing Operating Reserve Payments	
Year	Annual Payment	Annual Payment Change
2003	$274,489,178	45.1%
2002	$189,114,344	-24.8%
2001	$251,583,885	71.3%
2000	$146,841,525	172.5%
1999	$53,886,408	----

Table 2-20 shows day-ahead and balancing operating reserve total payments and payments per MWh. Per MWh rates are calculated for each full year after the introduction of the Day-Ahead Market. The day-ahead billing determinant (denominator of the day-ahead rate) is the sum of the day-ahead demand plus accepted decrement bids plus exports. The balancing market billing determinant is the sum of the load, generation and transaction deviations from the Day-Ahead Market. In this context, transaction deviations include deviations that result from cleared virtual bids or offers from the Day-Ahead Market that were not subsequently delivered in the Balancing Market. The day-ahead operating reserve rate was lower in 2003 than in 2001 and the real-time operating reserve rate was higher in 2003 than in 2001.

22 Operating reserve payments are also made for pool-scheduled energy transactions, for generating units operating as condensers not for spinning reserves, for the cancellation of pool-scheduled resources, for units backed down for reliability reasons and for units providing quick start reserves.

Table 2-20 Day-Ahead and Balancing Operating Reserve Rates

Year	Annual Payment	Annual Payment Change	Operating Reserves as a Percent of Total PJM Billing
2003	$274,489,178	45.1%	4.0%
2002	$189,114,344	-24.8%	4.0%
2001	$251,583,885	71.3%	7.5%
2000	$146,841,525	172.5%	6.5%
1999	$53,886,408	----	3.0%

For each year from 2001 to 2003, total day-ahead and balancing operating reserve payments for the top-10 generating units were compared to the system total. As Table 2-21 shows, in 2001 the top-10 units represented 46.6 percent of total operating reserve payments. For 2002, the percentage dropped to 32.0 percent. For 2003, payments to the top-10 units represented 39.2 percent of total operating reserve payments. A relatively small number of generation owners accounted for a substantial proportion of total operating reserve payments in each year from 2001 through 2003.

Table 2-21 Top-10 Operating Reserve Revenue Units

	Percent of System Total		
	2003	2002	2001
Top Units	39.2%	32.0%	46.6%

A unit is eligible to receive operating reserve payments when it is selected by PJM in the Day-Ahead Energy Market and when its corresponding revenues are not sufficient to cover its offer value. In addition, if a generator is scheduled for operation in the Balancing Market and it operates as directed by PJM dispatchers, it is eligible to receive operating reserve payments when its corresponding revenues are not sufficient to cover its offer. The operating reserve payments act as a revenue guarantee for generators in order to provide an additional incentive to participate in the voluntary PJM scheduling and dispatch process.

The level of operating reserves payments made to specific units depends on the offer level of the units, unit operating parameters and the decisions made by PJM operators when scheduling generation in excess of demand.

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. It calculated the markup using the formula [(Price – Cost)/Price] at the relevant operating point on the supply curve for each unit. As Table 2-22 shows, the markup for the top-10 units averaged 0.03 in 2001, 0.11 in 2002 and 0.17 in 2003. The markup for the top-10 units weights individual unit markup by generator output when operating reserves are paid. The markup rose from 2001 through 2003 despite a decline in the share of operating reserves paid to the top-10 units over that period. The increased markup resulted from higher company and unit-specific markups combined with increased hours during which PJM dispatched the higher markup units out of merit order. In 2001, the top-10 units had price offers much closer to their respective cost offers. As a comparison, the PJM system overall weighted-average markup was 0.02 in 2001, 0.02 in 2002 and 0.03 in 2003.

Table 2-22 Top-10 Operating Reserve Revenue Units' Markup

	Markup		
	2003	2002	2001
Top Units	0.17	0.11	0.03

Operating reserve payments also result from 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, or has a 24-hour minimum run time and a minimum shutdown or long start time, then it receives higher operating reserve payments than if those operating parameters were not in place. Restrictive operating parameters can interact with unit-specific markups to increase operating reserve payments to units.

Operating reserve payments ultimately result from decisions of PJM operators to keep units operating even though the hourly LMP is less than their offer price, including the energy offer, start-up offer and no-load offer. These PJM decisions also interact with the level of the markup and the operating parameters to affect operating reserve payments to units.

The MMU will continue to examine the various factors underlying operating reserve payments. The reasons that a relatively small number of generation owners account for a substantial proportion of total operating reserve payments will be examined. The role of unit-specific, price-cost markups will be examined. The role of restrictive operating parameters will be examined. Finally, the role of PJM operations in contributing to overall operating reserve payment levels and to operating reserve payments to the top-10 units will be examined to ensure that PJM is operating in an efficient manner. The MMU will also examine the other rules governing operating reserve payments, including the requirement that they be based on a 24-hour average of LMP revenues and offers.

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.[23]

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 in long-run equilibrium, prices are directly related to the cost of the marginal 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 pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus illustrates the potential significance of price elasticity of demand in affecting price.

Real-Time Energy Market Prices

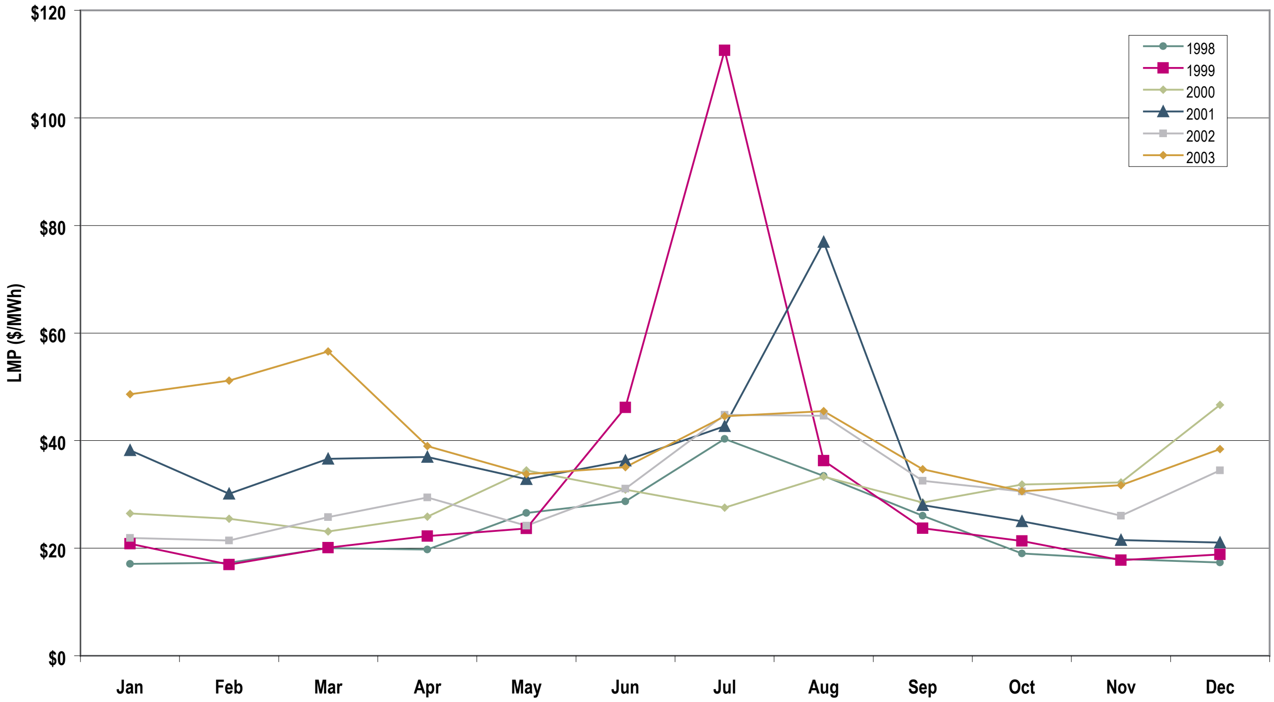
PJM real-time energy market prices increased in 2003. The simple hourly average system LMP[24] was 35.2 percent higher in 2003 than in 2002, $38.27 per MWh versus $28.30 per MWh. The average LMP in 2003 was higher than in all previous years since the introduction of markets in PJM. When hourly load levels are reflected, the load-weighted LMP of $41.23 per MWh in 2003 was 30.5 percent higher than in 2002, 12.5 percent higher than in 2001 and 34.2 percent higher than in 2000. The load-weighted result reflects the fact that market participants typically purchase more energy during high-priced periods and that peak-period prices are generally higher. In 2003, summer peak loads and prices were lower than in 2002, and in 2003 the highest prices occurred in the winter period. When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted average LMP in 2003 was 9.5 percent lower than in 2002, $28.60 per MWh compared to $31.60 per MWh. Thus, after accounting for both the actual pattern of loads and the increased costs of fuel, average prices in PJM were 9.5 percent lower in 2003 than in 2002.

The annual increase in PJM system average LMP was significantly affected by prices in the first quarter. Prices in the first quarter of 2003 were much higher than in the first quarter of 2002. In the first quarter of 2003, average load-weighted, real-time LMP was $29.09 per MWh higher, or 127 percent, than during the comparable 2002 period. Load-weighted average LMP was $51.92 per MWh in the first quarter of 2003 and $23.02 per MWh in the first quarter of 2002 (Figure 2-24). As an illustration of the impact of first quarter results, if the first quarter 2003 LMPs had been the same as first quarter 2002 LMPs, the annual load-weighted LMP for 2003 would have been $34.44 per MWh (the actual was $41.23), or 9 percent higher than in 2002 (the actual increase was 30.5 percent).

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

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

Figure 2-24 Monthly Load-Weighted Average LMP (by Year)



Two principal factors contributed to the higher first quarter LMPs:

- **Marginal Fuel Prices.** A combination of higher natural gas prices and an increase in the proportion of hours that natural gas served as the marginal fuel contributed to higher first quarter prices. Natural gas prices increased 200 percent on average during the first quarter of 2003 as compared to the first quarter of 2002.

  Figure 2-25 shows average typical daily natural gas prices for units within PJM.[25] The price of No. 6 fuel oil also increased nearly 100 percent during the first quarter of 2003. Higher fuel costs have an impact on LMP only when units burning those fuels are on the margin. In the first quarter of 2003, in conjunction with the fuel price increases, units burning the more expensive fuels were on the margin, and thus set LMP more frequently. Units burning natural gas were on the margin 27 percent of the time in the first quarter of 2003, about twice as frequently as the 14 percent they had been on the margin during the same period in 2002. Oil burning units were on the margin nearly three times as frequently in the first quarter 2003 as in 2002, 17 percent and 6 percent, respectively. Correspondingly, the percentage of time that coal units were marginal decreased from 79 percent in 2002 to 55 percent in 2003. The cost of fuels affects the shape of the supply curve. The interaction of demand with that supply curve determines market prices.[26] Units burning natural gas and oil were on the margin more frequently in the first quarter of 2003 than in the first quarter of 2002 because demand for electricity was higher.

- **Demand.** On average, for all of 2003, load increased 5 percent over the 2002 load. However, load for the PJM Mid-Atlantic Region was nearly 10 percent higher in the first quarter of 2003 than in the first quarter of 2002. For the remainder of the year, load was nearly 2.5 percent less overall in 2003 than 2002 (Figure 2-26). As an illustration, if the first quarter 2003 load had been the same as the first quarter 2002 load, then overall average load for 2003 would have been 1.9 percent less than in 2002. Demand for electricity is a function of the weather. The winter period of 2002 (December 2001 through February 2002) was one of the warmest on record. In contrast, temperatures during the winter of 2003 (December 2002 through February 2003) were below normal. According to the National Climactic Data Center, average temperatures in the Northeast were nearly 13 degrees cooler in January 2003 than in January 2002, nine degrees cooler in February 2003 than in February 2002 and about the same in March for both years.

25 Natural gas prices are the average of the daily cash price for Transco, Z6, non-New York and Texas Eastern, M-3.

26 .Analysis of unit outage data showed no differences between the first quarter of 2003 and the first quarter of 2002.

Figure 2-25 Natural Gas Cash Prices

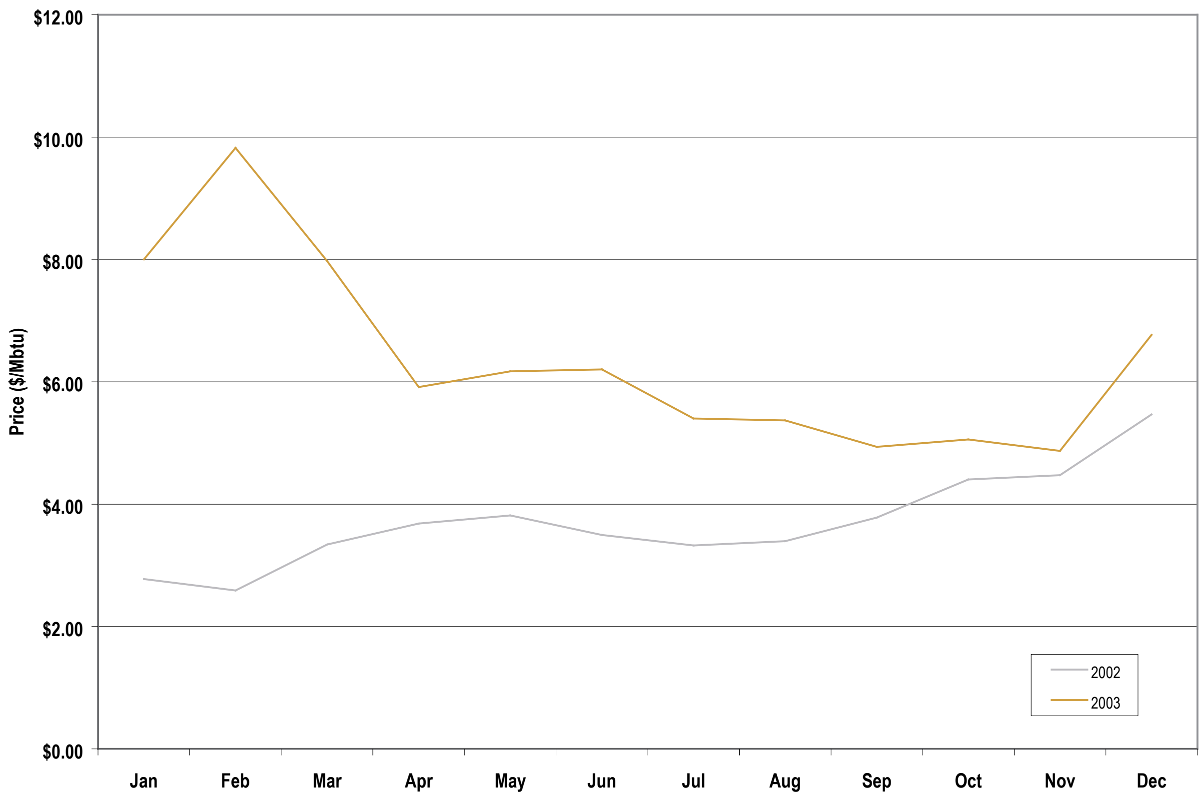
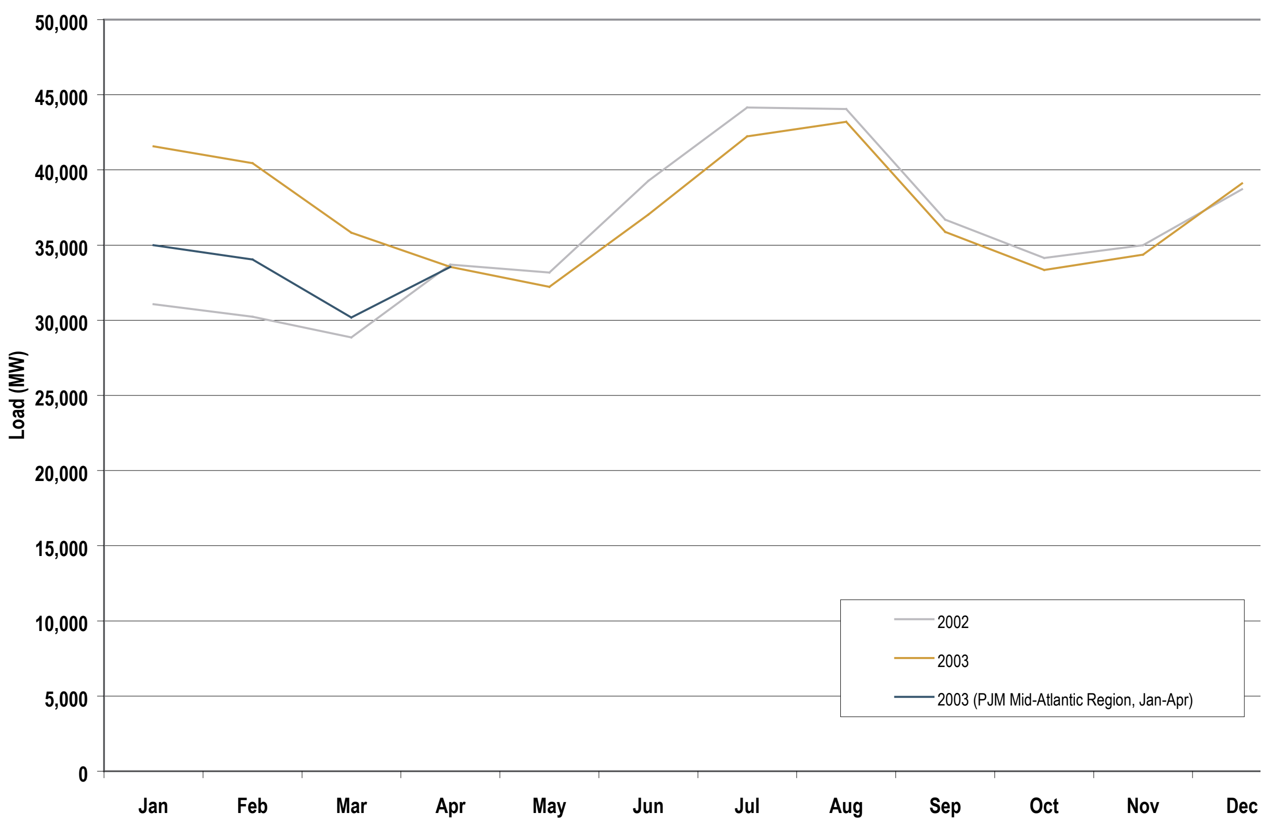


Figure 2-26 PJM Average Monthly Load



Average Hourly, System Unweighted LMP

At $38.27 per MWh, the average hourly, system unweighted LMP for 2003 was 35.2 percent higher than for 2002 (Table 2-23).[27]

Table 2-23 PJM Average Hourly Locational Marginal Prices (in Dollars per MWh)

	Locational Marginal Prices (LMP)			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
2003	$38.27	$30.79	$24.71	35.2%	46.0%	10.3%
2002	$28.30	$21.08	$22.40	-12.6%	-8.3%	-50.6%
2001	$32.38	$22.98	$45.30	15.1%	20.3%	76.3%
2000	$28.14	$19.11	$25.69	-0.6%	6.9%	-64.5%
1999	$28.32	$17.88	$72.41	30.4%	7.7%	130.2%
1998	$21.72	$16.60	$31.45			

Price Duration

For 2003, prices were above $150 per MWh for only 11 hours, with the maximum LMP of $210 per MWh occurring on February 26.

While prices during most hours generally reflect the interaction of demand and energy offers, prices on high load days may reflect a combination of market power and scarcity. In 2002, however, the additional capacity provided by the PJM Western Region and new capacity built in the rest of PJM caused a downward shift in the supply curve and a shifting to the right of the upward sloping portion of the supply curve. In 2003, the shape of the supply curve remained generally the same as in 2002, with the exception of the first quarter of the year. In the first quarter, the flat portion of the curve shifted higher because of the rise in fuel costs. As in 2002, the shape of the supply curve combined with the level of demand meant that there were relatively few hours when scarcity existed or when there was an opportunity to exercise market power

Figure 2-27 compares the PJM system price duration curves for 1998, 1999, 2000, 2001, 2002 and 2003. A price duration curve shows the percent of hours that LMP was at or below a given price for the year. Figure 2-27 shows relatively little difference in LMPs for nearly 70 percent of the hours in each of the previous five years. The 2003 price duration curve shows higher prices for 2003 over a substantial portion of the curve. Figure 2-28 compares price duration curves for hours above the 95th percentile. Figure 2-28 shows that in all years, prices generally exceeded $100 per MWh between 1 and 2 percent of the hours. In 2003, despite overall higher LMPs, the price duration curve remained relatively flat in comparison to previous years, with LMPs never reaching higher than $210 per MWh.

Figure 2-27 and Figure 2-28 show that LMP exceeded $900 per MWh in 1998, 1999 and 2001. For 1998 and 1999, prices were greater than $900 per MWh for a total of 35 hours during the hot summer months. In 2001, prices rose to more than $900 per MWh for 10 hours during the week of August 6 when a new peak demand was set. Prices in 2002 never exceeded $800 per MWh, exceeded $700 per MWh for only one hour and exceeded $150 per MWh for 20 hours. Prices in 2003 exceeded $200 per MWh for only one hour and exceeded $150 per MWh for a total of 11 hours.

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

Figure 2-27 PJM Price Duration Curves – Real-Time Market: 1998 - 2003

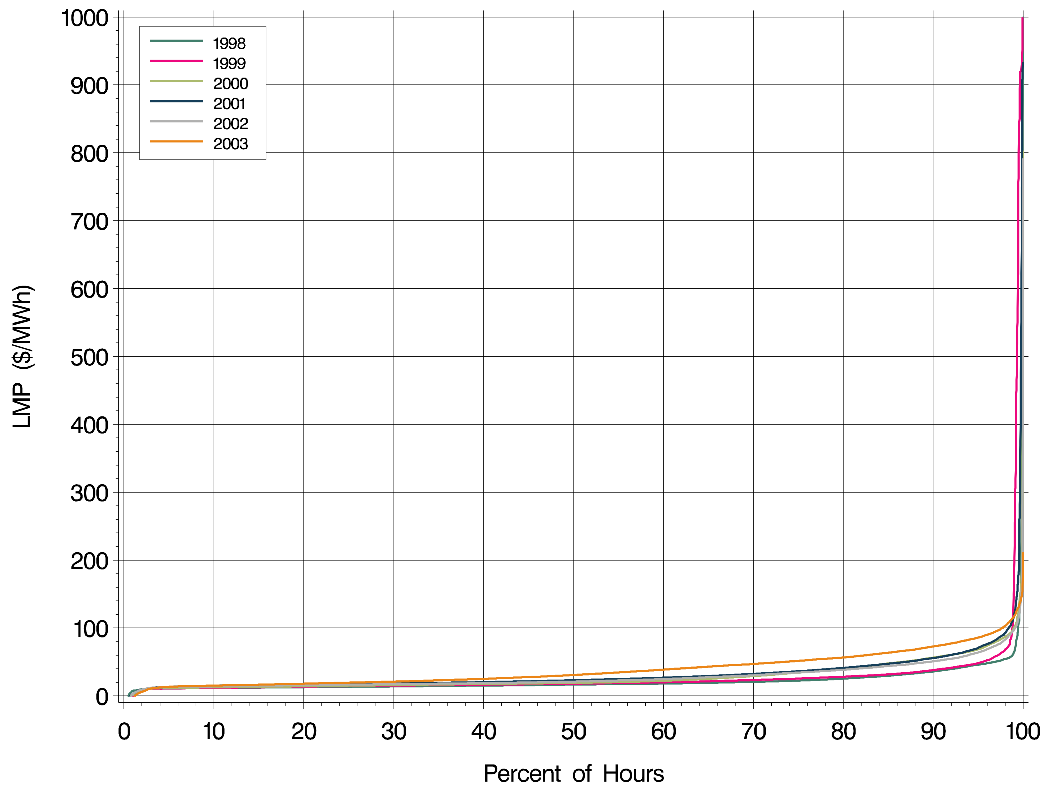
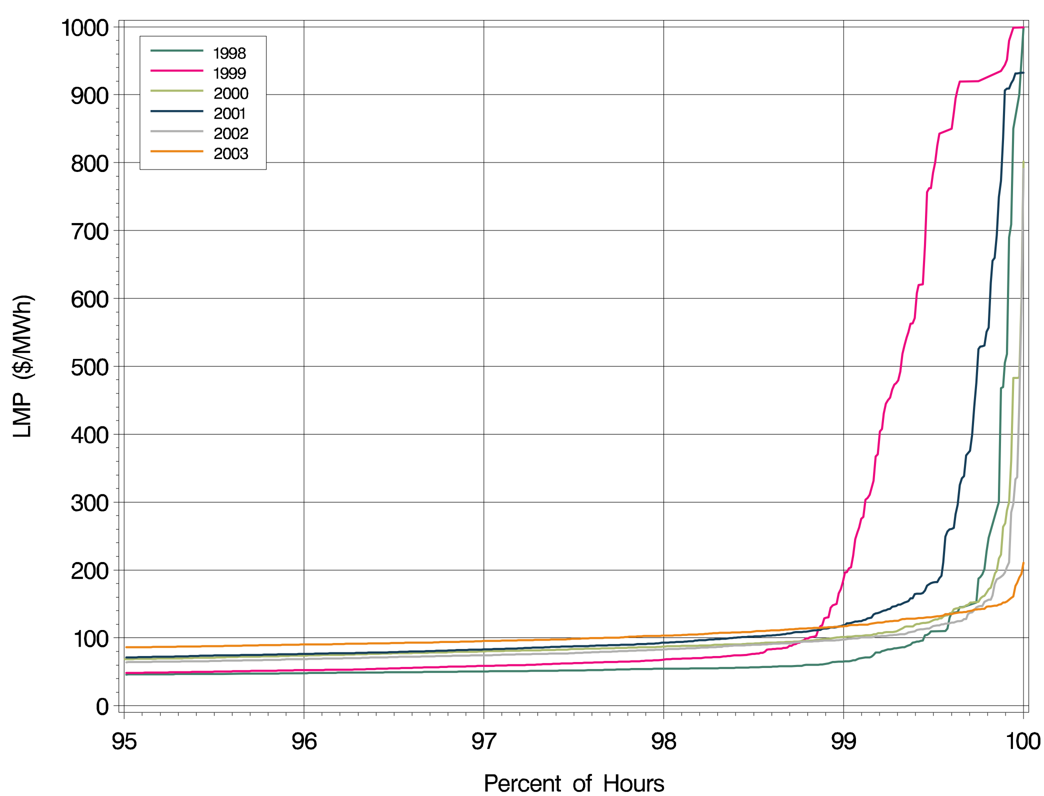


Figure 2-28 PJM Price Duration Curves – Real-Time Market – Hours above the 95th Percentile: 1998 - 2003



Load

Table 2-24 presents summary load statistics for the six-year period 1998 to 2003. The average load of 37,395 MW in 2003 was 5.2 percent higher than in 2002, reflecting colder than usual temperatures in the first quarter of 2003. In the first quarter of 2003, load for the PJM Mid-Atlantic Region was nearly 10 percent higher than in the first quarter of 2002. For the remainder of the year, however, PJM load was about 2.5 percent less in 2003 than in 2002[28] (Figure 2-26). The variability of load, as measured by the standard deviation, was lower in 2003 than in 2002.[29]

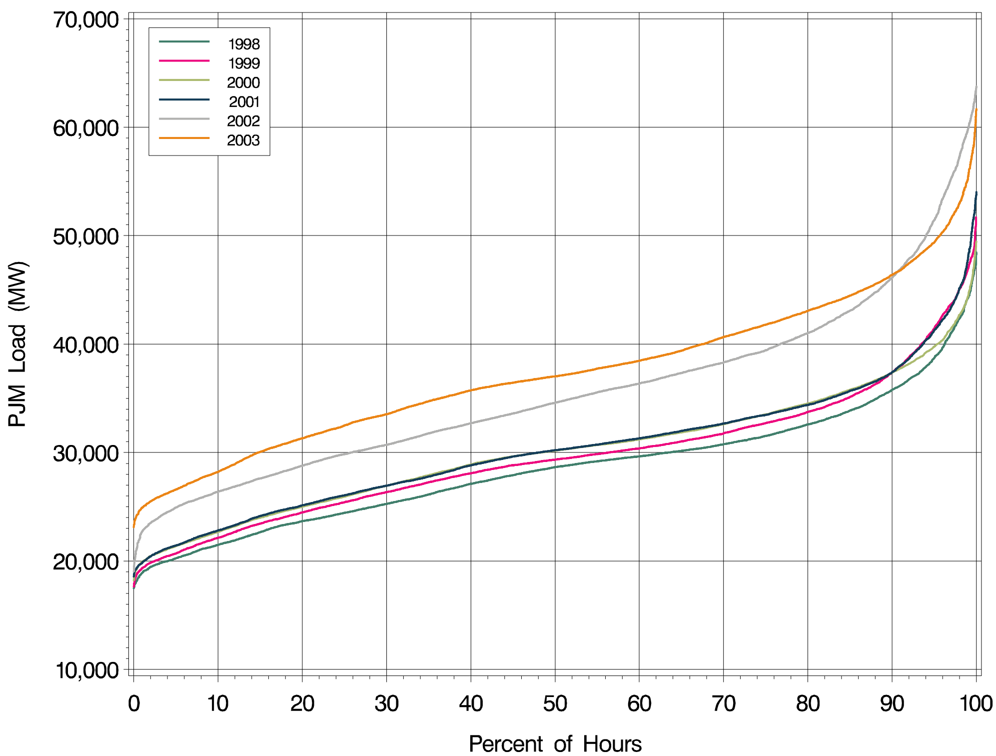
Table 2-24 PJM Load (in MW)

	PJM Load			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average Load	Median Load	Standard Deviation
2003	37,395	37,029	6,834	5.2%	7.0%	-14.0%
2002	35,551	34,596	7,942	17.3%	14.5%	35.2%
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2000	30,113	30,170	5,529	1.6%	2.8%	-7.2%
1999	29,640	29,341	5,956	3.7%	2.4%	8.1%
1998	28,577	28,653	5,512			

Load Duration

Figure 2-29 shows load duration curves for 1998, 1999, 2000, 2001, 2002 and 2003. A load duration curve shows the percent of hours when load was at or below a given level for the year. The 2003 load duration curve reflects the first full year of PJM Western Region load and lies above load duration curves for all years with the exception of the approximately 10 percent of the high-load hours in 2002 which had also included PJM Western Region load as well as higher summer load conditions.

Figure 2-29 PJM Hourly Load Duration Curve: 1998 - 2003



28 The PJM Western Region was added on April 1, 2002. The load comparison for the first quarter of 2003 is for PJM Mid-Atlantic Region load only. The comparison for the last three quarters of the year is for the PJM system. The average for the full year 2003 includes the additional load from the PJM Western Region during the first quarter. The table shows the actual 2002 and actual 2003 loads.

29 See Appendix C, "Energy Market," for additional load frequency details, including on-peak and off-peak loads.

Load-Weighted LMP

Market participants typically purchase more energy during high-priced periods as higher demand results in higher prices. As a result, when hourly load levels are reflected, the 2003 average hourly load-weighted LMP was about 8 percent higher than the simple average LMP.

Load-weighted LMP reflects the average LMP paid for actual MWh generated and consumed during a year. Hourly LMP is weighted by the total MW of load in each hour to derive load-weighted LMP.

As Table 2-25 shows, 2003 load-weighted LMP rose to $41.23 per MWh, 30.5 percent higher than in 2002, 12.5 percent higher than in 2001 and 34.2 percent higher than in 2000.[30]

Table 2-25 PJM Load-Weighted, Average LMP (in Dollars per MWh)

	Load-Weighted Average LMP			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
2003	$41.23	$34.95	$25.40	30.5%	49.3%	-5.0%
2002	$31.60	$23.41	$26.74	-13.8%	-6.7%	-53.3%
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2000	$30.72	$20.51	$28.38	-9.8%	7.8%	-69.0%
1999	$34.06	$19.02	$91.49	41.0%	8.1%	132.9%
1998	$24.16	$17.60	$39.29			

Fuel Cost and Price

Changes in LMP can result from changes in unit costs. Fuel costs comprise the bulk of marginal costs for most generating units. To account for differences in fuel cost between 2002 and 2003, the 2003 load-weighted LMP was adjusted to reflect the change in price of fuels used by the marginal units and the change in marginal MW generated by each fuel type.[31]

Table 2-26 compares 2003 load-weighted, fuel-cost-adjusted, average LMP to 2002 load-weighted, average LMP.[32] After adjustment for fuel price changes, load-weighted, average LMP in 2003 was 9.5 percent lower than in 2002. If fuel prices for both years had been the same, the 2003 load-weighted LMP would have been $28.60 per MWh instead of $41.23 per MWh. This means that, but for the increases in fuel costs, LMP would have been lower in 2003 than in 2002. The fact that higher fuel prices were reflected in higher Energy Market prices is consistent with the functioning of a competitive market.

Table 2-26 PJM Load-Weighted, Fuel-Cost-Adjusted LMP (in Dollars per MWh)

	2003	2002	Percent Change
Average LMP	$28.60	$31.60	-9.5%
Median LMP	$24.40	$23.41	4.2%
Standard Deviation	$16.94	$26.74	-36.6%

30 See Appendix C, "Energy Market," for peak and off-peak load-weighted LMP details.
31 See Appendix C, "Energy Market," for fuel cost adjustment method.
32 Note that the base of the comparison is the simple load-weighted average LMP. This comparison is for these two years only and cannot be extended to multiple years.

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. As the following tables and graphs show, day-ahead prices and real-time prices have converged. Day-ahead prices were higher than real-time prices by $0.45 per MWh on average during 2003. During 2002, day-ahead prices were $0.16 per MWh higher than real-time prices. In 2001, day-ahead prices were $0.37 per MWh higher than real-time prices, and in 2000, day-ahead prices were $1.61 per MWh higher than real-time prices.

Figure 2-30 shows 2003 price duration curves for the two markets, while Figure 2-31 shows 2003 price duration curves for hours above the 95th percentile. The two figures show that real-time and day-ahead prices were almost coincident for the lowest priced 20 percent of the hours and again during the 60 to 80 percent range, with some alteration in the pattern over the course of the hours. Real-time prices were slightly higher for the remaining 20 percent of the hours while the difference increased in the highest priced 1 percent of the hours.

Figure 2-30 PJM Price Duration Curves -- Real-Time and Day-Ahead Energy Markets: 2003

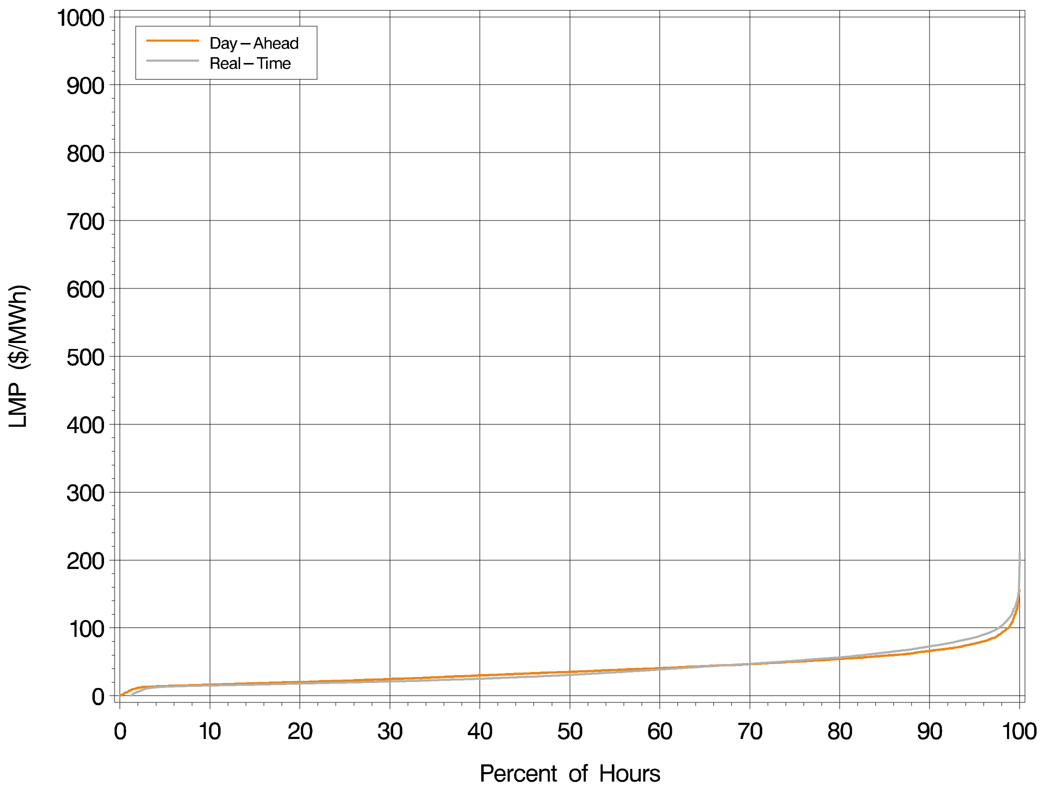


Figure 2-31 PJM Price Duration Curves -- Real-Time and Day-Ahead Energy Markets – Hours above the 95th Percentile: 2003

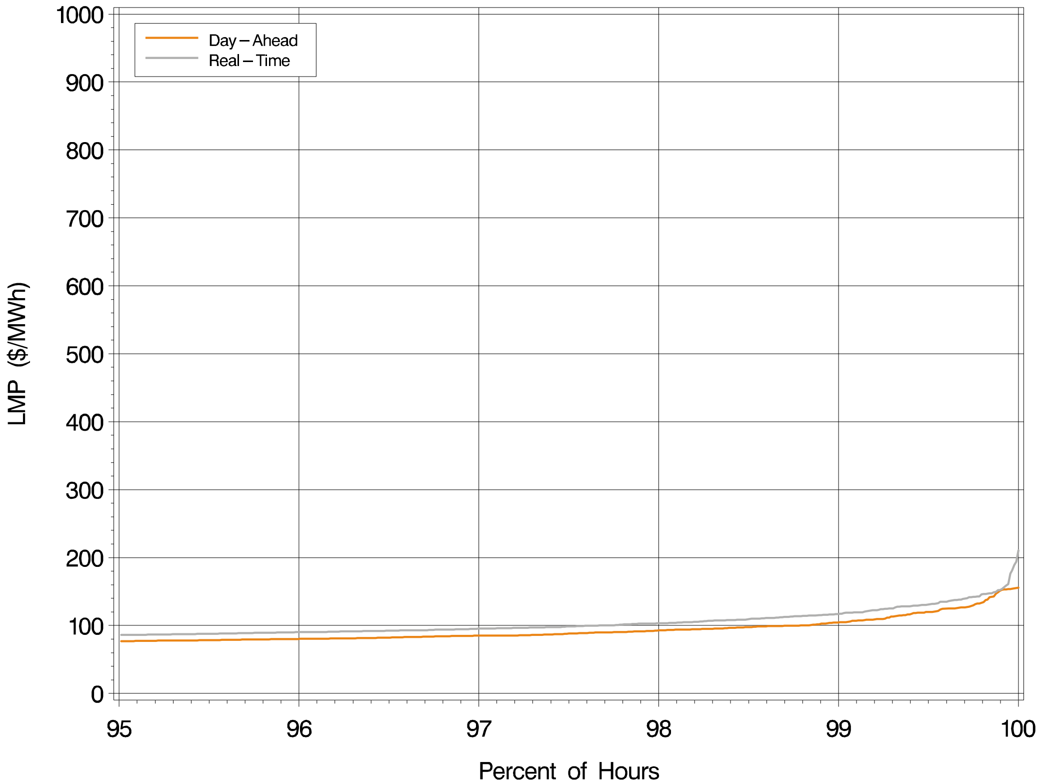


Figure 2-32 compares average hourly day-ahead and real-time LMP for 2003. Although the average difference between the Day-Ahead and Real-Time Markets was only $0.45 per MWh for the entire year, Figure 2-32 shows considerable variation, both positive and negative, between day-ahead and real-time prices, especially during the first quarter of the year. Figure 2-33 shows the average hourly levels of real-time and day-ahead LMP.[33]

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

Figure 2-32 Hourly Real-Time LMP minus Day-Ahead LMP: 2003

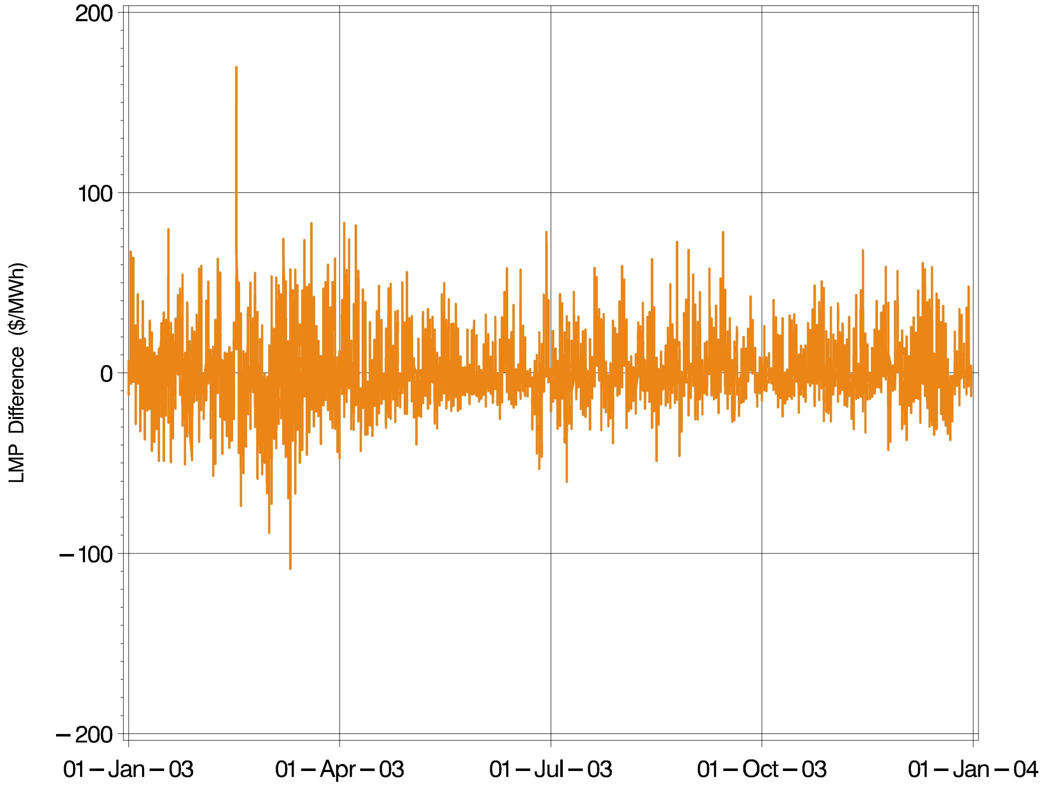


Figure 2-33 PJM Average Hourly System LMP

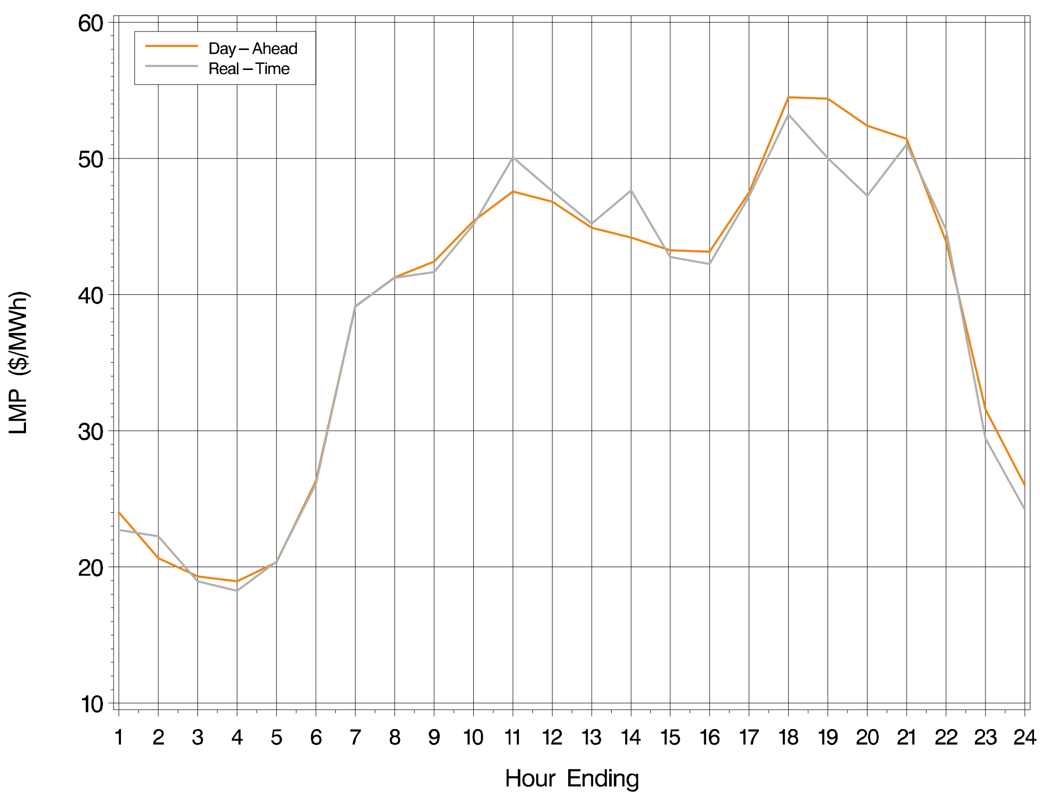


Table 2-27 presents summary statistics for the two markets. Average LMP in the Day-Ahead Energy Market was $0.45 per MWh or 1.2 percent higher than average LMP in the Real-Time Energy Market. The day-ahead median LMP was 14.4 percent higher than real-time LMP, reflecting an average difference of $4.43 per MWh. Consistent with the price duration curve, price dispersion in the Real-Time Energy Market was 15.7 percent greater than in the Day-Ahead Energy Market, with an average difference in standard deviation between the two markets of $3.87 per MWh.[34]

Table 2-27 Comparison of Real-Time and Day-Ahead 2003 Market LMP (in Dollars per MWh)

	Day-Ahead	Real-Time	Difference	Difference as Percent Real-Time
Average LMP	$38.72	$38.27	-$0.45	-1.2%
Median LMP	$35.21	$30.79	-$4.43	-14.4%
Standard Deviation	$20.84	$24.71	$3.87	15.7%

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[35], three types of financially binding commitments for generation are made and cleared:

- **Self-Scheduled.** Units 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.
- **Generator Offers.** Schedules of MW offered and the corresponding offer price.
- **Increment Offers.** Financial offers to supply specified amounts of MW at or above a given price.

Figure 2-34 shows average hourly values of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2003. Day-ahead generation is all generator offers cleared in the Day-Ahead Energy Market. During 2003, 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 would have always exceeded real-time generation.

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

35 All referencees to day-ahead generation and increment offers in the "Day-Ahead and Real-Time Generation" portion of the "Energy Market" section of this report are presented in cleared MW amounts.

Figure 2-34 2003 Average Hourly Values for Real-Time and Day-Ahead Generation

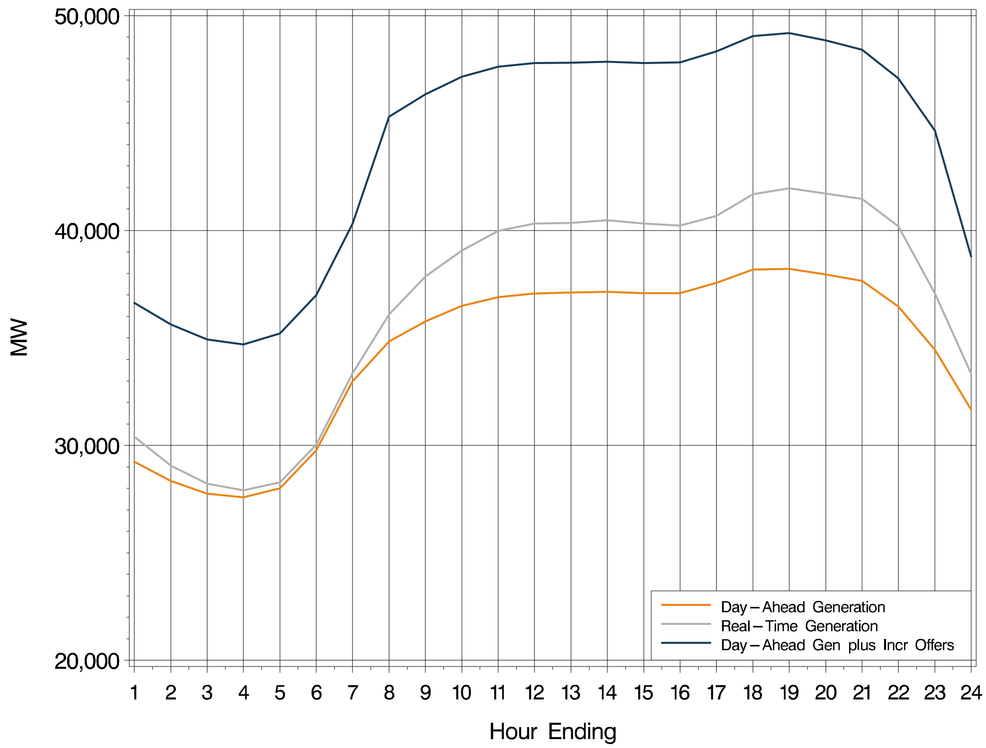


Table 2-28 presents summary statistics for 2003 day-ahead and real-time generation and the average differences between them. Day-ahead generation averaged 2,282 MW less than real-time generation. The sum of day-ahead generation offers and increment offers was 7,255 MW higher than real-time generation.

Table 2-28 2003 Day-Ahead and Real-Time Generation (in MW)

	Day-Ahead		Real-Time	Average Difference	
	Generation	Increment Offers	Generation	Generation	Generation plus Increment Offers
Average MW	34,389	9,537	36,672	-2,282	7,255
Median MW	34,297	9,007	36,580	-2,283	6,723
Standard Deviation	5,938	2,565	7,485	-1,547	1,018

Table 2-29 demonstrates that during 2003 differences between the sum of the two types of day-ahead generation offers and real-time generation were greatest during peak hours.

Table 2-29 shows the average MW offer values in the PJM Day-Ahead and Real-Time Markets during the off-peak and on-peak hours, while Table 2-30 shows the average differences between day-ahead generation and increment offers and real-time generation during both the off-peak and on-peak hours. Day-ahead generation was less than real-time generation in both periods. The average difference between day-ahead and real-time generation during off-peak hours was 1,216 MW, and the average difference during peak hours was 3,505 MW. The sum of day-ahead generation and increment offers exceeded real-time generation during both periods. During off-peak hours, day-ahead generation plus increment offers averaged 6,361 MW more than real-time generation; and during peak hours, day-ahead generation plus increment offers averaged 8,280 MW more than real-time generation.

Table 2-29 2003 Day-Ahead and Real-Time On-Peak and Off-Peak Generation (in MW)

	Day-Ahead				Real-Time	
	Off-Peak Generation	On-Peak Generation	Off-Peak Increment Offers	On-Peak Increment Offers	Off-Peak Generation	On-Peak Generation
Average MW	31,220	38,024	7,578	11,785	32,436	41,529
Median MW	30,816	37,017	7,589	11,607	31,755	40,214
Standard Deviation	5,029	4,688	1,080	1,826	6,166	5,702

Table 2-30 Average 2003 Differences between Day-Ahead and Real-Time Markets (in MW)

	Off-Peak		On-Peak	
	Generation	Generation Plus Increment Offers	Generation	Generation Plus Increment Offers
Average MW Difference	-1,216	6,361	-3,505	8,280
Median MW Difference	-939	6,650	-3,197	8,410

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 Bids.** Bids to purchase a defined MW level of energy, regardless of LMP.
- **Price-Sensitive Bids.** Bids to purchase a defined MW level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bids.** Financial bids to purchases a defined MW level of energy up to a specified LMP, above which the bid is zero. Decrement bids are financial bids that can be submitted by any market participant.

Figure 2-35 shows the average 2003 hourly values of day-ahead load, fixed-demand, price-sensitive load, decrement bids and total day-ahead and real-time load (total day-ahead load is the sum of the three demand components).

Figure 2-35 2003 Average Hourly Values for Real-Time and Day-Ahead Loads

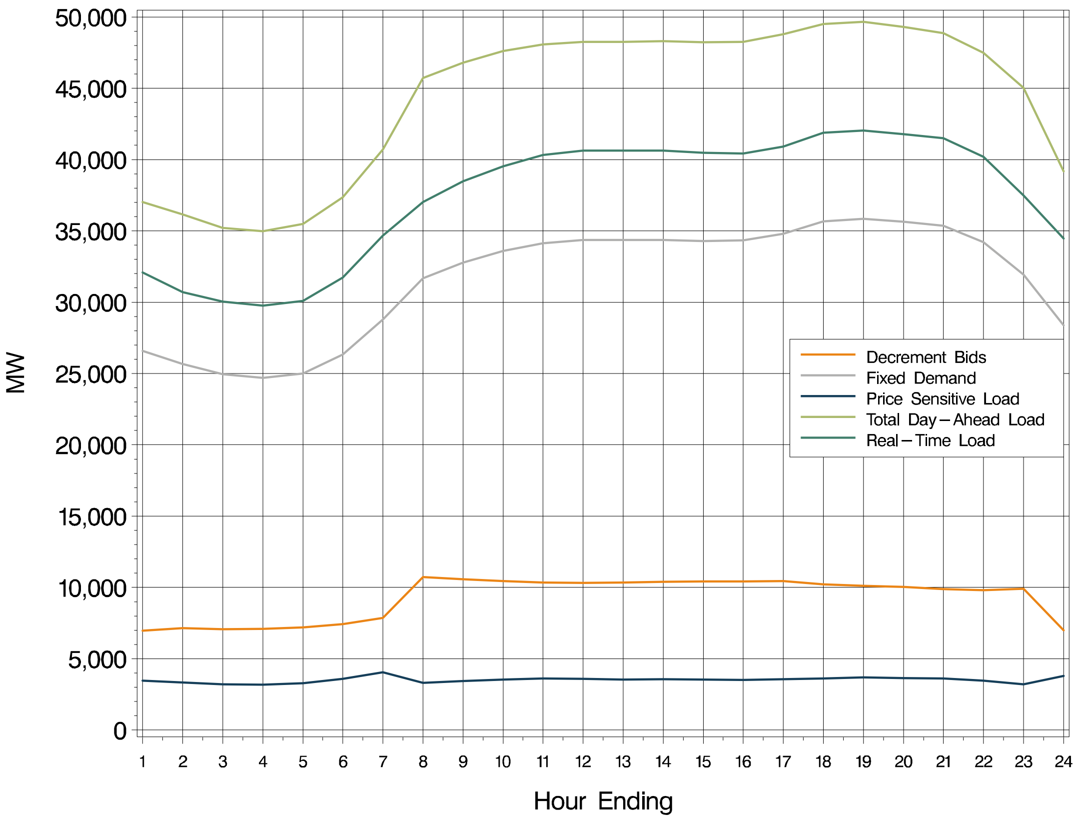


Table 2-31 presents summary statistics for 2003 day-ahead load components, total day-ahead load, real-time load and the average difference between total day-ahead load and total real-time load.

As Figure 2-35 and Table 2-31 show, during 2003 total day-ahead load was higher than real-time load by an average of 6,947 MW. The table also shows that, at 71 percent, fixed demand was the largest component of day-ahead load. At 8 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 21 percent of day-ahead load.

Table 2-31 2003 Day-Ahead and Real-Time Load (in MW)

	Day-Ahead				Real-Time	
	Fixed Demand	Price Sensitive	Decrement Bids	Total Load	Total Load	Average Difference
Average MW	31,569	3,517	9,253	44,340	37,393	6,947
Median MW	31,606	3,511	9,101	44,368	37,028	7,340
Standard Deviation	6,002	871	2,173	7,883	6,835	1,048

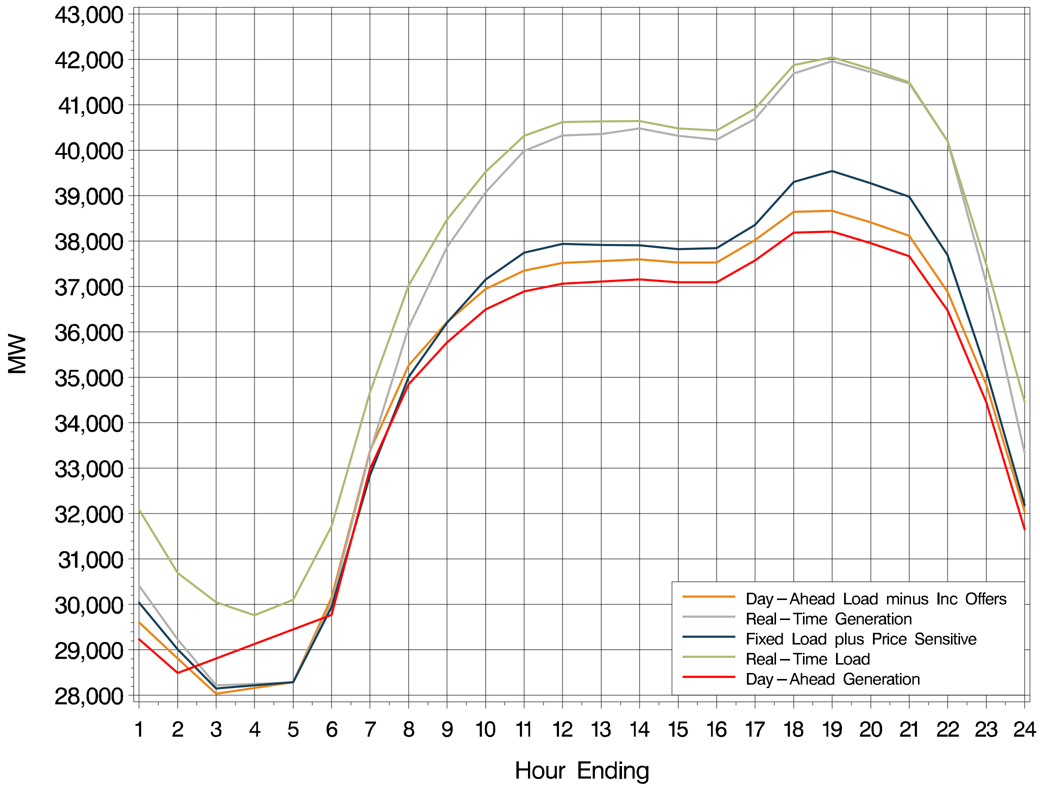
As Figure 2-35 shows, except for price-sensitive demand, day-ahead load components increased during on-peak hours as did real-time load. Table 2-32 shows the average load MW values in the Day-Ahead and Real-Time Markets for 2003 during the off-peak and on-peak hours. During 2003, real-time load was always higher than fixed-demand load plus price-sensitive load in the Day-Ahead Market. If, however, decrement bids were included, then the day-ahead load would have always exceeded real-time load and total day-ahead load would have been higher than real-time load during both off-peak and on-peak hours. The average difference during off-peak hours was 5,592 MW, while the average difference during on-peak hours was 8,502 MW. The percentage of day-ahead load comprised by each of the components was similar during the two periods. At 71 percent, fixed demand accounted for the largest percentage of day-ahead load during both the off-peak and on-peak periods. Price-sensitive load, at 9 and 7 percent, respectively, accounted for the smallest percentage during both periods while decrement bids accounted for 20 percent and 22 percent, respectively.

Table 2-32 2003 Day-Ahead and Real-Time Load During On-Peak and Off-Peak Hours (in MW)

	Day-Ahead								Real-Time	
	Off-Peak				On-Peak				Off-Peak	On-Peak
	Fixed Demand	Price Sensitive	Dec Bids	Total Load	Fixed Demand	Price Sensitive	Dec Bids	Total Load	Total Load	Total Load
Average	27,799	3,688	7,697	39,183	35,896	3,322	11,039	50,257	33,591	41,755
Median	27,264	3,670	7,581	38,866	35,044	3,358	10,972	48,673	32,970	40,802
Standard Deviation	4,473	838	1,323	5,441	4,401	867	1,471	5,826	5,547	5,424

Figure 2-36 shows day-ahead and real-time load and generation for 2003. For this analysis, increment offers were subtracted from total day-ahead load. Since increment offers look like generation, their subtraction from day-ahead load provides an estimate of day-ahead generation that would have had to be turned on to meet the load.

Figure 2-36 2003 Real-Time and Day-Ahead Load and Generation: Average Hourly Values



Impact of August 2003 Power Disturbance on LMP

A major electricity outage occurred on August 14, 2003, a few minutes after 4 p.m. EDT in large areas in the Northeast and Midwest United States as well as in Canada. It has been estimated that 50 million people were affected.

PJM was serving approximately 61,200 MW of load at the time of the disturbance. PJM experienced a sustained loss of load of approximately 4,500 MW. About 4,100 MW of the load loss occurred in northeastern New Jersey with the remaining 400 MW of load loss occurring in northwestern Pennsylvania. In addition, 56 generating units tripped off line as a result of the disturbance.

During this time period, however, the PJM Energy Market remained competitive, and there was no discernable impact on LMP during or after the event. Bidding also remained competitive.

Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale energy markets is severely underdeveloped. This underdevelopment is one of the basic reasons for maintaining an offer cap in PJM and in other wholesale power markets. It is widely recognized that wholesale energy markets will work better when a significant level of potential demand-side response is available in the market. The PJM demand-side programs should be understood as one part of a transition mechanism to a fully functional demand side of its Energy Market.

A functional demand side of the energy market does not mean that all customers will curtail usage at specified levels of price. A fully functional demand side of the energy market does mean that all or most customers, or their designated proxies, will have the ability to see real-time prices, 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 usage. If these conditions are met, customers can decide for themselves the relationship between the value and price of power for 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 have the capabilities required to 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.

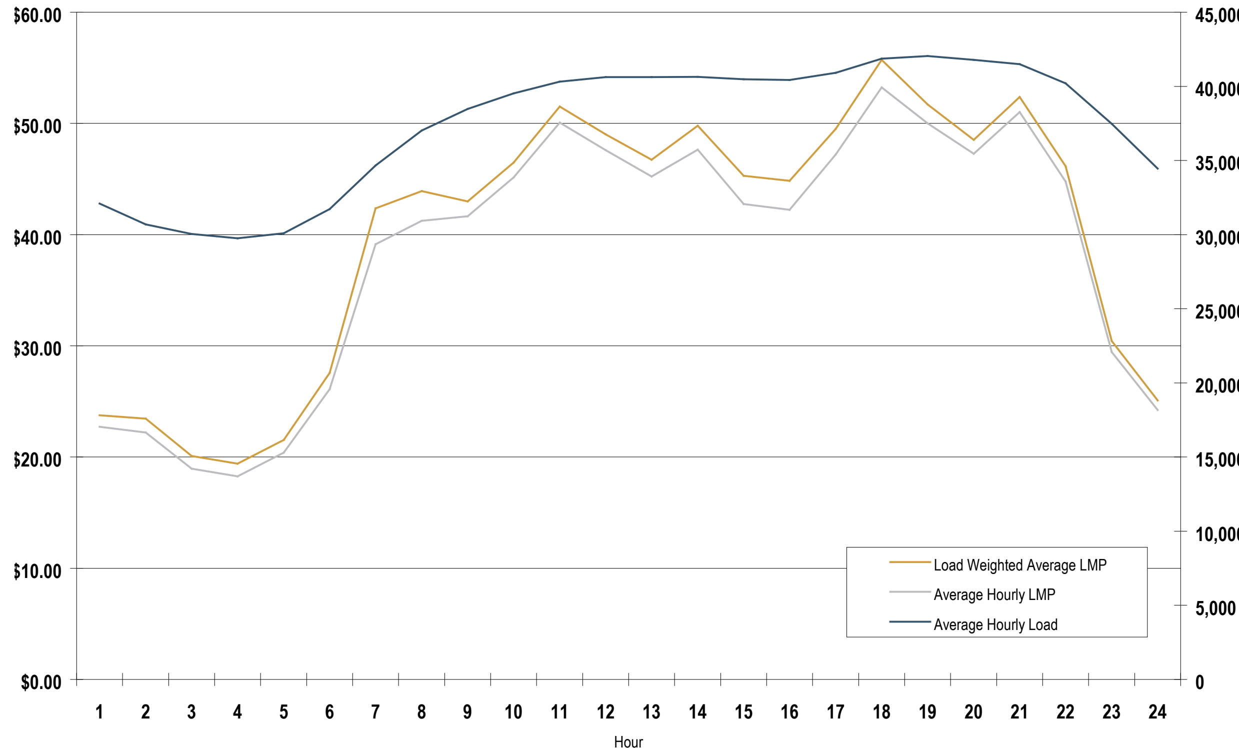
A functional demand side of wholesale energy markets does not necessarily mean that prices will be lower than they otherwise would be. A functional demand side of these markets does mean that customers will have the ability to make decisions about levels of power consumption based both on the value of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

A functional demand side of the wholesale energy market will also tend to induce more competitive behavior among suppliers and to limit the ability to exercise market power. If customers have the essential tools to respond to prices, then suppliers will have the incentive to deliver power on a cost-effective basis, consistent with customers' evaluations.

The PJM Economic Load-Response Program provides a PJM-managed accounting mechanism that requires 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 to transition to a structure where customers do not require mandated payments, but where they either see and react to market signals or enter into contracts with intermediaries to provide that service. Even as currently structured, the Economic Program represents a minimal and relatively efficient intervention into the markets.

The pattern of prices within days and across months illustrates that prices are directly related to demand. The fact that price is a direct function of load (Figure 2-37) illustrates the potential significance of price elasticity of demand in affecting price. The potential for load to respond to changes in price is a critical component of a competitive market which remains as yet undeveloped in the wholesale energy market.

Figure 2-37 PJM Average Hourly LMP and System Load: 2003



On February 14, 2002, the PJM Members Committee (MC) approved a permanent Emergency Load-Response Program. On March 1, 2002, PJM filed amendments to the PJM Open Access Transmission Tariff (PJM Tariff) and to the Amended and Restated Operating Agreement (PJM Operating Agreement) to establish a permanent Emergency Load-Response Program (Emergency Program). By order dated April 30, 2002, the FERC approved the Emergency Program effective June 1, 2002, but set a sunset date for it of December 1, 2004.

Similarly, on March 15, 2002, PJM submitted filing amendments to the PJM Tariff and PJM Operating Agreement to establish a multiyear Economic Load-Response Program (Economic Program). On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002. Like the Emergency Program, the Economic Program is effective until December 1, 2004.

Emergency Program

There was only one emergency event during the summer of 2003 (August 15), and this event was a locational emergency. On this day, a total of 47 MWh were reduced over an 11-hour period. The maximum hourly reduction in the Emergency Program was 6 MW.

Economic Program

As measured by total MW enrolled in the program and actual MWh response under it, the Economic Program has grown significantly in the two years since its 2001 inception. In 2003, there were a total of 724 MW registered in the Economic Program, an increase of 115 percent from 337 MW in 2002 which was, in turn, an increase of about 400 percent over the 65 MW enrolled in 2001. The level of load reductions in the Economic Program increased from 50 MWh in 2001 to 6,462 MWh in 2002 to 14,678 MWh in 2003.[35] Consistent with lower LMPs, payments per MWh have decreased 58 percent from 2001 to 2002, and decreased 61 percent from 2002 to 2003. The MWh of actual load reductions per MW enrolled in the Economic Program increased from 2001 to 2002 and was relatively constant between 2002 and 2003.

35 Load reductions are measured by multiplying hourly MW reductions by the hours in which they occur. 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 is 4 MWh.

During the summer of 2003, load levels were somewhat lower than during the summer of 2002, and the combination of milder weather plus changes in supply and demand conditions resulted in lower prices. Using actual demand reductions and real-time supply curves, the MMU estimated that the price impact of the Economic Program was approximately $1 per MWh in 2003.

The maximum hourly load reduction attributable to the Economic Program was about 82 MW in 2003. Based on the real-time supply curves for a representative day during the summer of 2003 and the summer peak load, a reduction of 1,000 MW would have resulted in a $10 reduction in LMP and a reduction of 2,000 MW would have resulted in a $15 reduction in LMP. LMPs were lower during the summer of 2003 based on supply-demand fundamentals, and the potential price impacts of load reductions were also attenuated by supply-demand fundamentals. This is demonstrated by the aggregate supply curve for the summer of 2003 (Figure 2-37).

Non-hourly Metered Program

PJM created the non-hourly metered program as part of an effort to extend participation in the demand side of the market to smaller customers that generally lack hourly meters. PJM's non-hourly metered program serves as a pilot program for such customers, if they or their representatives propose an alternate method for measuring load reduction. Such measurement methods are approved by PJM on a case by case basis, and participants are otherwise subject to the rules and procedures governing the load-response program in which the customer has enrolled.

To provide sufficient opportunities to all non-hourly metered customers, PJM suggested an increase in the 25 MW limit. At its April 16, 2003, meeting the PJM Energy Market Committee supported an increase in the aggregate MW limit, expanding it to 100 MW. PJM's Members Committee approved the change at its May 1, 2003, meeting endorsing the revisions to the PJM Open Access Transmission Tariff. These changes were accepted by the FERC on June 27, 2003.[36]

In 2003, one customer (with about 45,000 retail customers) participated in the non-hourly metered program for about 131 separate hourly reductions, totaling about 1,816 MWh and averaging about 14 MW per hour. The expansion of the aggregate MW limit allowed for a maximum hourly reduction of 43 MW in the non-hourly metered program.

Customer Demand-Side Response Programs

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 phenomena. To address this issue, in July 2003 PJM conducted a survey of LSEs 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 July 2003 PJM survey revealed that there is substantial load in PJM that is exposed to real-time prices because of actions by state public utility commissions. In addition, LSEs in the PJM footprint operate their own DSR programs that are completely independent of those operated by PJM.

The survey results identified 3,122 MW of load that pays real-time prices. These retail customers pay real-time prices as the result of tariffs approved by state public utility commissions in New Jersey and Maryland. Of the 3,122 MW of load, 1,978 MW or about 63 percent of the total, currently purchases electricity directly at an hourly LMP rate plus an adder. This load has chosen to pay LMP rates rather than to enter into a contract with a competitive supplier. The remaining 1,144 MW or 37 percent represents retail customers who have shifted the risk of managing real-time price volatility to a competitive supplier.

36 103 FERC 61,365 (June 27, 2003).

The survey also identified a total of about 500 MW enrolled in independent DSR programs. Of the total, 193 MW or 39 percent were included in price-responsive load programs or pilot programs, 73 MW or 15 percent participated in interruptible load programs and 235 MW or 47 percent of load is currently participating in emergency load-response programs of electric distribution companies.

The July 2003 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 directly exposed to real-time prices. 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.

DSR Program Summary Data

Summary data for Demand-Side Response programs in the PJM service area are presented in Table 2-33. The programs include the PJM Emergency Load-Response Program, the PJM Economic Load-Response Program, the PJM Active Load Management Program (ALM) net of ALM resources participating directly in other PJM demand-side programs and additional programs reported by PJM customers in response to a survey.[37]

Table 2-33 2003 Demand-Side Response Program

PJM Programs	MW Registered
PJM Economic Load-Response Program	724
PJM Emergency Load-Response Program	659
PJM Active Load-Management Resources	1,207
PJM ALM Resources Included in Load-Response Program	(445)
Total PJM Programs	2,145
Additional Programs Reported By Customers in PJM Survey	
Direct Customer Purchases Based on LMP Signals	1,978
Competitive Contracts in NJ and MD	1,144
Independent	
Price-Responsive Load or Pilot Programs	193
Interruptible Load Programs	73
Emergency Load-Response Programs of EDCs	235
Total Independent	501
Total Additional Programs	3,623
Partial Summer Load Participation	(850)
Net Load, Including Survey Responses	**4,918**

37 The table reflects the fact that the survey includes 850 MW associated with retail customers that left their DSR program in mid-summer. The "partial summer load reduction" row of the table reflects that this was subtracted from relevant participation as it was not present for the entire summer of 2003. After accounting for this reduction, there was a total of 4,918 MW of demand-side resources in the PJM service area in the summer of 2003.

Section 3 – Interchange Transactions

PJM has interfaces with four contiguous, external regions. These interfaces are the seams between PJM and other regions. PJM market participants import energy from, and export energy to, external regions on a continuous basis.[1] These transactions may fulfill long-term or short-term bilateral contracts or take advantage of price differentials.

At the end of 2003, PJM's four interfaces had five interface pricing points: PJM/New York Independent System Operator (PJM/NYIS), PJM/FirstEnergy Corp. (PJM/FE), PJM/Duquesne Light Company (PJM/DLCO), PJM/AEPVP, and PJM/Ontario Independent Electricity Market Operator (PJM/IMO). The first three were in place at the beginning of the year; the last two were created in 2003 to help manage loop flow issues. In March, PJM/AEPVP was formed by combining the PJM/American Electric Power Company, Inc. (PJM/AEP) and PJM/Virginia Electric and Power Company (PJM/VAP) interfaces. On August 1, 2003, PJM/IMO was created.

Overview

Transaction Activity

- **Aggregate Imports and Exports.** For each month of 2003, PJM was a net importer of power, averaging 1.15 million MWh of net imports per month, or slightly less than the year 2002 level of 1.23 million MWh. The 2003 average monthly gross import volume of 2.60 million MWh also represented a slight decline from 2.67 million MWh in 2002. Gross exports changed little in 2003 from 2002, averaging 1.45 million MWh in 2003 and 1.44 million MWh in 2002.

- **Interface Imports and Exports.** During 2003, net imports at two interfaces accounted for 96 percent of total net imports. Net imports at the PJM/AEPVP interface were 49 percent and net imports at the PJM/FE interface were 47 percent. Net exports occurred only at the PJM/NYIS interface.

Interchange Transaction Issues

- **Loop Flow.** Loop flow results when the transmission contract path for energy transactions does not match the actual path of energy flows on the transmission system. Loop flows can arise from transactions scheduled into, out of or around the PJM system. Outside of PJM's LMP-based Energy Market, energy is scheduled and paid for based on contract path while the actual associated energy deliveries flow on the path of least resistance. Loop flows can result when a transaction is scheduled between two external control areas and some or all of the actual flows occur at PJM interfaces. Loop flows can also result when transactions are scheduled into or out of PJM on one interface, but actually flow on another. Although total PJM scheduled and actual flows were approximately equal in 2003, such was not the case for each individual interface.

- **Interface Pricing Issues.** PJM experienced continuing loop flow issues during the winter of 2002 and early in 2003 when transactions scheduled for delivery at the PJM/VAP interface actually flowed at the PJM/AEP interface. When the issue first emerged in the summer of 2002, it resulted from actions designed to exploit differences between the way in which PJM locational marginal prices (LMPs) were determined and the artificial contract paths that existed west and south of PJM. To address that problem, PJM issued updated rules in July 2002. Ongoing investigation into loop flows and circulation impacting PJM indicated, however, that further modifications were needed to the pricing rules governing external transactions. Specifically, a continuing discrepancy between scheduled and actual power flows at the PJM/AEP and the PJM/VAP interfaces worsened, particularly during the off-peak hours, late in 2002 and continued into early 2003 despite the July 2002 rule changes.[2] To address this issue, on February 24, 2003, the PJM Market Monitoring Unit

1 These transactions occur primarily in the Real-Time Energy Market. Approximately 82 percent of total gross imports and 84 percent of gross exports take place in the Real-Time Energy Market without corresponding day-ahead transactions.

2 The July 2002 rule changes had mitigated the magnitude of the recurrence.

(MMU) notified market participants of a rule change governing interface pricing for transactions, scheduled to and from specific control areas. The PJM/AEP and PJM/VAP interfaces were combined into a new, single, PJM/AEPVP interface. The document, "Mapping for External Transaction Pricing," was developed; it assigned specific control areas an import and export price point regardless of contract path.[3] Additionally, on August 1, 2003, PJM created the PJM/IMO interface pricing point that is applicable to transactions sourcing/sinking into IMO. This price point was added to address the fact that flows from IMO flow over both the PJM/NYIS and PJM Western Interfaces and, therefore, that neither price was appropriate for such transactions.

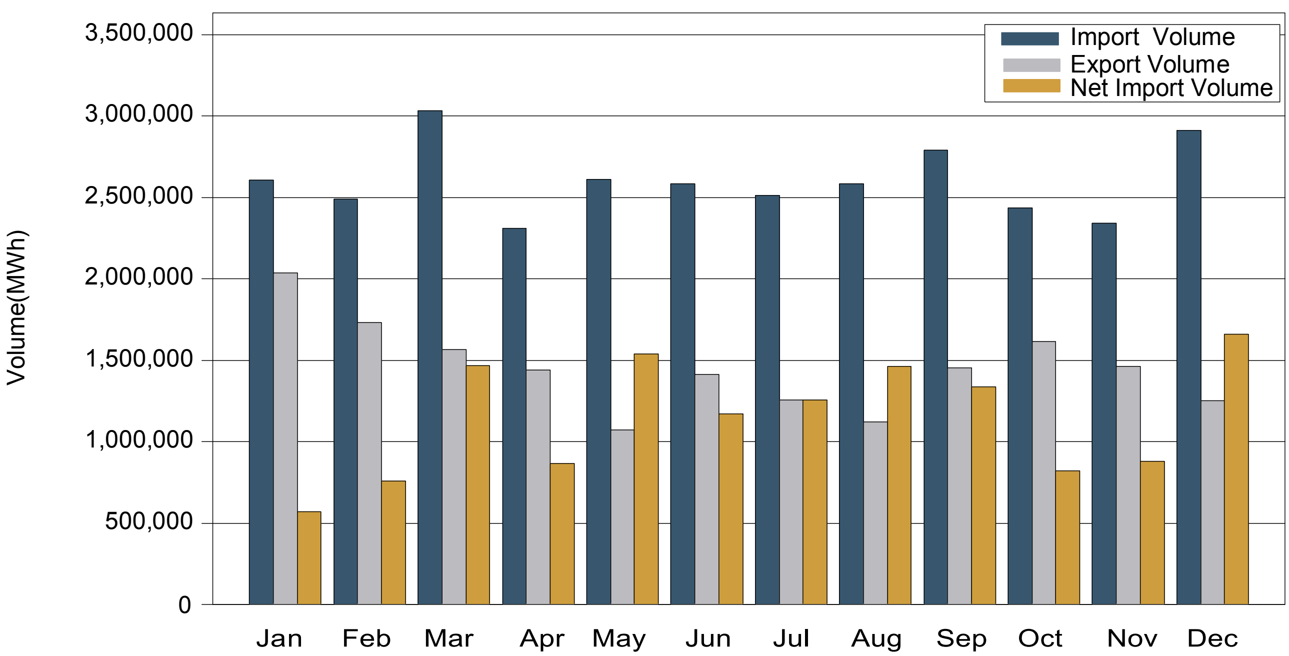
- **PJM and New York Transaction Issues.** The relationship between the PJM/NYIS interface price and the New York Independent System Operator (NYISO) PJM Proxy bus price appears to reflect economic fundamentals. The relationship between interface price differentials and power flows between PJM and the NYISO also appears to reflect economic fundamentals. However, both are affected by differences in institutional and operating practices in PJM and NYISO.

Transaction Activity

Aggregate Imports and Exports

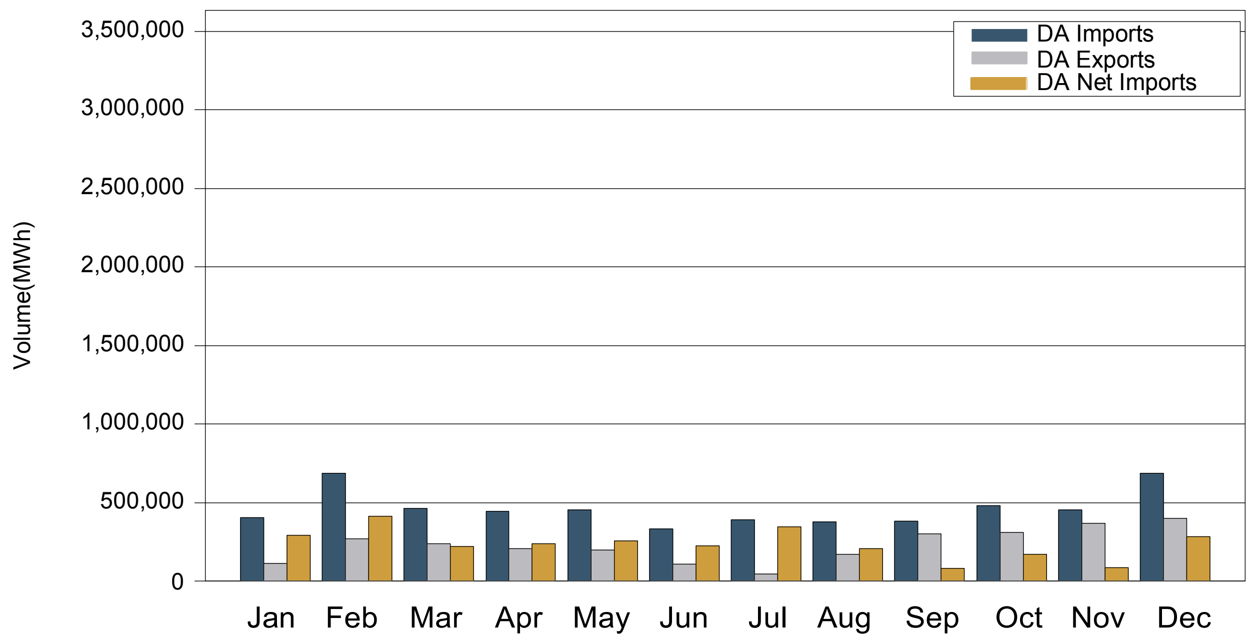
PJM was a net importer of energy for each month of 2003, although monthly net imports did not reach the levels experienced during January, March, May and June 2002 when each month had net import volume in excess of 1.9 million MWh. The 2003 peak net import was 1.7 million MWh in December with all other months at or below 1.5 million MWh (Figure 3-1). Monthly net import volume in 2003 was more consistent than in 2002 (Figure 3-3). The standard deviation of monthly net import flows was 358,000 MWh in 2003 compared to 683,000 MWh in 2002. PJM market participants import and export energy primarily in the Real-Time Energy Market (Figure 3-1 and Figure 3-2). In 2003, approximately 82 percent of total gross imports (85 percent in 2002) and 84 percent of total gross exports (93 percent in 2002) took place in the Real-Time Energy Market without corresponding day-ahead imports and exports.

Figure 3-1 PJM Real-Time Imports and Exports: 2003



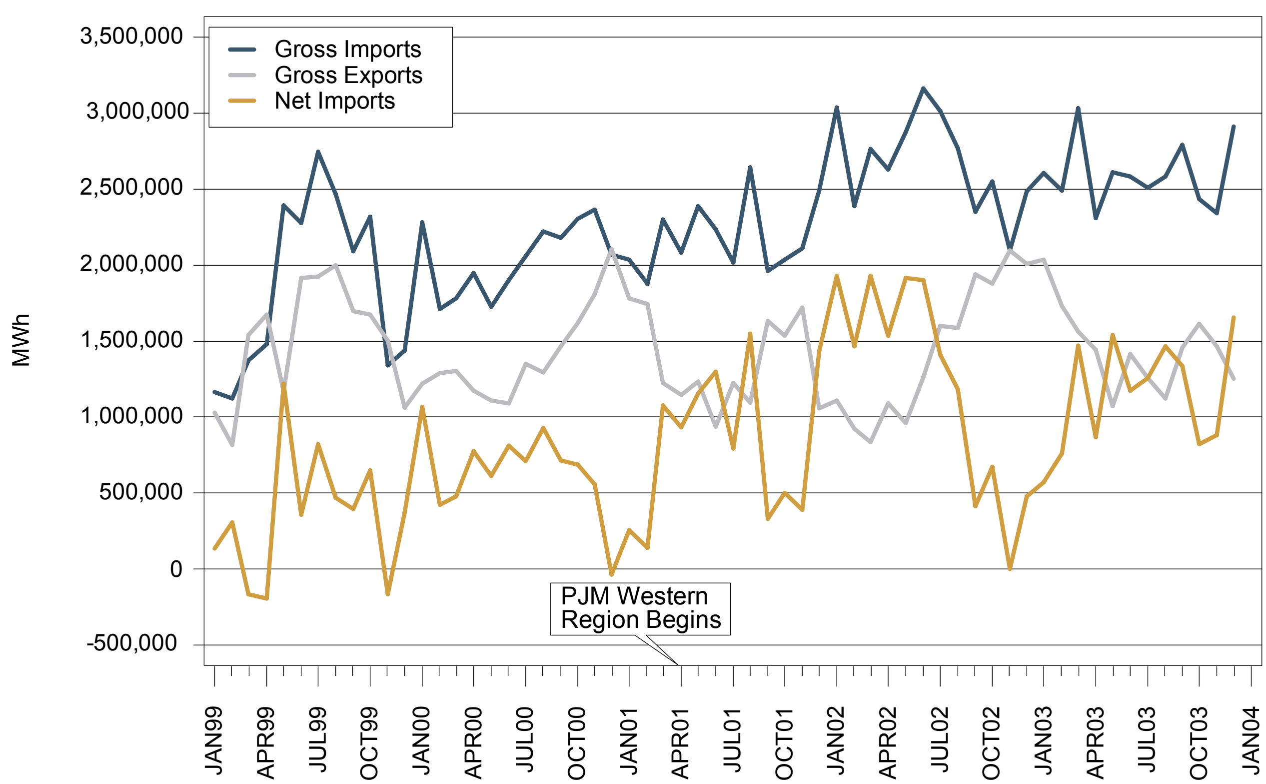
3 The language is from the current rule which was updated most recently on February 24, 2003.

Figure 3-2 Total Day-Ahead Import and Export Volume: 2003



Gross imports and exports have continued to show different patterns. Gross imports have been increasing since 1999, although the rate of increase fell in 2003 when only two months exceeded the long-term trend (Figure 3-3). Gross exports continued to be relatively flat in 2003 with about an equal number of months above and below long-term trends (Figure 3-3).

Figure 3-3 PJM Imports and Exports: Transaction Volume History

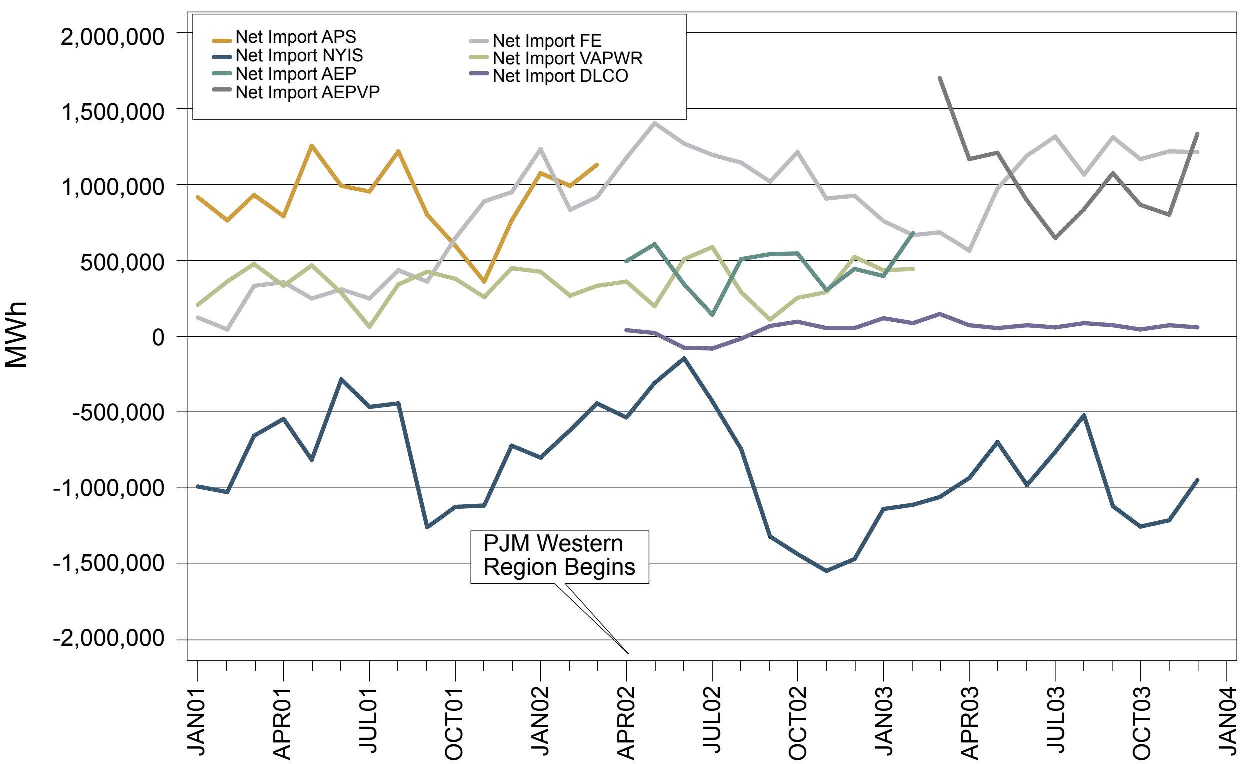


Interface Imports and Exports

Total imports and exports are comprised of flows at each of the four interfaces. Net imports by interface are shown in Figure 3-4 at interfaces before and after the addition of the PJM Western Region and the transformation of the PJM/AEP and PJM/VAP interfaces into the single PJM/AEPVP interface. The bulk of PJM's net imports occur at the PJM/FE and PJM/AEPVP interfaces. Large volumes of net exports occur regularly only at the PJM/NYIS interface. In 2003, the PJM/AEPVP and PJM/FE interfaces accounted for approximately 96 percent of total net imports, 49 and 47 percent, respectively. The PJM/NYIS interface carried all of the net export volume. Relatively low net import volume at PJM/FE early in 2003 continued a downward trend that had started in mid-2002, but then reversed in mid-2003. Higher net exports at PJM/NYIS (11.7 million MWh in 2003 versus 9.8 million MWh in 2002) contributed to the 7 percent decrease in system net imports during 2003 (13.8 million MWh) when compared to 2002 (14.8 million MWh).

Combining the PJM/AEP and PJM/VAP interfaces, PJM made the PJM/AEPVP the largest net import interface in 2003. Net imports there exceeded net imports at PJM/FE by 2 percent. Net exports to PJM/NYIS exhibited a much less variable pattern (a monthly volume standard deviation of 221,000 MWh in 2003 versus 497,000 MWh in 2002) and higher annual total volume than during 2002. Net imports from PJM/DLCO continued to exhibit about the same total volume in 2003 as they had in 2002.

Figure 3-4 Interface Net Imports: January 1, 2001, through December 31, 2003



The individual interface gross import and export volumes are presented in Figure 3-5 and Figure 3-6. The highest levels of gross imports occurred on the PJM/AEPVP interface (46 percent) and the PJM/FE interface (44 percent). The PJM/DLCO and PJM/NYIS interfaces have had the lowest gross import volumes. Gross exports occurred primarily at the PJM/NYIS tie. Approximately 77 percent of the gross exports occurred at the PJM/NYIS interface while PJM/AEPVP, PJM/FE and PJM/DLCO carried 11, 8 and 4 percent, respectively. The monthly average gross export volume at the PJM/NYIS interface over the past three years has been 1,034,217 MWh while the monthly average gross export volume for all the other tie lines together has been 383,219 MWh.

Figure 3-5 Interface Gross Imports: January 1, 2001, through December 31, 2003

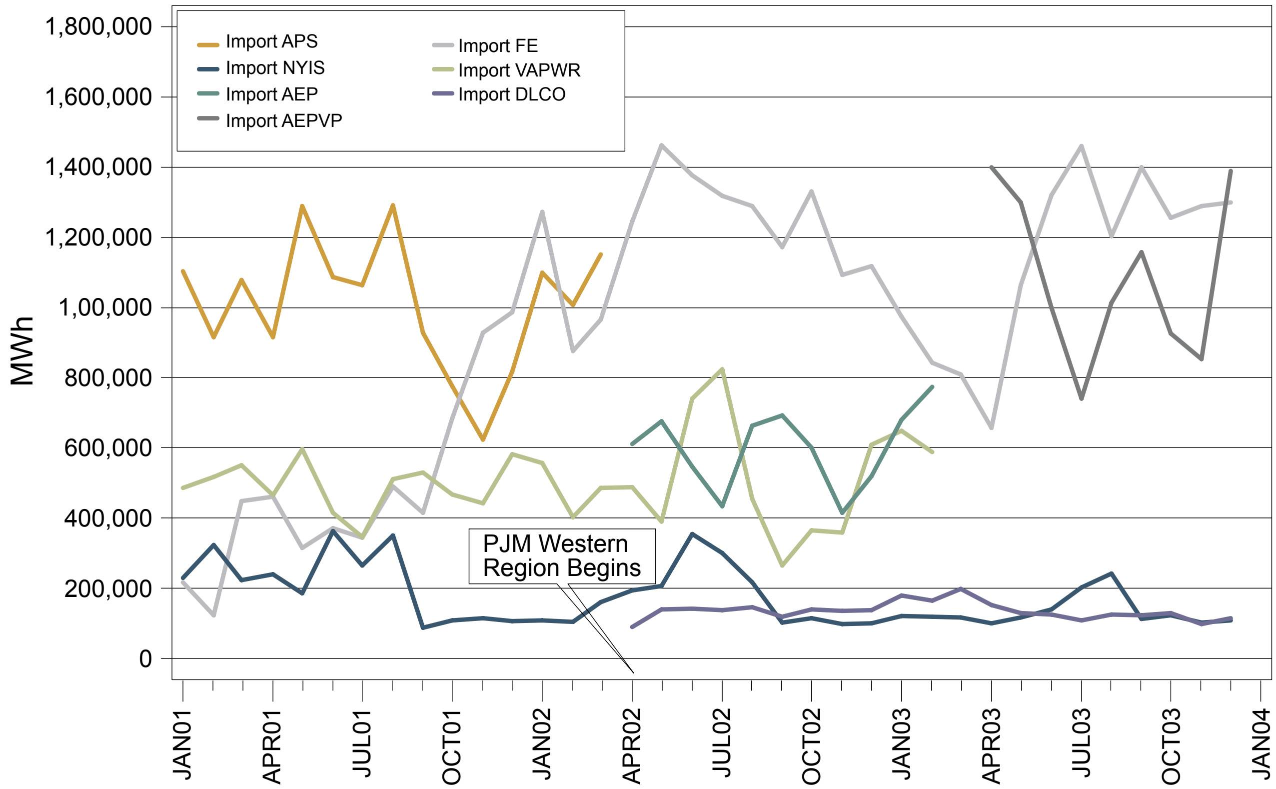
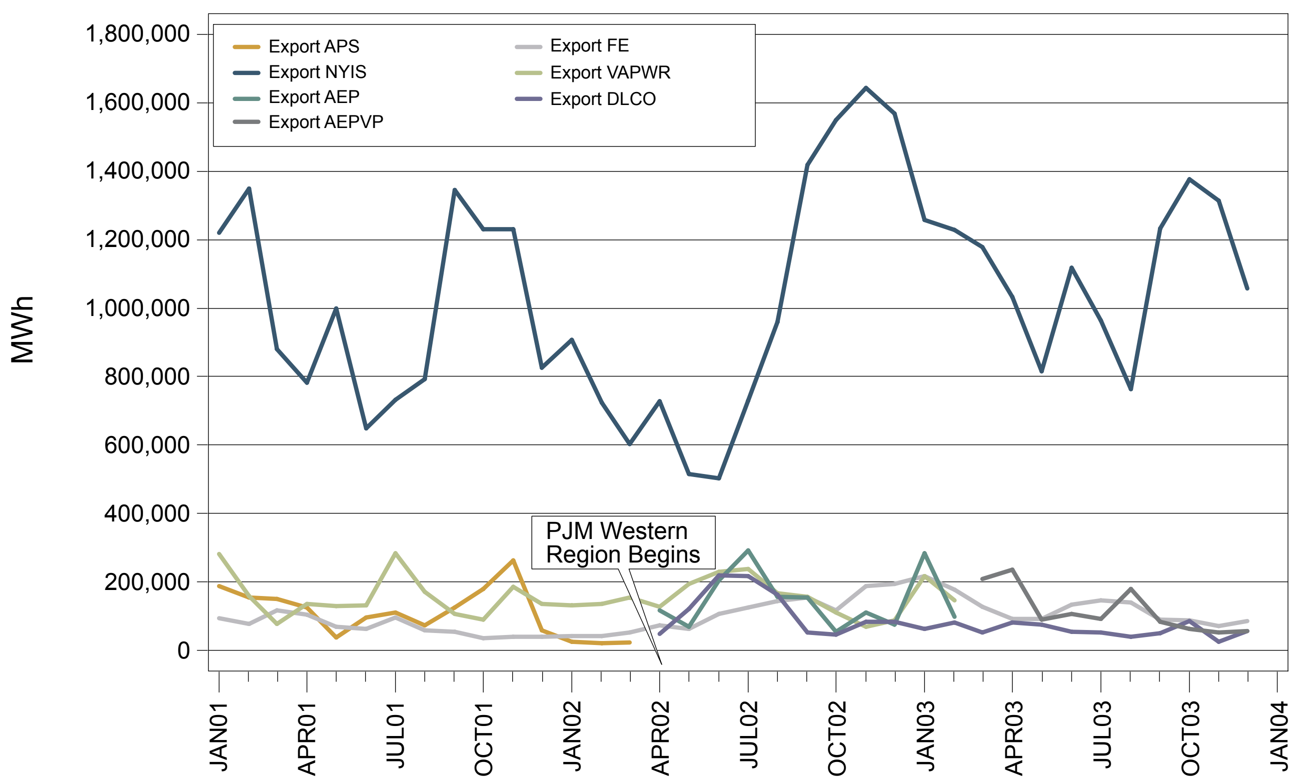


Figure 3-6 Interface Gross Exports: January 1, 2001, through December 31, 2003



Interchange Transaction Issues

Loop Flow

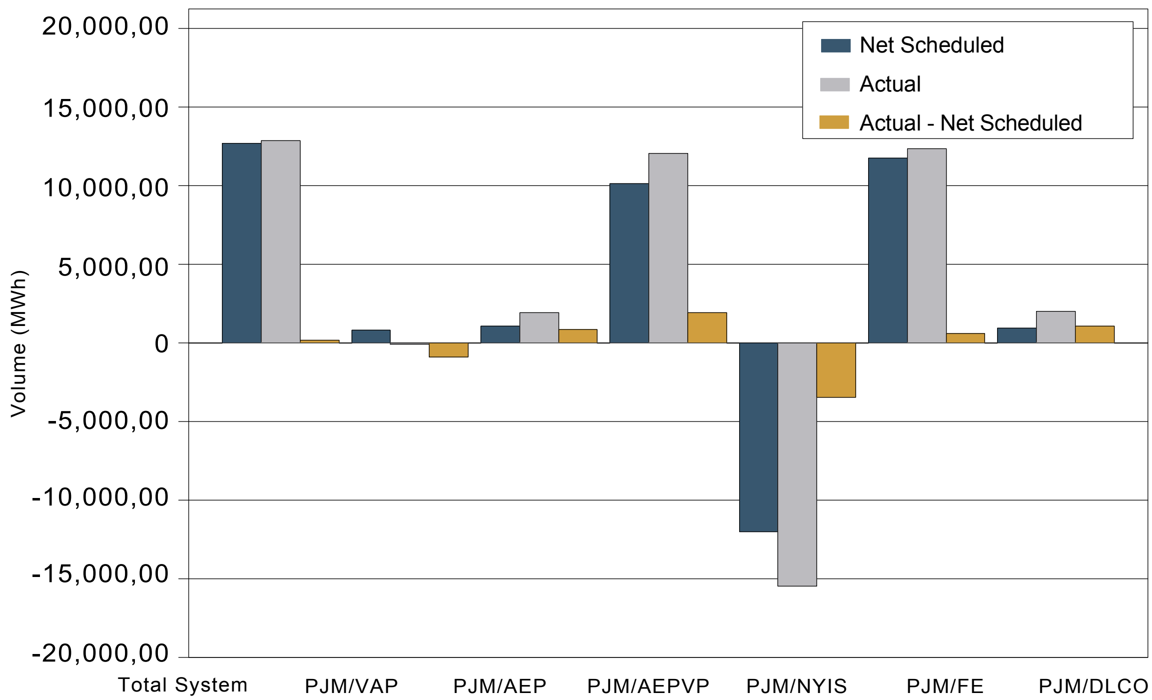
Loop flow results when the transmission contract path for energy transactions does not match the actual path of energy flows on the transmission system. Loop flows can arise from transactions scheduled into, out of, or around the PJM system. Outside of PJM's LMP-based Energy Market, energy is scheduled and paid for based on contract path although actual, associated energy deliveries flow on the path of least resistance. Loop flows can also occur when a transaction is scheduled between two external control areas, and some or all of the actual flows occur at PJM interfaces. Loop flows can result when transactions are scheduled into or out of PJM on one interface, but actually flow on another interface. Loop flows based on contract paths between external systems can only be managed by PJM using transmission loading relief (TLR) procedures. Loop flows based on gaming PJM price differentials can be managed, in part, by improving the pricing of transactions at the PJM interfaces.

Although total PJM net scheduled and actual flows were approximately equal in 2003, such was not the case for each individual interface (Figure 3-7).

For PJM as a whole, net scheduled and actual interface flows were approximately balanced in 2003. Actual total system net imports were approximately 12.9 million MWh, exceeding the scheduled total of approximately 12.7 million MWh by 0.2 million MWh or less than 2 percent. Flow balance varied, however, at each individual interface. The PJM/NYIS interface was the most out of balance, with net actual exports exceeding net scheduled by approximately 3.4 million MWh for the year or an average of 287,000 MWh per month. At the PJM/AEPVP interface, net actual imports exceeded those scheduled by approximately 1.9 million MWh or 159,000 MWh per month. Note that the separate reporting of PJM/AEP and PJM/VAP in Figure 3-7 is for the period prior to March. At the PJM/FE interface, net actual imports exceeded those scheduled by 0.6 million MWh or 51,000 MWh per month while at the PJM/DLCO interface, net actual imports exceeded net scheduled by 1.1 million MWh or 91,000 MWh per month.

PJM/NYIS replaced PJM/AEP and PJM/VAP as the more out of balance interface in 2003 compared to 2002. The primary reason for this was the combining of PJM/AEP and PJM/VAP into PJM/AEPVP in 2003. The imbalances in PJM/AEP flows (net positive 4.6 million MWh in 2002) largely offset the imbalances in PJM/VAP flows (net negative 4.0 million MWh in 2002). The result is that the net of scheduled and actual interface flows at the combined PJM/AEPVP interface is smaller and the net imbalance between scheduled and actual flows at the PJM/NYIS interface was the largest in 2003.

Figure 3-7 Net Scheduled and Actual PJM Interface Flows: 2003



Interface Pricing Issues

In a February 24, 2003, letter from the PJM Market Monitor to the PJM Members Committee and the Energy Market Committee, PJM announced that effective March 1, 2003, it would combine the previously separate PJM/AEP and PJM/VAP interfaces into PJM/AEPVP, a single interface with separate and distinct import and export pricing. As a result of its continuing investigation into loop flow and circulation on the system and into appropriate pricing points for external transactions, PJM found a clear need to further modify its rules governing pricing for external transactions. In the February 24 letter, PJM stated that it had determined that transactions that source in PJM, but sink in specified control areas should receive a price consistent with the associated actual power flows. The PJM sources for export transactions then became PJM/NYIS, PJM/FE, PJM/DLCO and PJM/AEPVPEXP, excluding the PJM/VAP or PJM/AEP interfaces. The PJM/AEPVPEXP interface consists of buses previously included in the PJM/AEP and PJM/VAP interface definitions, dynamically weighted by the specific underlying actual tie line export power flow patterns. Similarly, PJM determined that transactions that sink in PJM and source in specified control areas should receive a price consistent with the actual associated power flows. The PJM sinks for import transactions then became PJM/NYIS, PJM/FE, PJM/DLCO and PJM/AEPVPIMP, excluding the PJM/VAP and PJM/AEP interfaces. The PJM/AEPVPIMP interface consists of buses previously included in the PJM/AEP and PJM/VAP interface definitions, dynamically weighted by the specific underlying actual tie line import power flow patterns.

To reflect the actual flow of transactions linked to the PJM/AEP and PJM/VAP interfaces, PJM began on March 1, 2003, to price all transactions that source in PJM and sink in one of the relevant defined control areas[4] at the PJM/AEPVPEXP interface price. At the same time, PJM began to price all transactions that sink in PJM and source in one of the defined control areas at the PJM/AEPVPIMP interface price. Going forward, PJM intends to apply the same power-flow-based methodology for pricing transactions into and out of its control area at all interfaces. It is expected that this approach can provide consistent pricing for transactions to and from PJM that are electrically comparable, regardless of interface.

This PJM action was taken in accord with 3.3.1(d) of Schedule 1 of the "Operating Agreement," governing payment for deliveries to the PJM Spot Market. It states in relevant part: "For pool External Resources the Office of

4 See "Mapping for External Transaction Pricing," an attachment to the February 24, 2003, letter available through the PJM Web site (www.pjm.com).

the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding interface point between adjacent control areas and the area comprised of the PJM-West [PJM Western] Region and PJM Control Area [PJM Mid-Atlantic Region]."

As Table 3-1, Figure 3-8 and Figure 3-9 illustrate, the discrepancy between scheduled and actual power flows at the PJM/AEP and PJM/VAP interfaces began to increase late in 2002 and early in 2003.[5] This was particularly evident during off-peak hours (Figure 3-9). For example, the difference between monthly average actual and contract power flows at the PJM/AEP interface increased from an off-peak average of 223 MW in September 2002, to 992 MW in January 2003. Correspondingly, the difference in price between the PJM/VAP and PJM/AEP interfaces increased from an off-peak average of $3.94 per MWh in September 2002, to $24.58 in January 2003. This pattern, although not as dramatic, was also evident during the peak hours (Figure 3-8).

Implementation of the AEPVP interface price rule change had the greatest impact during off-peak periods. The loop flow pattern that was developing in the fall and winter of 2002/2003 at PJM/VAP and PJM/AEP was reduced. On peak, the rule change had a lesser impact. It was the July 2002 rule change that provided a major correction to a diverging flow pattern during on-peak hours.

The offsetting relationship between power flow discrepancies at the PJM/AEP and PJM/VAP interfaces is clearly evident in both on-peak and off-peak data before March 2003. The flow discrepancy at the PJM/AEP interface was approximately equal to and opposite from the discrepancy at the PJM/VAP interface. The pattern was clear during all time periods monitored since the PJM/AEP interface had been developed in April 2002. Although the July 2002 rule change had the effect of mitigating its amplitude, it did not change the opposing pattern; however, the AEPVP rule change has brought a pattern-changing effect on the interface flow discrepancies. Since March 2003, the PJM/AEP and PJM/VAP flows have not exhibited the previously observed relationship. In fact, the MW discrepancy at PJM/VAP has diminished considerably and, rather than being consistently negative, has varied between positive and negative with little apparent relationship to the flows at the PJM/AEP interface. The PJM/AEP discrepancies have continued, but at a much lower MW value, again with little apparent relationship to PJM/VAP. The change to directional (i.e., import and export) pricing has altered the pricing signal from one based on location to one based on location and direction. Previously high prices at PJM/VAP, which created an incentive to schedule imports, no longer exist because PJM/VAP is no longer a pricing point. Instead, PJM now has price signals that more accurately reflect the value of import and export transactions at the combined PJM/AEPVP interface.

The July 2002 and the March 2003 AEPVP rule changes combined to produce the desired effect on power flow discrepancies at PJM/AEP and PJM/VAP. The magnitude of actual versus scheduled values for both interfaces declined significantly. Additionally, the offsetting relationship between flows at the two interfaces has been greatly reduced. The July 2002 changes appear to have had a greater effect on on-peak hours, but although reducing the magnitude of the loop flows, did not change the pattern between PJM/AEP and PJM/VAP. Off-peak periods were not as greatly affected by the change. The AEPVP rule change had its biggest impact on off-peak periods and did change the offsetting relationship between MW flows at the two interfaces, most likely because of the directional pricing aspect of the rule change.

On August 1, 2003, PJM implemented a new interface price point when it added PJM/IMO to the existing four interface price points. PJM created the PJM/IMO price point to reflect more accurately the actual power flow from sources located in IMO. Prior to August 1, the interface pricing rules set the price for power coming from and/or going to IMO at the PJM/NYIS interface price. The loop flow investigation determined that actual flow path of sources located in IMO was not primarily through PJM/NYIS, but was split between the PJM/NYIS and PJM's Western Interfaces. Some transactions sourced in IMO were cut by PJM based on their impact on PJM's western interface facilities. These transactions were responding to the price signal at the PJM/NYIS interface while their actual flow was split between PJM/NYIS and PJM's Western Interfaces. The PJM/IMO interface price is based on a generator bus located in IMO.

5 The referenced table and all figures begin at April 1, 2002, when the PJM Western Region was integrated and PJM/AEP was created.

Table 3-1 Interface LMP Differentials and Actual-Schedule Differential

2003 Periods

	Jan	Feb	Mar	Apr	May	June	July	July 1 thru 19	July 20 thru 31	Aug	Sept	Oct	Nov	Dec
Peak-Hour Periods														
$VAP-$AEP/ $AEPVPIMP- $AEPVPEXP ($/MWh)	$9.18	$1.06	$ (2.06)	$ (1.08)	$ (8.11)	$ (10.85)	$ (7.55)	na	na	$ (1.08)	$ (6.45)	$ (2.17)	$ (2.44)	$ (0.41)
VAP Act - Sch (MW)	-909	-277	-52	-288	133	-95	-194	na	na	114	-106	-568	-440	29
AEP Act - Sch (MW)	726	179	50	248	982	701	629	na	na	245	390	359	778	264
AEPVP Act-Sch (MW)			-2	-40	1,115	606	435	na	na	359	283	-209	24	293
Off-Peak Hour Periods														
$VAP-$AEP/ $AEPVPIMP- $AEPVPEXP ($/MWh)	$24.58	$4.92	$ (5.69)	$ (0.61)	$ (3.11)	$ (3.21)	$ (6.82)	na	na	$ (2.09)	$ (1.22)	$ (1.35)	$ (1.10)	$ (0.87)
VAP Act - Sch (MW)	-998	-296	-134	-106	337	333	237	na	na	240	188	-326	-551	48
AEP Act - Sch (MW)	992.33	495.3	167.45	125	189	-1	186	na	na	22	348	89	534	235
AEPVP Act-Sch (MW)			33	18	525	332	423	na	na	262	536	-237	9	283

2002 Periods

	Jan	Feb	Mar	Apr	May	June	July	July 1 thru 19	July 20 thru 31	Aug	Sept	Oct	Nov	Dec
Peak-Hour Periods														
$VAP-$AEP/ $AEPVPIMP- $AEPVPEXP ($/MWh)	na	na	na	$7.19	$6.49	$14.33	$14.06	$16.44	$9.88	$10.12	$4.86	$7.36	$5.57	$ 11.70
VAP Act - Sch (MW)	na	na	na	-533	-748	-1,323	-1,327	-1,577	-891	-295	-507	-641	-668	-955
AEP Act - Sch (MW)	na	na	na	904	1,042	1,561	1,442	1,821	780	359	479	673	606	715
AEPVP Act-Sch (MW)														
Off-Peak Hour Periods														
$VAP-$AEP/ $AEPVPIMP- $AEPVPEXP ($/MWh)	na	na	na	$ 5.13	$ 0.01	$ 4.87	$ 6.16	$ 7.41	$ 4.38	$ 4.39	$ 3.94	$ 6.49	$ 3.61	$ 8.56
VAP Act - Sch (MW)	na	na	na	-582	-460	-346	-364	-457	-229	-346	-205	-299	-574	-809
AEP Act - Sch (MW)	na	na	na	740	459	457	476	633	251	457	223	504	687	778
AEPVP Act-Sch (MW)														

Figure 3-8 PJM/AEP and PJM/VAP: Peak Hour Average Values

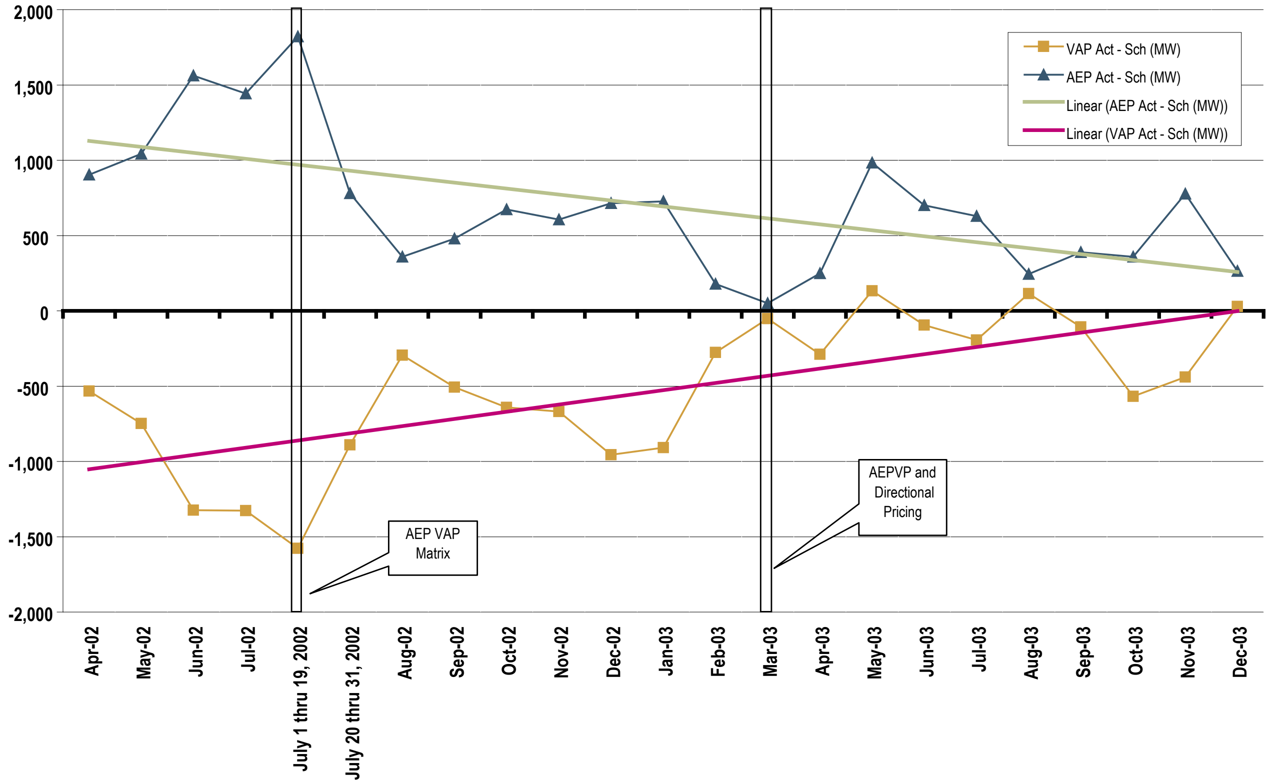
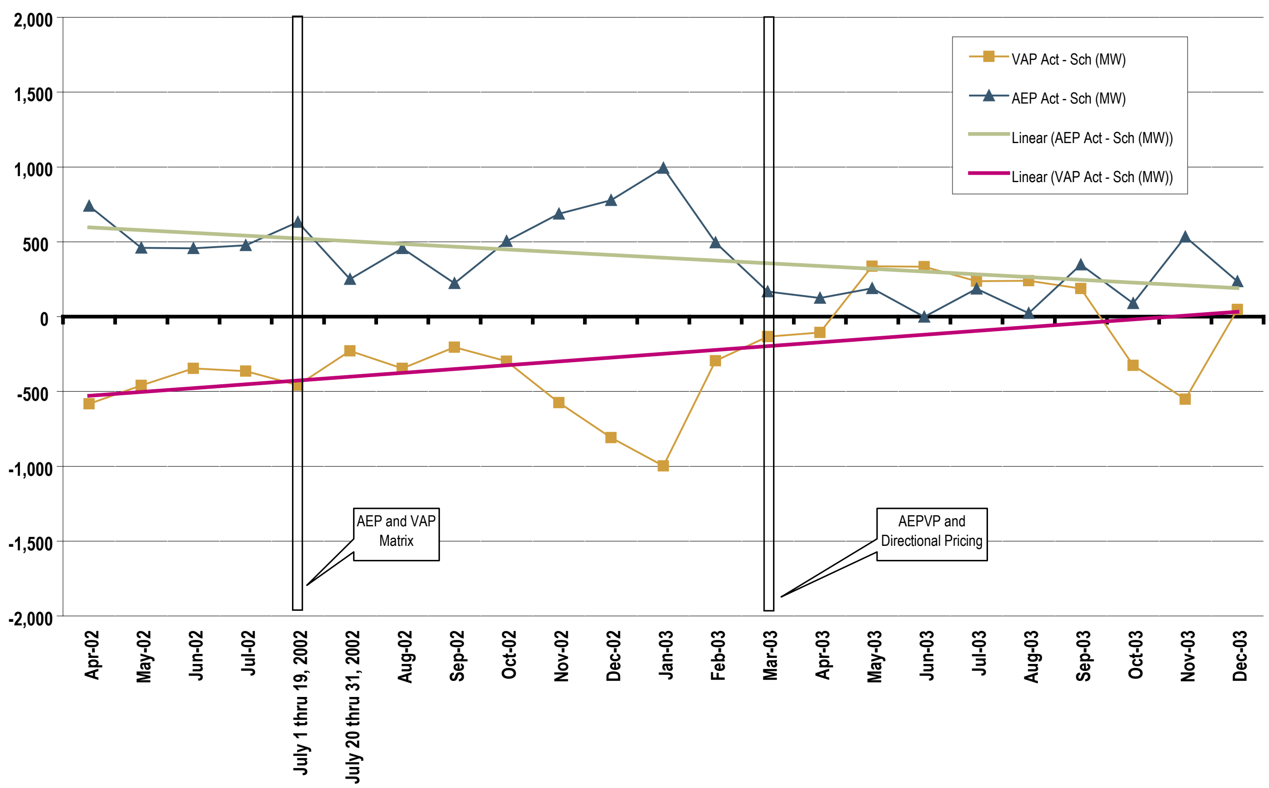


Figure 3-9 PJM/AEP and PJM/VAP: Off-Peak Hour Average Values



PJM and NYISO Transaction Issues

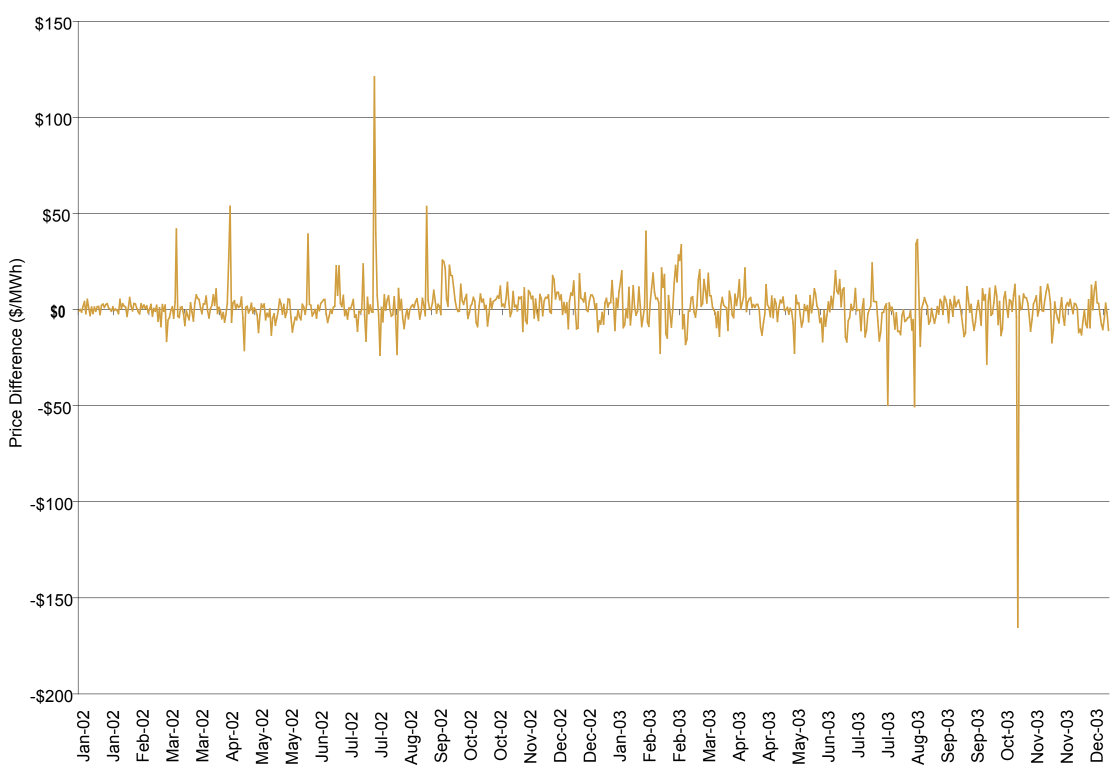
If the interface prices were defined in a comparable manner by PJM and the NYISO, if there were identical rules governing external transactions in PJM and the NYISO, if there were no time lags built into the rules governing such transactions and if there were no risks associated with such transactions, 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 exist is important in explaining the observed relationship between interface prices and the observed relationship between inter-ISO power flows and those price differentials.

The simple average difference in interface prices for the PJM/NYIS and the NYISO PJM Proxy bus decreased from 2002 to 2003, while the variability in the difference increased. The simple average PJM NYISO interface price difference was $2.32 per MWh in 2002 and $0.34 per MWh in 2003 (Figure 3-10). Nevertheless, the simple average interface prices does not make explicit the substantial underlying hourly variability in prices and the difference in simple average prices similarly does not make explicit that substantial differences in price existed over the course of both 2002 and 2003.

The difference between the PJM/NYIS interface price and the NYISO PJM Proxy bus price fluctuates. At times the PJM/NYIS price has been higher and at other times the NYISO PJM Proxy bus price has been higher. In fact on average during 2002 and 2003, the difference fluctuated between positive and negative more than seven times a day. There was no trend in the number of times that the price difference fluctuated; it remained relatively constant over the 2002 to 2003 period.

Standard deviation is a direct measure of variability. The standard deviation of hourly price was $19.52 in 2002 and $25.00 in 2003 for PJM/NYIS and $31.65 in 2002 and $37.72 in 2003 for the NYISO PJM Proxy bus. The standard deviation of the difference in interface prices was $27.88 in 2002 and $36.21 in 2003. The absolute value of the price differences is another measure of price variability. The average of the absolute value of the hourly price difference was $10.17 in 2002 and $16.13 in 2003. Absolute values reflect the price differences without regard to whether they are positive or negative.

Figure 3-10 Daily Hourly Average Price Difference (NY Proxy - PJM/NYIS)

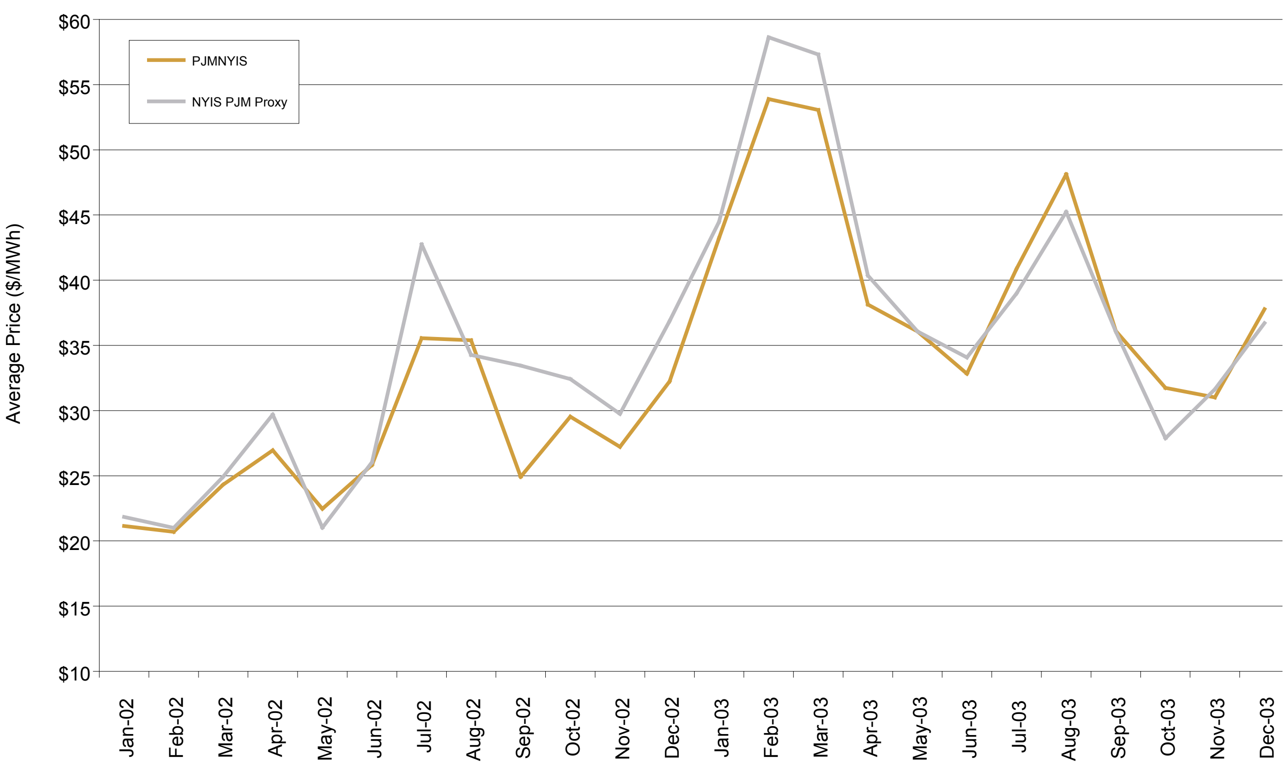


A number of factors are responsible for the observed relationship between interface prices. The fact that the simple average of interface prices is relatively small suggests that competitive forces prevent price deviations from persisting. That is further supported by the frequency with which the price differential switches between positive and negative. 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.

PJM defines the PJM/NYIS interface price based on flow-weighted LMPs on two specific lines that physically connect PJM and the NYISO. By contrast, the NYISO defines the NYISO PJM Proxy bus price using a single point inside PJM. Different definitions mean that the PJM and NYISO interface prices reflect different pricing dynamics including different levels of congestion. A closer relationship between interface prices would be expected if the prices were defined by PJM and the NYISO on the same tie lines, in the same flow-weighted manner and at points close to the border in PJM and in the NYISO.

In addition to the small average interface price differences and the large variability in the hourly price differences, there is a significant correlation between monthly average hourly PJM and NYISO interface prices over the entire 2002-2003 period (Figure 3-11). There is also a significant correlation between hourly PJM and NYSIO interface prices over the entire 2002-2003 period.

Figure 3-11 Monthly Hourly Average NYISO PJM Proxy Bus Price and the PJM/NYIS Price



The apparently somewhat weak observed relationship between the PJM and NYISO power flows and the corresponding interface price differences are, in significant part, functions of differences in rules governing external transactions in PJM and the NYISO as well as of the time lags built into those rules. There is no statistically significant relationship between such power flows and the contemporaneous interface price differential. Similarly, there is no statistically significant relationship between such power flows and the interface price differential one hour prior to the power flows. However, there is a statistically significant relationship between such power flows and the interface price differential two hours prior to the power flows. This pattern is consistent with both the time lags built into the transaction rules and the uncertainty built into those rules.

The rules governing transactions limit the timeliness with which market participants can react to real-time price differences and the extent to which they can benefit from real-time price spreads. In addition, participants may enter into longer term transactions under which the physical flows may not be a direct function of the hourly price differences between the interface prices. While this is not a reason to expect persistent price differences, it is consistent with data on interface price differences and the volumes and directions of power flows.

The nature of the relationship between the hourly price at PJM's New York interface and the price at NYISO's PJM proxy bus appears to be the result of differences in market rules governing transactions at the two independent system operators.[6] In real time, PJM market participants request transactions at PJM interfaces that are accepted and scheduled by PJM based on the physical limits of the system. The transaction request can be scheduled to begin on any quarter of the hour. These transactions are price takers in real time and do not submit 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. 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 balancing market evaluation (BME) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of BME timing, market participants are required to submit their bid or offer 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 time which can be any quarter hour. The duration of the requested transaction can vary from a single hour to an unlimited amount of time. Generally PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, only about 4 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 given a variety of factors, including ramp room. 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.

The NYISO rules provide that BME results are available 40 minutes prior to the operating hour. Thus winning bidders have 20 minutes from the time when BME results indicate that their transaction will flow until the time when they must get their transaction cleared with PJM to meet its 20-minute requirement. To get a transaction cleared with PJM, the market participant must have a valid 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 could be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resultant uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

6 The NYISO is implementing a new real-time scheduling system that is expected to address some of the issues addressed here.

Section 4 – Capacity Markets

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

The PJM Capacity Credit Market provides a mechanism 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, Monthly and Multimonthly Capacity Credit Markets. The 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.

The PJM Market Monitoring Unit (MMU) recommended in its "2002 State of the Market Report" that the PJM Mid-Atlantic and Western Regions' separate Capacity Credit Markets be combined into a single market with one set of rules. That recommendation was implemented by PJM on June 1, 2003.

Overview

The MMU analyzed key measures of PJM Capacity Market structure and performance for 2003, including concentration ratios, prices, outage rates and reliability. The MMU found serious market structure issues, but no exercise of market power during 2003.

The PJM Mid-Atlantic Region's Capacity Market results were competitive during 2003. The PJM Western Region's Capacity Market did not operate in a meaningful way during 2003. There was not a functioning competitive market in the PJM Western Region. Beginning June 1, 2003, the two markets were combined into a single market with rules identical to those that had previously provided the operating framework for the Capacity Market in the PJM Mid-Atlantic Region alone. Inclusion of the PJM Western Region's Capacity Market in a broader capacity market is a positive step. Nonetheless, market power remains a serious concern for the MMU in the Capacity Market.

Market Structure

PJM Mid-Atlantic Region: January through May 2003

- **Supply.** Structural analysis of the PJM Mid-Atlantic Region's Capacity Credit Market found that short-term markets exhibited moderate concentration and long-term markets exhibited high concentration levels in 2003.

- **Demand.** During 2003, the original PJM Mid-Atlantic Region electric utilities and their affiliates accounted for 90 percent of the PJM Mid-Atlantic Region's load obligations.

- **Supply and Demand.** During the first interval[2] of 2003, installed capacity, unforced capacity and obligations grew in the PJM Mid-Atlantic Region. Compared to the same period of 2002, average installed capacity increased by 2,615 MW or 4.3 percent to 64,075 MW, while average unforced capacity rose by 2,467 MW or 4.2 percent to 60,960 MW. Average load obligations climbed by 2,992 MW or 5.3 percent to 59,630 MW,

1 See Appendix E, "Glossary," for definitions of PJM Capacity Credit Market terms.

2 PJM defines three intervals for PJM 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.

or 1,330 MW less than average unforced capacity. During the first interval, overall Capacity Credit Market transactions increased by nearly 22 percent. Daily Capacity Credit Market volume increased by 112 percent, while Monthly and Multimonthly Capacity Credit Market volume increased by 7.2 percent and 14.2 percent, respectively.

PJM Western Region: January through May 2003

- **Supply.** Structural analysis of the PJM Western Region's Capacity Credit Markets found extremely high concentration levels in the first interval of 2003.

- **Demand.** During the first interval of 2003, the original PJM Western Region electric utility accounted for 96.9 percent of the PJM Western Region's load obligations.

- **Supply and Demand.** In the first interval of 2003, the PJM Western Region's average installed capacity was 10,293 MW and the average available capacity was 8,482 MW. The average capacity obligation was 6,817 MW while the maximum capacity obligation was 9,002. The Capacity Credit Market was effectively not operating in the PJM Western Region during the first interval of 2003.

PJM: June through December 2003

- **Supply.** Structural analysis of the combined PJM Mid-Atlantic and Western Regions' Capacity Credit Markets found that high concentration levels were exhibited during the last two intervals of 2003.

- **Demand.** During the last two intervals of 2003, the original electric utilities in the two regions and their affiliates accounted for 85.8 percent of systemwide PJM load obligations.

- **Supply and Demand.** During the last two intervals of 2003, installed capacity, unforced capacity and obligations grew in PJM with respect to the same time period last year. Compared to the same period of 2002, average installed capacity increased by 4,774 MW or 6.5 percent to 77,728 MW. Average load obligations climbed to 70,203 MW. Overall, Capacity Credit Market transactions increased to 4,740 MW while Daily Capacity Credit Market volume increased to 1,120 MW. Monthly Capacity Credit Market volume decreased to 746 MW, but Multimonthly Capacity Credit Market volume rose to 2,874 MW. [3]

Market Performance

PJM Mid-Atlantic Region: January through May 2003

- **Prices.** Daily Capacity Credit Market prices were low during the first interval of 2003, averaging $6.00 per MW-day. Prices in the monthly and multimonthly markets declined slightly over the interval from $21.14 per MW-day in January to $16.87 per MW-day in May, averaging $17.36 per MW-day for the first interval.

PJM Western Region: January through May 2003

- **Prices.** Daily Capacity Market prices averaged $0.02 per MW-day. There were no trades in the monthly and multimonthly markets during 2003.

- **Volumes.** There was very little activity in the Capacity Credit Markets during the first interval of 2003. An average 0.15 MW traded in the daily market. Trades occurred on only three separate days. No trades were completed in the monthly or multimonthly markets. One very small 0.1 MW multimonthly trade from 2002 was effective through May 31, 2003.

3 Since some of the measures of capacity market supply and demand were in different units for the Mid-Atlantic and Western Regions (e.g. unforced MW for the Mid-Atlantic Region and available MW for the Western Region), these measures cannot be directly compared.

PJM: June through December 2003

- **Prices.** Daily Capacity Credit Market prices were quite low during the last two intervals of 2003, averaging \$0.68 per MW-day. Prices in the monthly and multimonthly markets declined over that period from \$36.46 per MW-day in June to \$11.26 per MW-day in December, averaging \$24.18 per MW-day.

- **Availability.** Between 1996 and 2001, the average PJM forced outage rate (EFORd) trended downward, reaching 4.8 percent in 2001 and then increased to 5.2 percent in 2002 and 7.1 percent in 2003. The increase in EFORd of 1.9 percent from 2002 to 2003 was the result of increased forced outage rates across all unit types.

Given the basic features of Capacity Market structure in both the PJM Mid-Atlantic and the PJM Western Regions, 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 likelihood of the exercise of market power is high. Market power is structurally endemic to PJM Capacity Markets. Supply and demand fundamentals offset these market structure issues in the PJM Mid-Atlantic Region's Capacity Market in 2003, producing competitive results. In the PJM Western Region's Capacity Market, the dominance of a single supplier and the extremely small load levels served by independent LSEs meant that there was not a functioning competitive market in the PJM Western Region prior to the inclusion of the PJM Western Region in the PJM Capacity Market.

Market Structure

PJM Mid-Atlantic Region: January through May 2003

Supply Side

Concentration ratios[4] are a summary measure of market share, a key element of market structure. High concentration ratios mean that a comparatively small number of sellers dominates a market, while low concentration ratios mean that a larger number of sellers shares market sales more equally. Concentration measures must be applied carefully in assessing the competitiveness of markets. Low aggregate market concentration ratios do not establish that a market is competitive, that market participants cannot exercise market power or that concentration is not high in particular geographic market areas. High aggregate market concentration ratios do, however, indicate an increased potential for market participants to exercise market power.

The MMU structural analysis indicates that the PJM Mid-Atlantic Region's Capacity Credit Markets in the first interval of 2003 exhibited moderate levels of concentration in the Daily Capacity Credit Markets and high levels of concentration in the Monthly and Multimonthly Capacity Credit Markets. As shown in Table 4-1, HHIs for Daily Capacity Credit Markets averaged 1521 during 2003, with a maximum of 1972 and a minimum of 1078 (four firms with equal market shares would result in an HHI of 2500). HHIs for the longer term Monthly and Multimonthly Capacity Credit Markets averaged 3090, with a maximum of 5173 and a minimum of 1288 (three firms with equal market shares would result in an HHI of 3333). On average 602 MW were traded in the Daily Capacity Credit Markets and 3,177 MW were traded in the Monthly and Multimonthly Capacity Credit Markets. The total of 3,779 MW represented, on average, 6.3 percent of total load obligation for the period of which 1 percent was attributable to the Daily Capacity Credit Market and 5.3 percent was attributable to the Monthly and Multimonthly Capacity Credit Market.

4 See Section 2, "Energy Market," for a discussion of concentration ratios and the HHI.

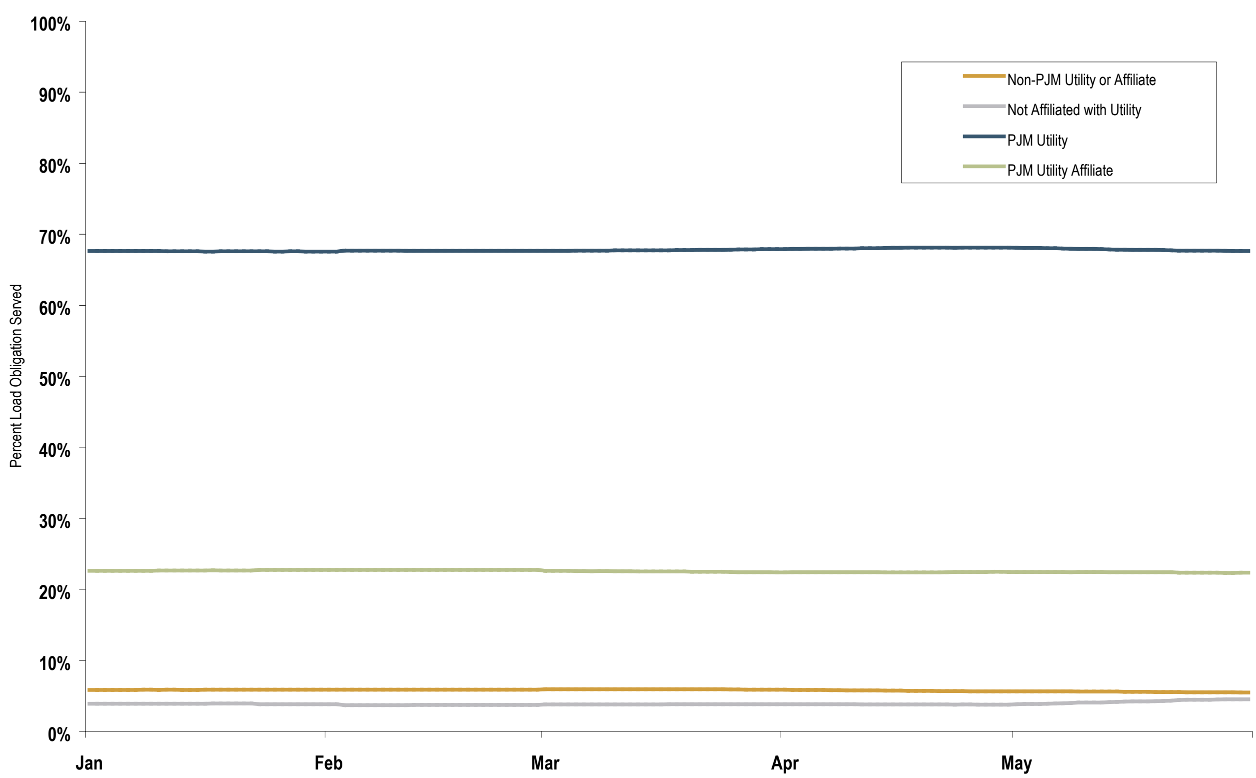
Table 4-1 PJM Capacity Market HHI: 2003

Term	Region	Statistic	Daily Market HHI	Monthly and Mutlimonthly Market HHI
Jan. through May	PJM Mid-Atlantic Region	Average	1521	3090
		Minimum	1078	1288
		Maximum	1972	5173
June through Dec.	PJM	Average	2155	2479
		Minimum	1262	1430
		Maximum	3071	6180
Jan. through Dec.	PJM	Average	2003	2711
		Minimum	1078	1288
		Maximum	3071	6180

Demand Side

During the first interval of 2003, PJM electric utility companies (the original PJM electric utilities) and their affiliates maintained their market share of PJM Mid-Atlantic Region load obligations, averaging 90.3 percent (Figure 4-1). The market share of PJM electric utility companies averaged 67.8 percent of the PJM Mid-Atlantic Region's load. The market share of the affiliates of PJM electric utilities averaged 22.5 percent. The market share of LSEs not affiliated with a utility was about 4 percent and the market share of non-PJM utilities and their affiliates averaged about 6 percent.

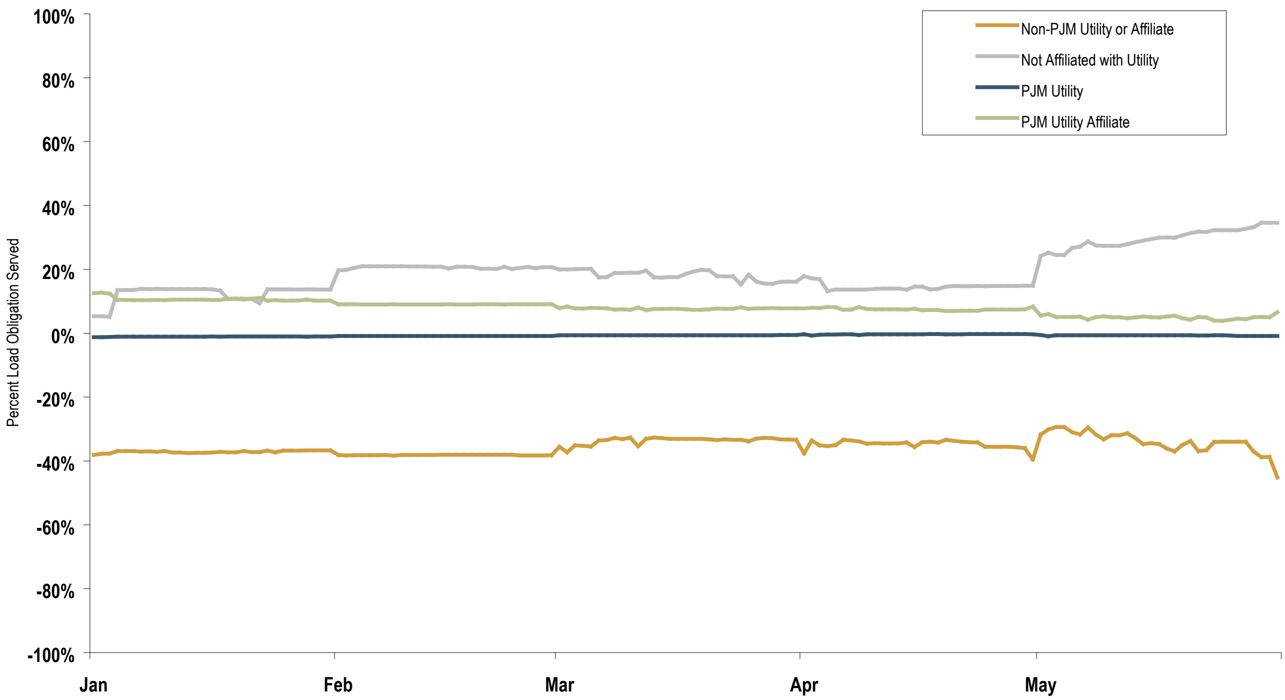
Figure 4-1 Percent of PJM Mid-Atlantic Region Load Obligation Served: January through May 2003



During the first interval of 2003, reliance on the PJM Mid-Atlantic Region's Capacity Credit Markets varied by sector. As Figure 4-2 shows, PJM electric utilities relied on Capacity Credit Markets for an average of -0.7 percent of their first interval 2003 unforced capacity obligation while their affiliates relied on Capacity Credit Markets for an average of 7.9 percent of theirs. Affiliates of non-PJM electric utilities obtained an average of -35.5 percent of their unforced capacity obligations from the Capacity Credit Markets (they were net sellers) while unaffiliated LSEs obtained an average of 19.1 percent of their capacity obligations from the Capacity Credit Markets. The measure of Capacity Credit Market reliance is the sector's daily net Capacity Credit Market position divided by the sector's capacity obligation (This excludes self-supply and bilateral transactions.) Thus, a negative share means that a sector has sold more capacity credits than it has purchased for a day.

During the first interval of 2003, LSEs unaffiliated with any utilities increased their reliance on Capacity Credit Markets from approximately 5 percent to about 35 percent. These entities nearly doubled the amount of load obligation served during the first interval. The proportion of load obligation served in the Capacity Credit Markets fluctuated for non-PJM utilities and their affiliates based on changes in capacity obligations and activity in the Capacity Credit Markets.

Figure 4-2 Percent of Load Obligation Served by the PJM Mid-Atlantic Region's Capacity Credit Market: January through May 2003



Supply and Demand

In the first interval of 2003, capacity resources exceeded capacity obligations in the PJM Mid-Atlantic Region on every day. The pool was long by an average of 1,330 MW. The amount of capacity resources in the PJM Mid-Atlantic Region on any day reflects the addition of new resources, the retirement of old ones and the importing or exporting of capacity resources, decisions that are functions of market forces. The total pool capacity obligation is set annually via an administrative process.

System net excess capacity can be determined using unforced capacity, obligation, the sum of members' excesses and the sum of members' deficiencies. Table 4-2 presents these data for the first interval of 2003.[5] Net excess is the net pool position, calculated by subtracting obligations from capacity resources. Since obligations include expected load plus a reserve margin, a net pool position of zero is consistent with established reliability objectives.

5 These data are posted on a monthly basis at www.pjm.com under the Market Monitoring Link.

Table 4-2 The PJM Mid-Atlantic Region's Member Capacity Summary: January through May 2003 (in MW)

PJM Mid-Atlantic Region	Mean	Standard Deviation	Minimum	Maximum	Change from 2002	Percent
Installed Capacity	64,075	335	63,561	64,723	2,615	4.3%
Unforced Capacity	60,960	295	60,548	61,575	2,467	4.2%
Obligation	59,630	0	59,630	59,631	2,992	5.3%
Sum of Excess	1,330	295	917	1,944	-606	-31.3%
Sum of Deficiency	0	2	0	19	-81	-99.7%
Net Excess	1,329	295	917	1,944	-525	-28.3%
Imports	888	232	695	1,236	-586	-39.8%
Exports	1,020	274	766	1,550	721	241.1%
Net Exports	132	429	-357	855	1,307	-111.2%
Unit-Specific Transactions	46,797	1,423	45,245	48,709	18,624	66.1%
Capacity Credit Transactions	64,715	1,990	62,675	67,590	20,096	45.0%
Internal Bilateral Transactions	111,511	3,387	108,177	116,101	38,721	53.2%
Daily Capacity Credits	602	185	413	1,085	318	112.0%
Monthly Capacity Credits	639	93	477	737	43	7.2%
Multimonthly Capacity Credits	2,538	169	2,251	2,688	316	14.2%
All Capacity Credits	3,779	320	3,343	4,463	677	21.8%
ALM Credits	1,292	0	1,292	1,292	-671	-34.2%

Figure 4-3 The PJM Mid-Atlantic Region's Capacity Obligations: January through May 2003

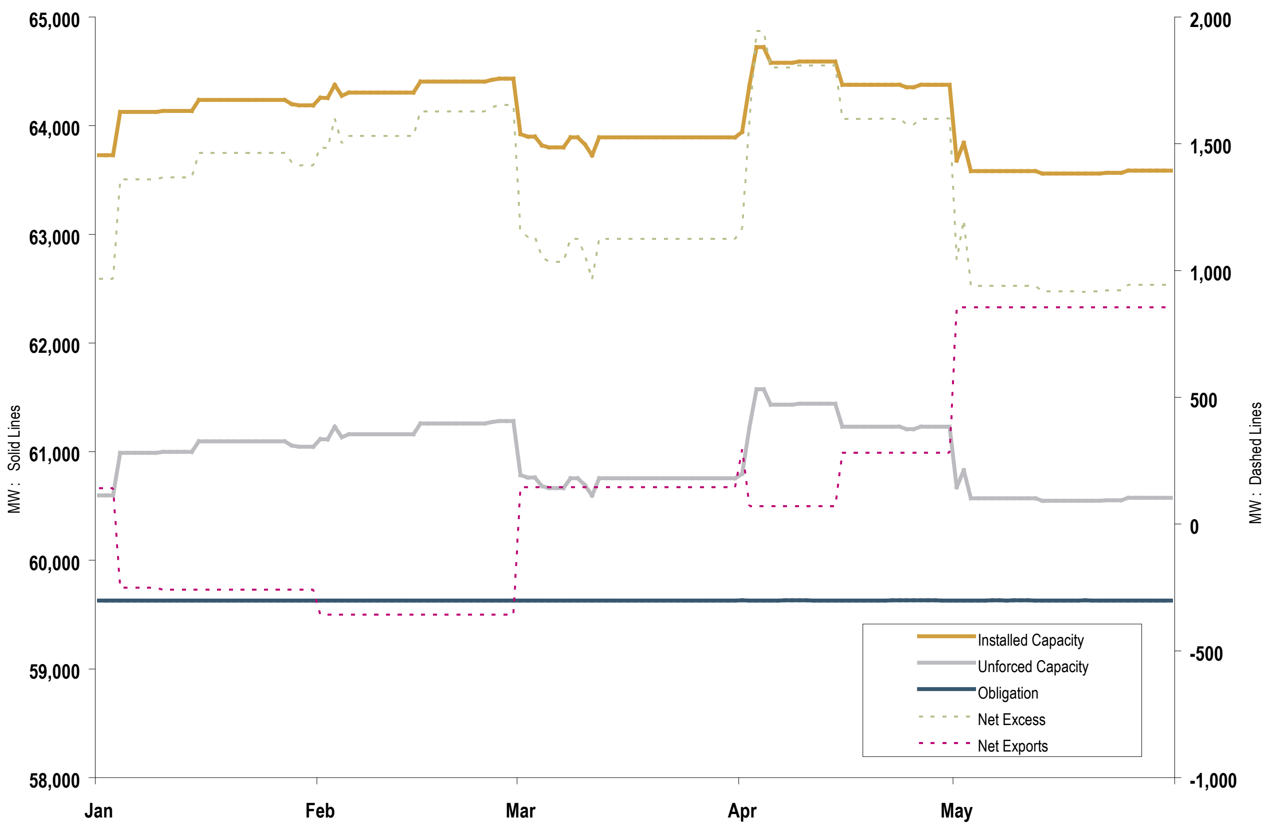
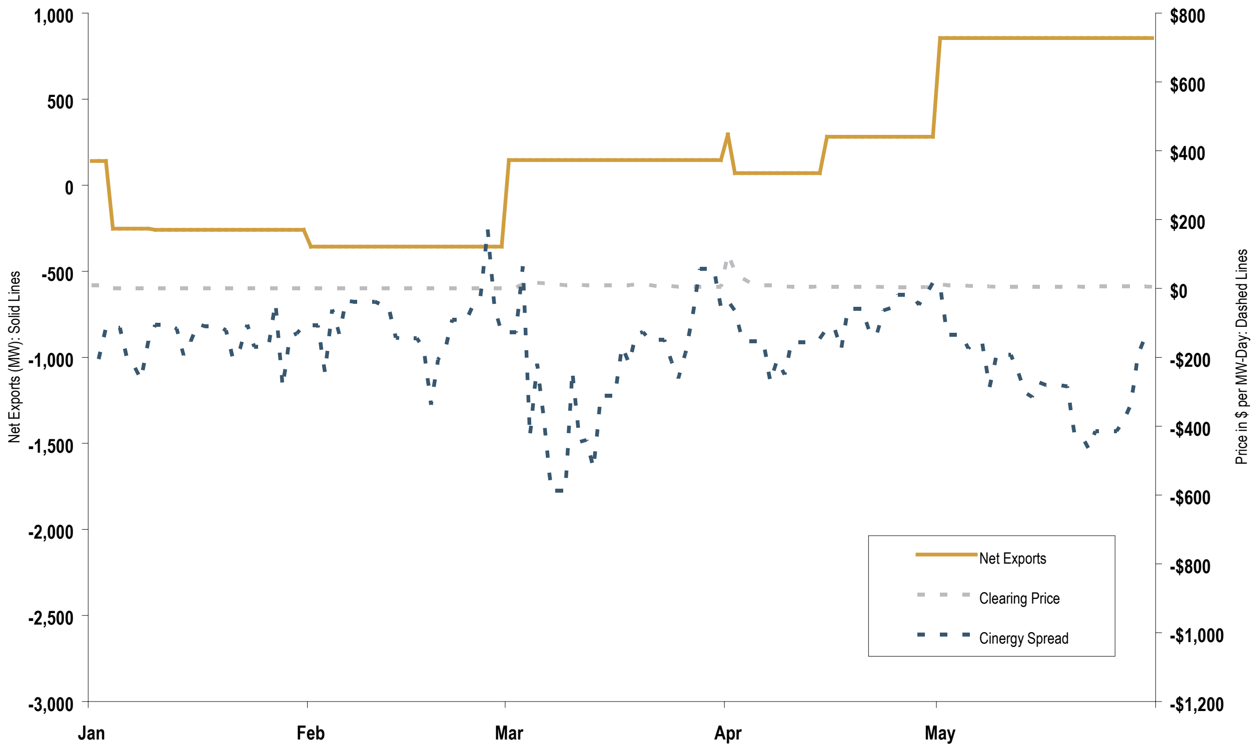


Figure 4-4 The PJM Mid-Atlantic Region's Daily Capacity Credit Market Clearing Price and Cinergy Spread versus Its Net Exports: January through May 2003



As shown in Figure 4-3 and Figure 4-4, capacity owners increased external sales of capacity resources toward the end of the first interval (May) even though the external, daily forward energy prices were generally less than the PJM Mid-Atlantic Region's prices. Starting in May 2003, there were approximately 1,200 MW exported to New York for its summer period (May through October). The PJM Mid-Atlantic Region's price in these graphs is the firm, daily forward on-peak PJM Mid-Atlantic Region Western Hub energy price, while the external price is the firm, daily forward on-peak price for Cinergy.[6]

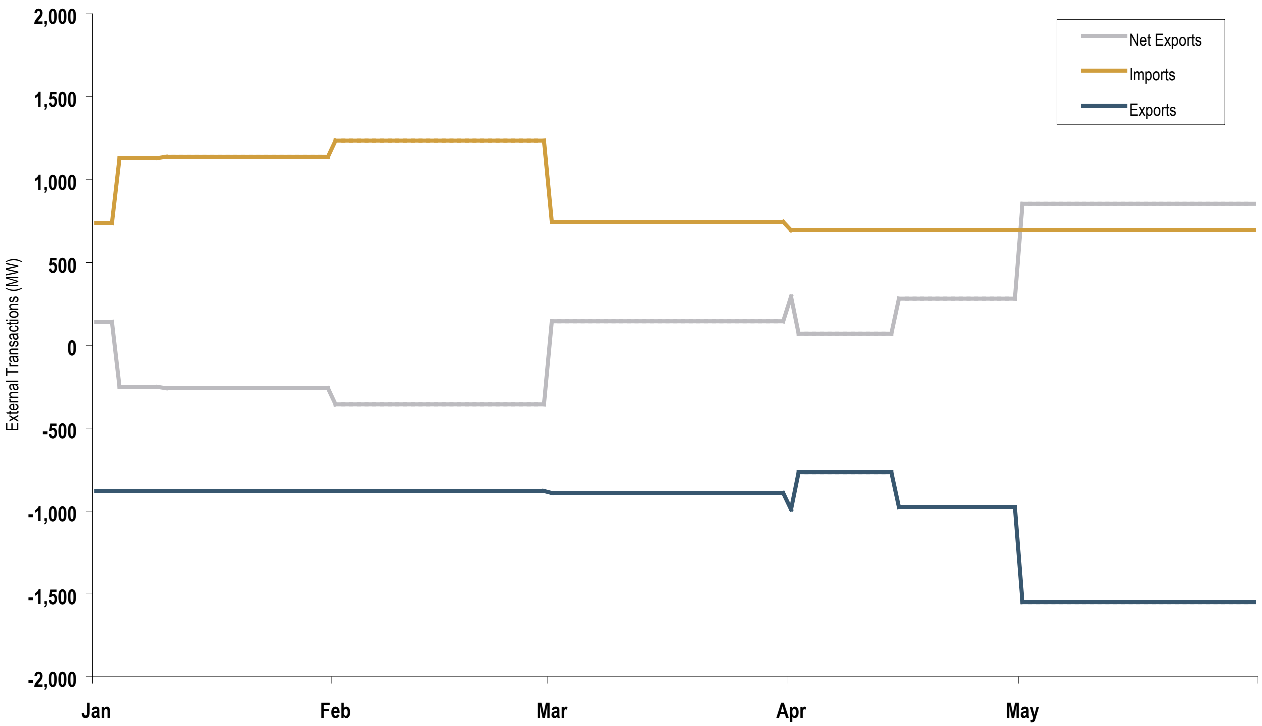
External Capacity Transactions

PJM Mid-Atlantic Region capacity resources may be traded bilaterally within and outside of the PJM Mid-Atlantic Region. Figure 4-5 presents PJM Mid-Atlantic Region external bilateral capacity transaction data for the first interval of 2003 (Table 4-2 also includes data on imports and exports.) During the first interval, an average of 888 MW of capacity resources was imported into the PJM Mid-Atlantic Region while an average of 1,020 MW was exported (delisted), resulting in an average net export of 132 MW of capacity resources. The maximum level of exports was 1,550 MW, while the maximum import was 1,236 MW. Imports decreased by about 500 MW on March 1, 2003 (see Figure 4-5) and the PJM Mid-Atlantic Region became a net exporter of capacity as a result. Exports rose by about 600 MW on May 1, 2003, and net exports of capacity from the PJM Mid-Atlantic Region increased. Compared to the first interval in 2002, exports rose by 241 percent and imports decreased by about 40 percent. PJM was a net importer of capacity in the first interval of 2002.

The May 1, 2003, export increase was a combination of a 600 MW reduction of capacity exports to a non-NYISO control area and a 1,200 MW increase in exports to the NYISO control area in response to changes in the NYISO capacity markets. These exports to the NYISO capacity market contributed to slightly higher Capacity Market prices in the PJM monthly markets. Analysis suggests that there was a price impact resulting from the increased exports to the NYISO capacity market although the price increase was no more than $5.00 per MW-day because PJM had excess capacity even after the increase in net exports.

6 These daily forward prices are on-peak prices.

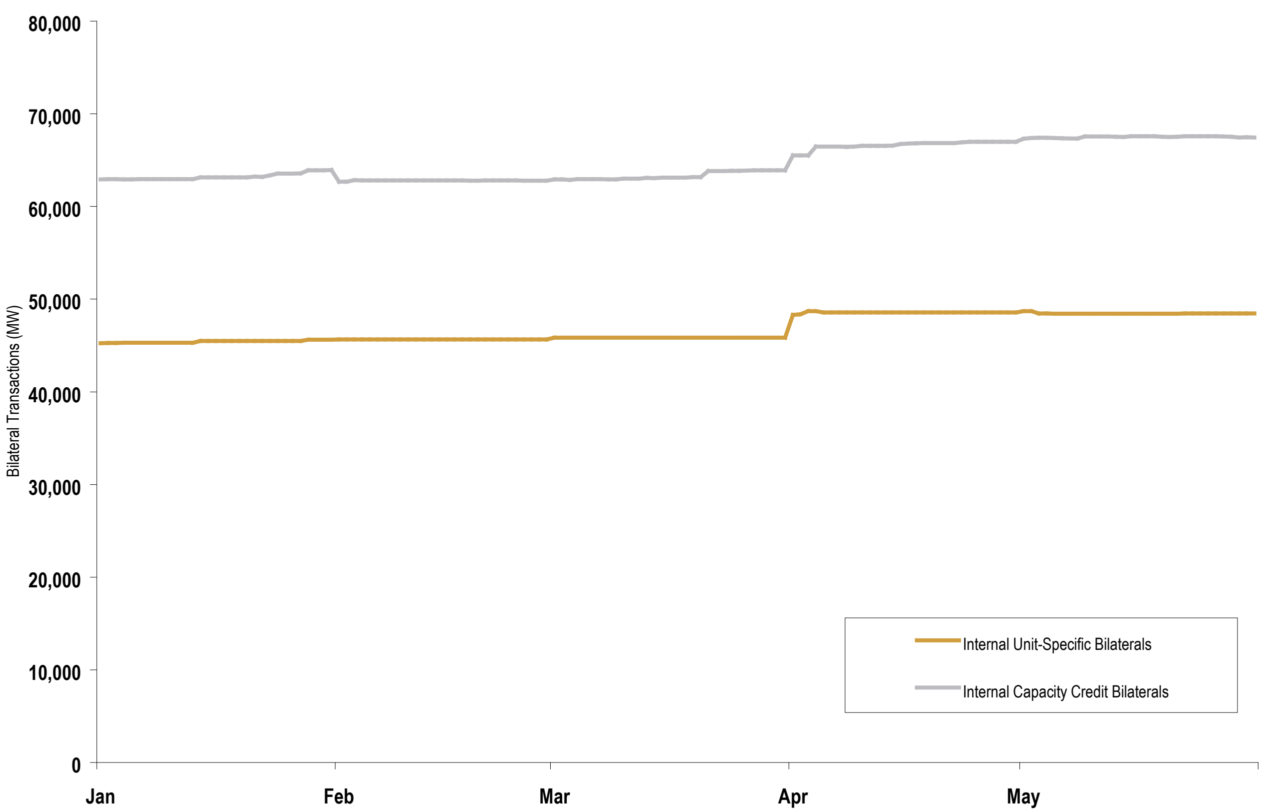
Figure 4-5 The PJM Mid-Atlantic Region's External Transactions: January through May 2003



Internal Bilateral Transactions

Internal, unit-specific transactions for the PJM Mid-Atlantic Region during the first interval of 2003 were about 66 percent higher than they had been in the same period of 2002. Internal capacity credit transactions in the first interval of 2003 were about 45 percent higher than they had been in the first interval of 2002.

Figure 4-6 The PJM Mid-Atlantic Region's Internal Bilateral Transactions: January through May 2003



Active Load Management Credits

Active load management (ALM) reflects the ability of individual customers, under contract with their LSE, to reduce specified amounts of load during an emergency declared in the PJM Mid-Atlantic Region. ALM credits, measured in MW of curtailable load, reduce LSE capacity obligations. ALM credits in the PJM Mid-Atlantic Region averaged 1,292 MW in the first interval of 2003, down approximately 34 percent from 1,963 MW in the first interval of 2002 (Table 4-2). ALM participation declined for a number of reasons, including the shifting of participants to other PJM demand-side response (DSR) programs.

PJM Western Region: January through May 2003

Supply Side

Structural analysis indicates that the PJM Western Region's Capacity Credit Markets exhibited extremely high levels of concentration in the first interval of 2003. HHI for the shorter term, Daily Capacity Credit Markets averaged about 9808 during the first interval of 2003, with a maximum of 9976 and a minimum of about 3196 (A single firm with 100 percent market share would result in an HHI of 10000 and two firms with equal market shares would result in an HHI of 5000). HHIs for the Interval, Monthly and Multimonthly Capacity Credit Markets were not calculated because there were no transactions in these markets during the first interval of 2003.[7] These results are consistent with the conclusion that there was no Capacity Market in the PJM Western Region.

Demand Side

During the first interval of 2003, electric utility companies supplied nearly 100 percent of the PJM Western Region's load obligations. Their market shares ranged from 99.95 percent to 99.98 percent and averaged 99.97 percent. The market share of unaffiliated companies was negligible, averaging 0.03 percent.

During the first interval of 2003, reliance on the PJM Western Region's Capacity Credit Markets was virtually nonexistent. All of the LSEs entered into bilateral contracts for their capacity during 2002. There was market activity on only three days during the interval. There was very little load served by LSEs other than the local electric utility.

Supply and Demand

Before June 2003, on average, capacity resources exceeded capacity obligations by 1,669 MW in the PJM Western Region (Table 4-3). Nonetheless, the PJM Western Region was capacity deficient on three days in the first interval of 2003 as the result of unit outages that affected the amount of available capacity resources under the PJM Western Region Capacity Market rules.

The amount of capacity resources in the PJM Western Region on any day reflects the addition of new resources and the retirement of old ones as well as the import or export of capacity resources, decisions that are a function of market forces. The total pool capacity obligation is set annually via an administrative process.

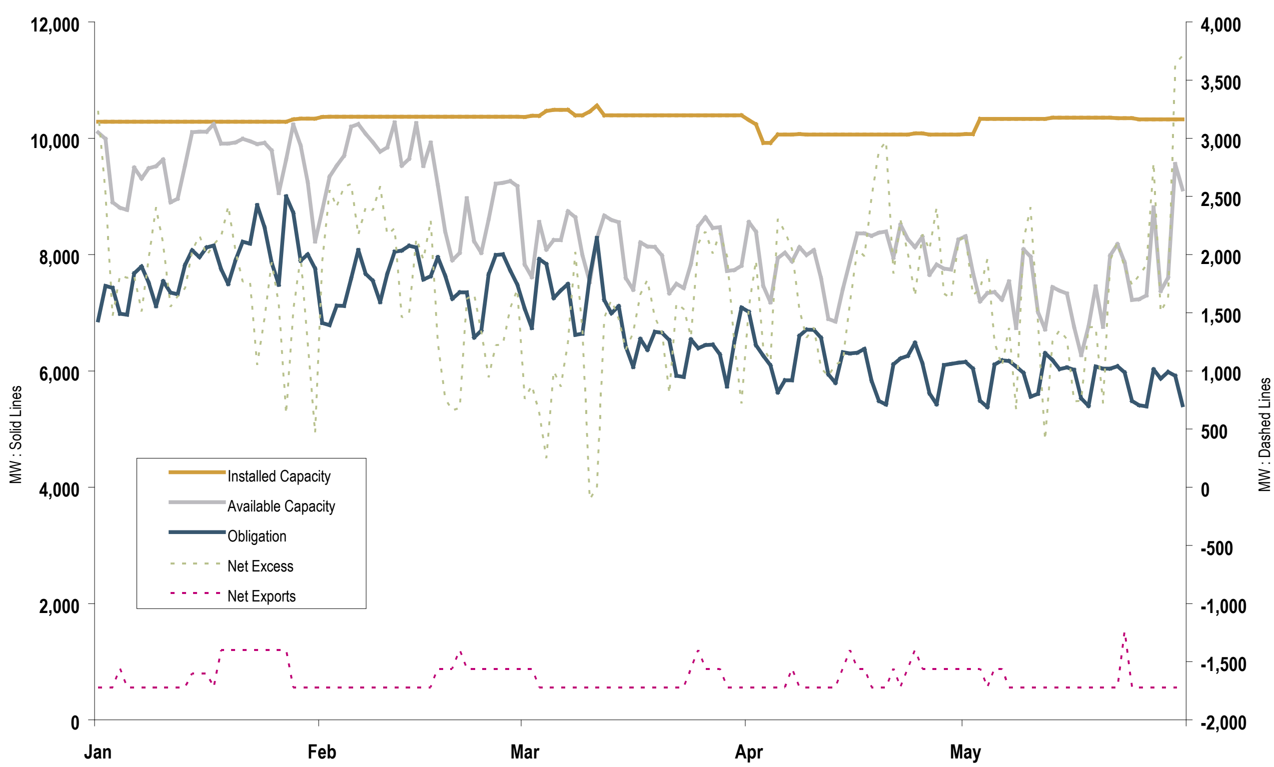
System net excess capacity can be determined by using available capacity (installed capacity adjusted for all current outages), obligation, the sum of members' excesses and the sum of their deficiencies. Table 4-3 presents these data for the first interval of 2003. Net excess is the net PJM Western Region position, calculated by subtracting system daily available capacity obligation (DACO) from total capacity resources. System DACO includes expected daily load plus 6 percent. Thus a net PJM Western Region position of zero is consistent with established reliability objectives.

7 See Section 2, "Energy Market," for a further discussion of HHI.

Table 4-3 The PJM Western Region's Member Capacity Summary: January through May 2003 (in MW)

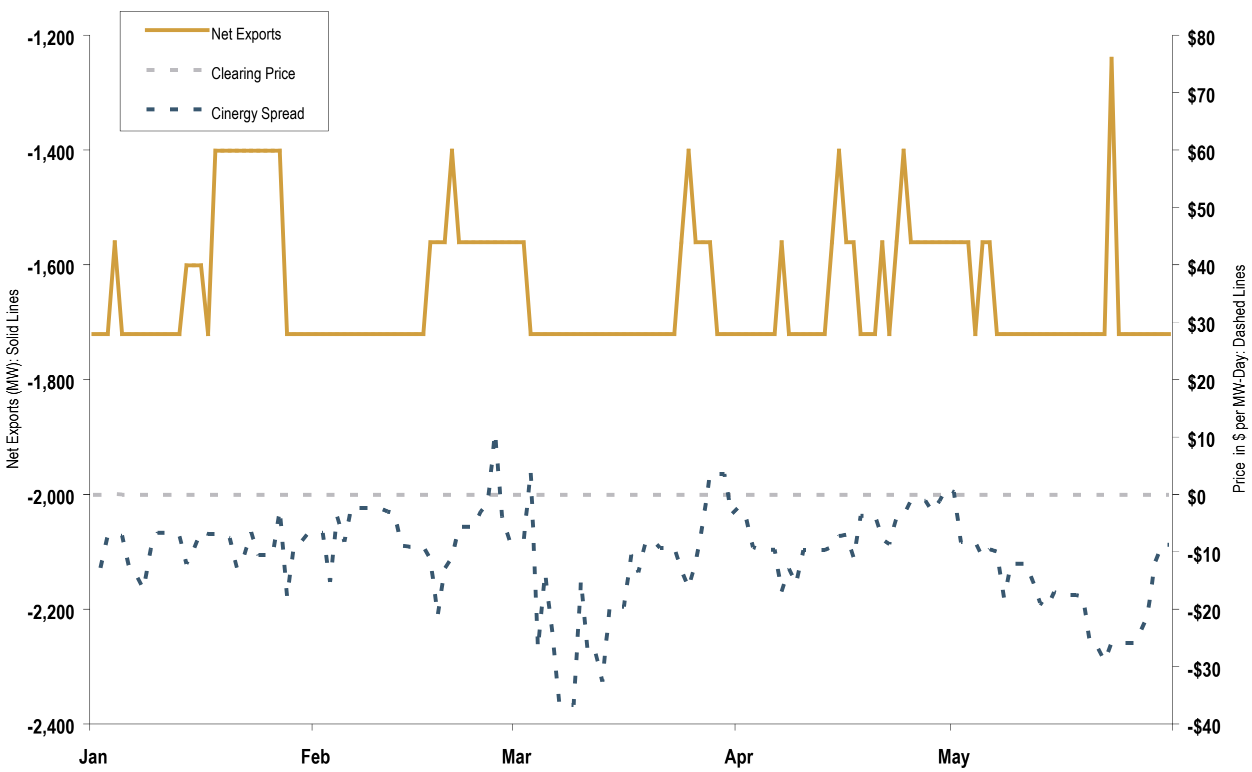
PJM Western Region	Mean	Standard Deviation	Minimum	Maximum	Change from 2002	Percent
Installed Capacity	10,293	128	9,919	10,561	-27	-0.3%
Available Capacity	8,482	996	6,271	10,274	946	12.6%
Obligation	6,817	889	5,377	9,002	819	13.7%
Sum of Excess	1,669	633	204	3,710	130	8.5%
Sum of Deficiency	4	31	0	309	3	259.0%
Net Excess	1,666	642	-102	3,710	127	8.3%
Imports	1,649	110	1,241	1,721	-40	-2.4%
Exports	0	0	0	0	-89	-100.0%
Net Exports	-1,649	110	-1,721	-1,241	-49	3.1%
Unit-Specific Transactions	2,290	256	1,577	2,633	1,832	400.4%
Capacity Credit Transactions	58	33	33	174	-106	-64.4%
Internal Bilateral Transactions	2,348	249	1,626	2,667	1,726	277.6%
Daily Capacity Credits	0	1	0	8	-7	-98.0%
Monthly Capacity Credits	0	0	0	0	-123	-100.0%
Multimonthly Capacity Credits	0	0	0	0	0	n/a
All Capacity Credits	0	1	0	8	-130	-99.8%
QIL Credits	0	0	0	0	0	n/a

Figure 4-7 The PJM Western Region's Capacity Obligations: January through May 2003



As shown in Table 4-3, imports of capacity resources for the first interval averaged about 1,650 MW. There were no exports from the PJM Western Region in the first interval of 2003. This is consistent with the fact that the external, daily forward energy prices were generally less than the PJM Western Region's prices. The PJM Western Region price in these graphs is the firm, daily forward on-peak PJM Western Hub energy price, while the external price is the firm, daily forward on-peak price for Cinergy.

Figure 4-8 The PJM Western Region's Capacity Credit Market Clearing Price and Cinergy Spread versus Its Net Exports: January through May 2003



External Capacity Transactions

The PJM Western Region's capacity resources may be traded bilaterally within and outside of the PJM Western Region. Table 4-3 presents the PJM Western Region bilateral capacity transaction data for the first interval of 2003. An average of 1,650 MW of capacity resources was imported into the PJM Western Region and an average of 0 MW was exported (delisted), for an average net import of 1,650 MW of capacity resources during the period. The maximum export (delist) was 0 MW, while the maximum import was 1,721 MW.

Internal Bilateral Transactions

Average internal transactions for the PJM Western Region during the first interval of 2003 were 2,348 MW. Internal unit-specific bilateral transactions accounted for approximately 97 percent of all internal bilateral transactions or 2,290 MW. Internal capacity credit transactions in the first interval of 2003 averaged approximately 58 MW.

PJM: June through December 2003

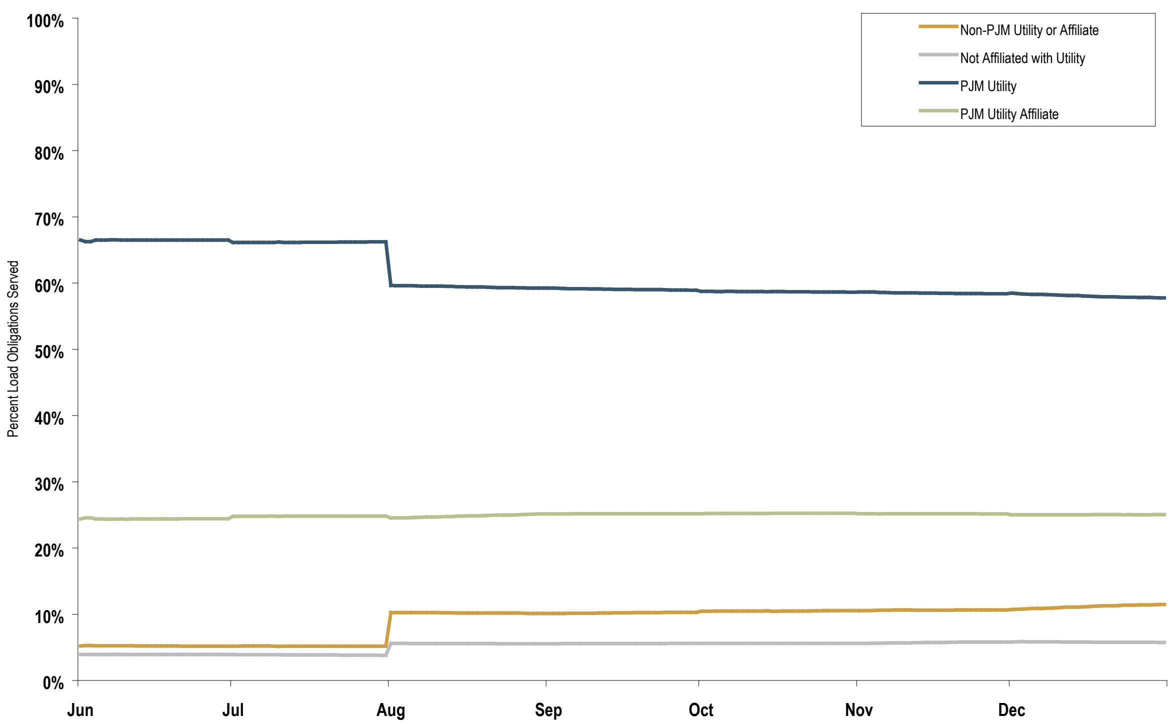
Supply Side

The MMU structural analysis indicates that overall, the PJM Capacity Credit Markets in the last two intervals of 2003 exhibited high levels of concentration. HHIs for the Daily Capacity Credit Markets averaged about 2155, with a maximum of about 3071 and a minimum of about 1262 (four firms with equal market shares would result in an HHI of 2500). HHI for the longer term Interval, Monthly and Multimonthly Capacity Credit Markets averaged about 2479, with a maximum of 6180 and a minimum of more than 1430 (three firms with equal market shares would result in an HHI of 3333). On average 1,120 MW were traded in the Daily Capacity Credit Markets and 3,620 MW were traded in the Monthly and Multimonthly Capacity Credit Markets. The total of 4,740 MW represented, on average, 6.8 percent of total load obligation for the period of which 1.6 percent was attributable to the Daily Capacity Credit Market and 5.2 percent was attributable to the Monthly and Multimonthly Capacity Credit Market.

Demand Side

The market share of non-PJM utilities or affiliates and LSEs not affiliated with a utility, increased on August 1, 2003 by 3,572 MW (5.1 percent) and 1,257 MW (1.8 percent), respectively. Correspondingly, the market share of PJM electric utility companies and their affiliates declined by 4,721 MW or 6.9 percent, averaging 86 percent of the total PJM load obligations during the final two intervals. The market share of PJM electric utility companies averaged 61 percent of the service area's load. Prior to August 1, 2003, PJM electric utility companies averaged 46,307 MW of load or 66.3 percent of load obligation; after August 1, 2003, their load share averaged 41,328 MW or 58.8 percent of load obligation. As Figure 4-9 shows, market share of the affiliates of PJM electric utilities averaged 25 percent. Their market share prior to August 1, 2003 averaged 17,152 MW or 24.6 percent of load obligation; after August 1, 2003, their market share averaged 17,627 MW or 25.1 percent. The market share of LSEs not affiliated with a utility averaged 3,610 MW was about 5 percent for the final two intervals. Prior to August 1, 2003, their share averaged 2,718 MW or 3.9 percent of load obligation; after August 1, 2003, their average share increased to 3,963 MW or 5.6 percent of load obligation. The market share of non-PJM utilities and their affiliates averaged 6,314 MW or 9 percent for the final two intervals. Prior to August 1, 2003, their share averaged 3,628 MW or 5.2 percent of load obligation; after August 1, 2003, their average share increased to 7,378 MW or 10.5 percent of load obligation.

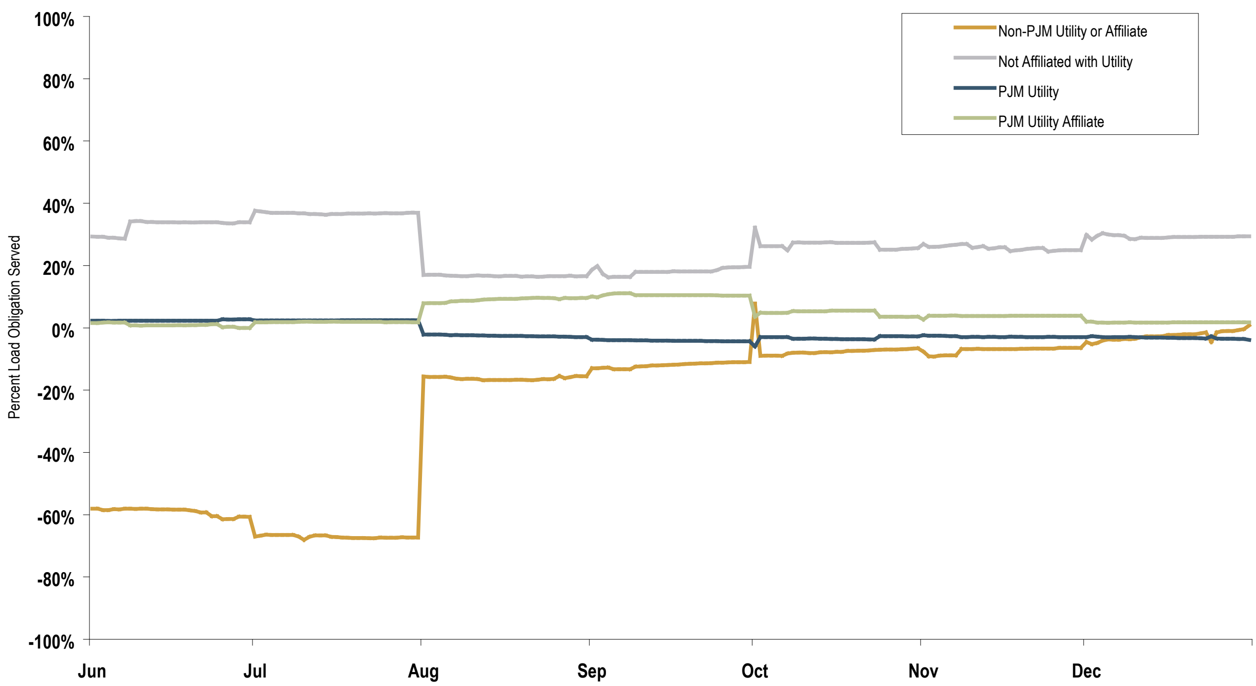
Figure 4-9 Percent of PJM Load Obligation Served: June through December 2003



During the final two intervals of 2003, reliance on the PJM Capacity Credit Markets varied by sector. As Figure 4-10 shows, PJM electric utilities relied on Capacity Credit Markets for an average of -1.6 percent of their 2003 unforced capacity obligation (they were net sellers) for the final two intervals while their affiliates relied on Capacity Credit Markets for an average of 4.7 percent of theirs. Affiliates of non-PJM electric utilities obtained an average of -24.5 percent of their unforced capacity obligations (they were net sellers) from the Capacity Credit Markets while unaffiliated LSEs obtained an average of 26.6 percent of their capacity obligations from the Capacity Credit Markets. The measure of Capacity Credit Market reliance is the sector's daily net Capacity Credit Market position divided by the sector's capacity obligation (This excludes self-supply and bilateral transactions). Thus, a negative share means that a sector has sold more capacity credits than it has purchased for a day.

During the final two intervals of 2003, the reliance of LSEs not affiliated with utilities on Capacity Credit Markets diminished from approximately 37 percent to about 16 percent in August 2003 and then increased again to average about 30 percent for the final interval. As Figure 4-9 and Figure 4-10 show, the load share gained by LSEs not affiliated with utilities was more than covered by bilateral transactions, reducing the reliance of these LSEs on the Capacity Credit Market. On August 1, 2003, the net sales in the Capacity Credit Markets declined by 51.8 percent for non-PJM utilities and their affiliates in part as the result of increased capacity obligations.

Figure 4-10 Percent of Load Obligation Served by PJM Capacity Credit Market: June through December 2003



Supply and Demand

In the final two intervals of 2003, capacity resources exceeded capacity obligations in PJM on every day. The pool was long by an average of 2,954 MW or about 4 percent of the average obligation. The amount of capacity resources in PJM on any day reflects the addition of new resources, the retirement of old ones and the importing or exporting of capacity resources, all decisions that are functions of market forces. The total pool capacity obligation is set annually via an administrative process.

System net excess capacity can be determined using unforced capacity, obligation, the sum of members' excesses and the sum of members' deficiencies. Table 4-4 presents these data for 2003.[8] Net excess is the net pool position, calculated by subtracting obligations from capacity resources. Since obligations include expected load plus a reserve margin, a net pool position of zero is consistent with established reliability objectives.

8 These data are posted on a monthly basis at www.pjm.com under the Market Monitoring Link.

Table 4-4 PJM Member Capacity Summary: June through December 2003 (in MW)

PJM	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	77,728	1,123	75,866	79,045
Unforced Capacity	73,152	1,061	71,485	74,401
Obligation	70,203	190	69,487	70,492
Sum of Excess	2,954	927	1,447	4,266
Sum of Deficiency	5	10	0	31
Net Excess	2,949	931	1,447	4,266
Imports	3,819	468	3,218	4,638
Exports	1,664	314	1,259	2,457
Net Exports	-2,155	686	-3,094	-761
Unit-Specific Transactions	59,311	199	59,011	59,674
Capacity Credit Transactions	71,649	948	70,079	72,937
Internal Bilateral Transactions	130,960	912	129,372	132,611
Daily Capacity Credits	1,120	468	429	2,872
Monthly Capacity Credits	746	168	458	955
Multimonthly Capacity Credits	2,874	602	1,950	3,484
All Capacity Credits	4,740	346	4,420	5,942
ALM Credits	1,207	36	1,156	1,256

Figure 4-11 PJM Capacity Obligations: June through December 2003

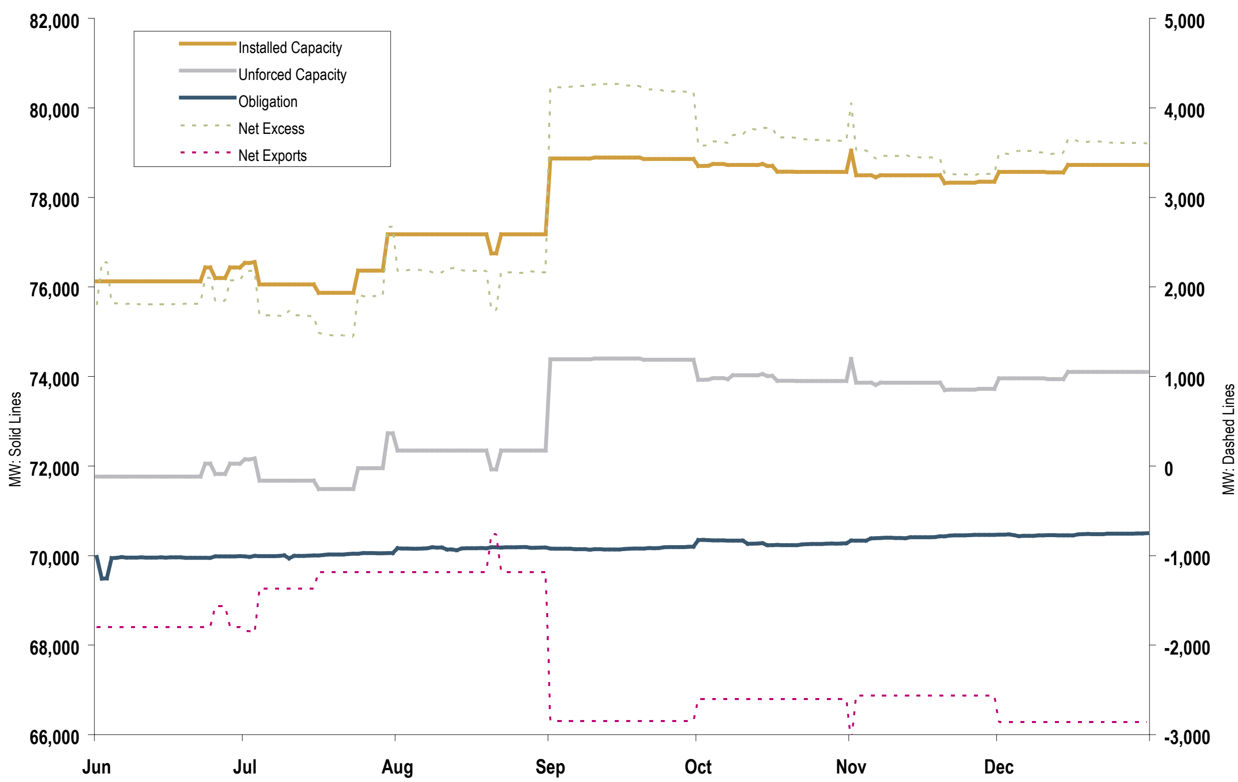
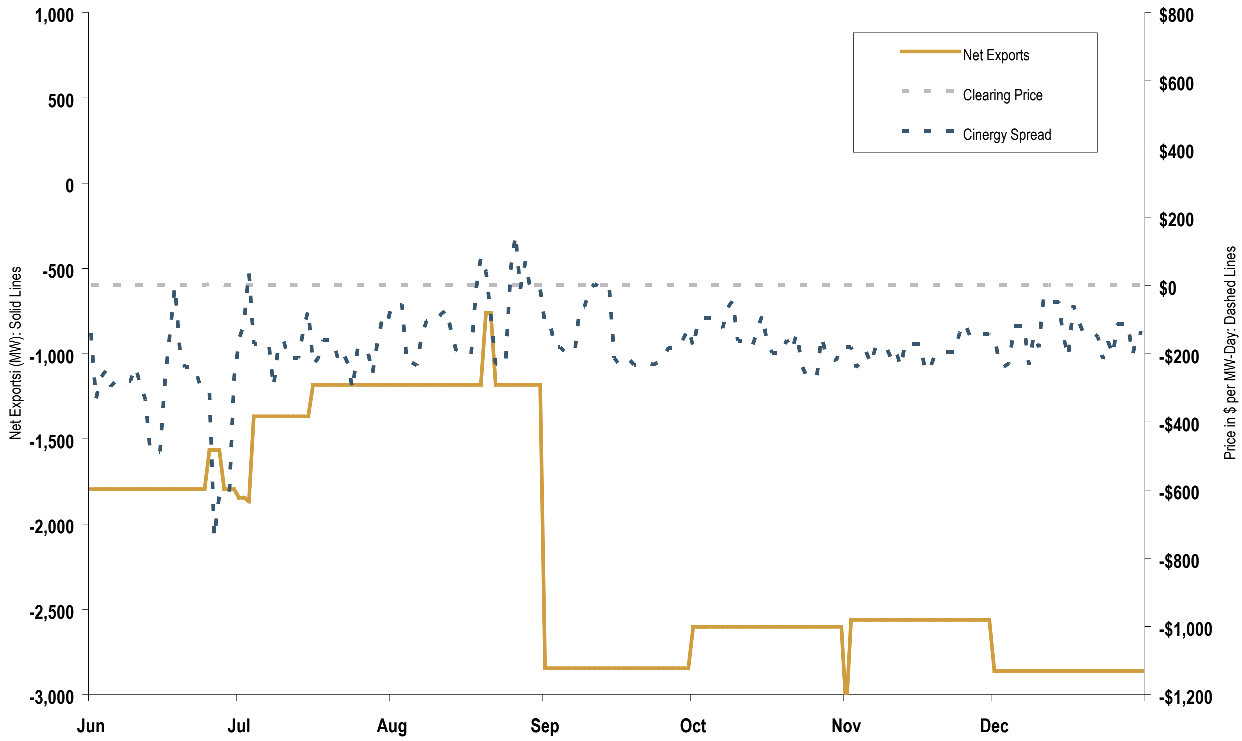


Figure 4-12 PJM Daily Capacity Credit Market Clearing Price and Cinergy Spread versus Its Net Exports: June through December 2003



As shown in Figure 4-12 and Figure 4-13, capacity owners increased external sales of capacity resources for the summer period even though the external daily forward energy prices were generally less than PJM systemwide prices. The PJM price in these graphs is the firm, daily forward on-peak PJM Western Hub energy price, while the external price is the firm, daily forward on-peak price for Cinergy.[9]

Capacity Transactions

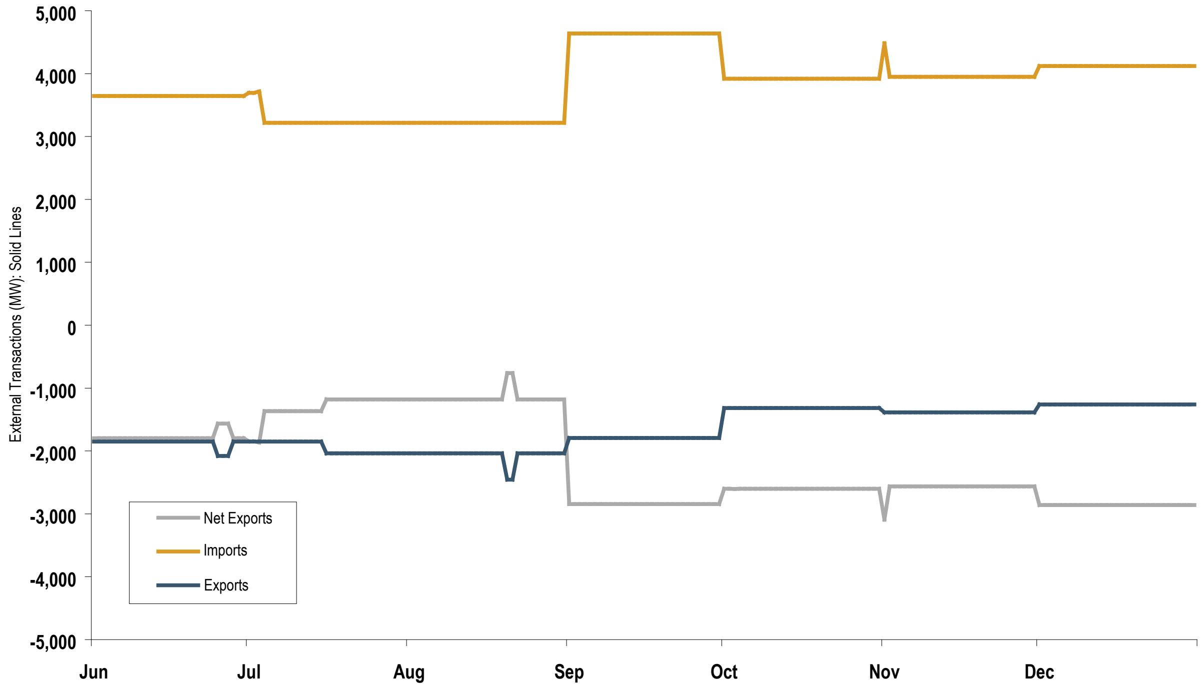
PJM capacity resources may be traded bilaterally within and outside of the service area. Table 4-4 and Figure 4-14 present PJM bilateral capacity transaction data for the final two intervals of 2003. External bilateral sales (delists) or external bilateral purchases of capacity resources may only be unit-specific; internal bilateral transactions may be unit-specific or in the form of capacity credits.

External Bilateral Transactions

An average of 3,819 MW of capacity resources was imported into the PJM and an average of 1,664 MW was exported (delisted) for an average net import of 2,155 MW of capacity resources during the period. The maximum export (delist) was 2,457 MW, while the maximum import was 4,638 MW. About three quarters of the capacity exports (1,200 MW in the summer interval) during this period went to New York in response to the NYISO's implementation of a demand curve for capacity.

9 These daily forward prices are on-peak prices.

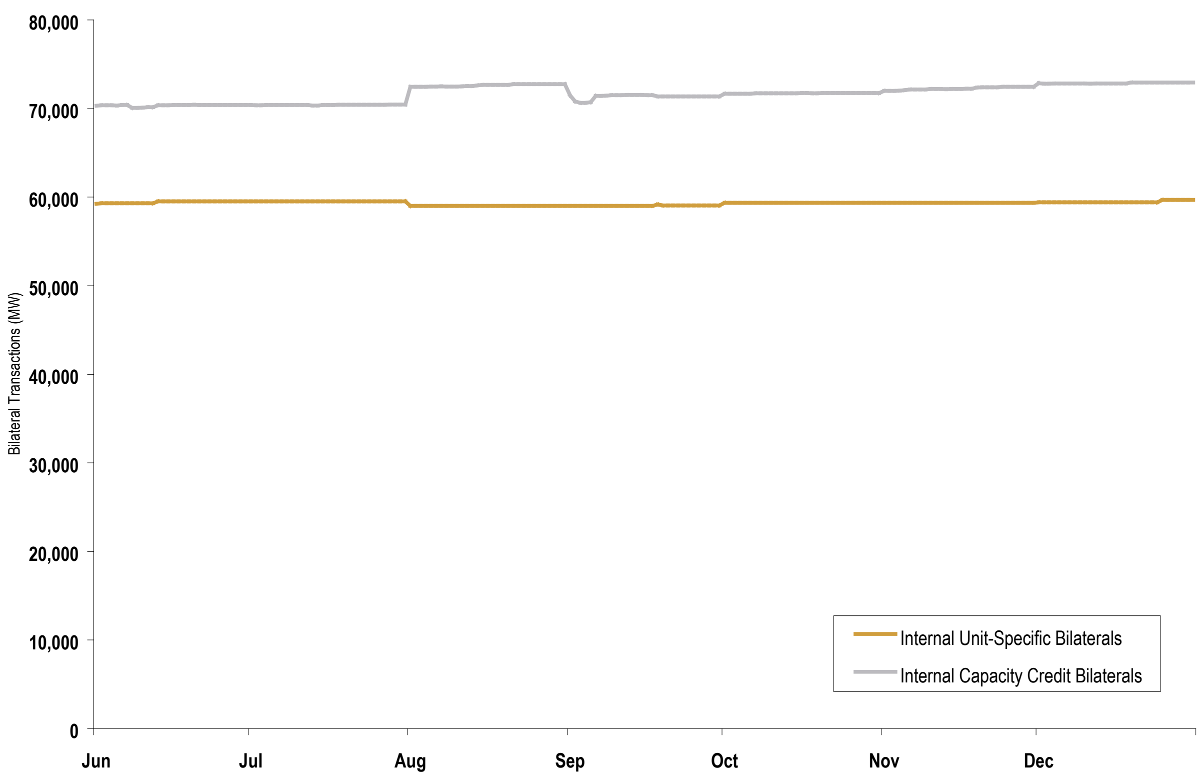
Figure 4-13 PJM External Transactions: June through December 2003



Internal Bilateral Transactions

Internal, unit-specific transactions in the final two intervals of 2003 averaged 59,311 MW per day. Since bilateral contracts of any type can be traded for any period and multiple times, the amount of MW traded can be more than the load obligation. Internal capacity credit transactions during the final two intervals of 2003 averaged 71,649 MW per day. As Figure 4-14 shows, bilateral transactions remained nearly flat for the final two intervals of 2003.

Figure 4-14 PJM Internal Bilateral Transactions: June through December 2003



Active Load Management Credits

ALM reflects the ability of individual customers, under contract with their LSE, to reduce specified amounts of load during an emergency declared within the PJM system. ALM credits, measured in MW of curtailable load, reduce LSE capacity obligations. ALM credits in PJM averaged 1,207 MW in the June to December 2003 intervals (Table 4-4). ALM participation in the last two intervals of 2003 declined by 85 MW or nearly 7 percent compared to the year's first interval because participants shifted to competing PJM DSR programs.

Market Performance

PJM Mid-Atlantic Region: January through May 2003

Capacity Credit Markets

PJM operated Daily, Monthly and Multimonthly Capacity Credit Markets for the Mid-Atlantic Region from January through May 2003. As Table 4-2 shows, the Daily Capacity Credit Market averaged 602 MW of transactions, or about 1.0 percent of the average capacity obligations for the period. Trading in the PJM Mid-Atlantic Region's Daily Capacity Credit Markets increased slightly compared to activity in the market in 2002.

Prices

Table 4-5 shows prices and volumes in both the Daily and the longer term Capacity Credit Markets. The volume-weighted average price for the first interval of 2003 was $17.36 per MW-day in the Monthly and Multimonthly Capacity Credit Markets and was $6.00 per MW-day in the Daily Capacity Credit Markets. The volume-weighted average price for all Capacity Credit Markets was $15.55 per MW-day.[10] Prices in the Daily Capacity Credit Market were relatively constant during the first interval of the year and declined in the Interval, Monthly and Multimonthly Capacity Credit Markets (Figure 4-15). Prices in the monthly and multimonthly markets in 2003 were significantly lower than in 2002; however, prices in the Daily Capacity Credit Markets were slightly higher. The volume-weighted average of all Capacity Credit Markets was $52.86 per MW-day in 1999, $60.55 in 2000, $95.34 in 2001 and $33.40 in 2002. Prices in the Monthly and Multimonthly Capacity Credit Markets were $70.66 per MW-day in 1999, $53.16 in 2000, $100.43 in 2001 and $38.21 in 2002, while the Daily Capacity Credit Market price averaged $3.63 per MW-day in 1999, $69.39 in 2000, $87.98 in 2001 and $0.59 in 2002.

10 Data in the graph and the average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced

Figure 4-15 The PJM Mid-Atlantic Region's Daily and Monthly Capacity Credit Market Performance: January through May 2003

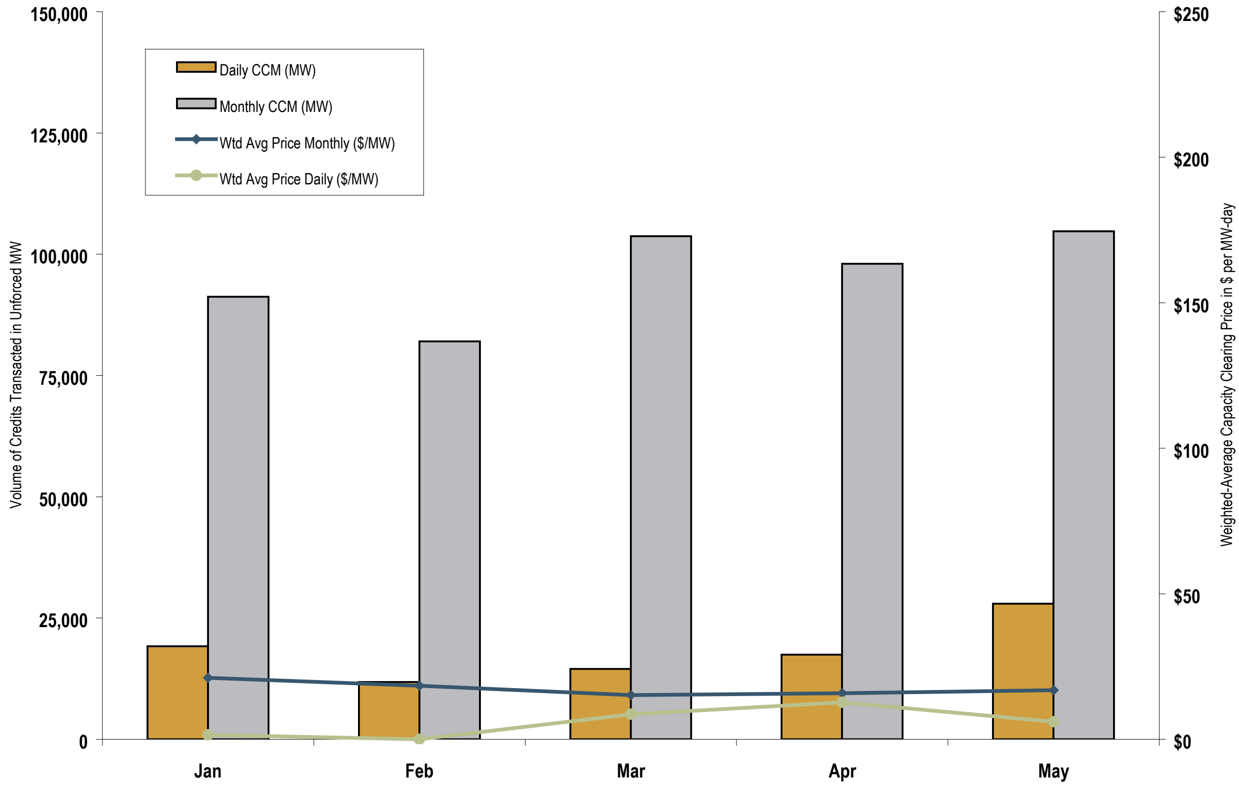


Table 4-5 The PJM Mid-Atlantic Region's Capacity Credit Market: January through May 2003

Month/Year	Daily (MW)	Monthly and Multimonthly (MW)	Combined (MW)	Weighted-Average Price Daily ($ per MW)	Weighted-Average Price Monthly and Multimonthly ($ per MW)	Weighted-Average Price Combined ($ per MW)
Dec-03	n/a	n/a	n/a	n/a	n/a	n/a
Nov-03	n/a	n/a	n/a	n/a	n/a	n/a
Oct-03	n/a	n/a	n/a	n/a	n/a	n/a
Sep-03	n/a	n/a	n/a	n/a	n/a	n/a
Aug-03	n/a	n/a	n/a	n/a	n/a	n/a
Jul-03	n/a	n/a	n/a	n/a	n/a	n/a
Jun-03	n/a	n/a	n/a	n/a	n/a	n/a
May-03	27,965	104,727	132,693	6.03	16.87	14.58
Apr-03	17,462	98,025	115,487	12.66	15.81	15.33
Mar-03	14,518	103,707	118,225	8.62	15.22	14.41
Feb-03	11,798	82,020	93,818	0.03	18.38	16.07
Jan-03	19,197	91,261	110,458	1.56	21.14	17.73
Jan-May 2003	90,940	479,741	570,681	6.00	17.36	15.55

PJM Western Region: January through May 2003

PJM operated Daily, Monthly and Multimonthly Capacity Credit Markets in its Western Region during the first interval of 2003. Consistent with the small share of the market served by nonaffiliated LSEs, the Daily Capacity Credit Market averaged 0.15 MW of transactions, or about 0.04 percent of the average capacity obligations for the period (Table 4-6).[11]

Capacity Credit Market Pricing

Table 4-6 and Figure 4-16 show prices and volumes through May 31, 2003, in both the Daily and the longer term Capacity Credit Markets. The volume-weighted average prices for the period were $74.44 per MW-day in the Monthly and Multimonthly Capacity Credit Markets and $0.02 per MW-day in the Daily Capacity Credit Market. The volume-weighted average of all Capacity Credit Markets was $29.44 per MW-day.[12] The high prices in the monthly and multimonthly markets were a result of multimonthly deals done in 2002.

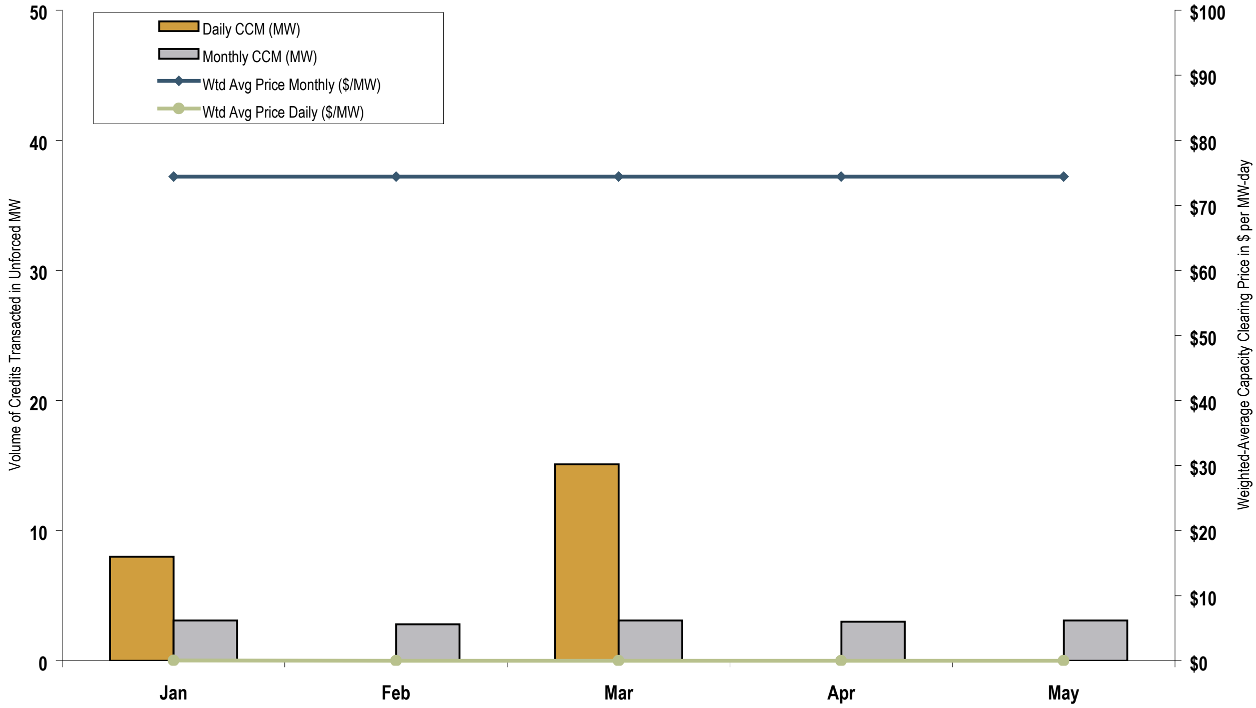
Table 4-6 The PJM Western Region's Capacity Credit Market: January through May 2003

Month/Year	Dail (MW)	Monthly and Multimonthly (MW)	Combined (MW)	Weighted-Average Price Daily ($ per MW)	Weighted-Average Price Monthly and Multimonthly ($ per MW)	Weighted-Average Price Combined ($ per MW)
Dec-03	n/a	n/a	n/a	n/a	n/a	n/a
Nov-03	n/a	n/a	n/a	n/a	n/a	n/a
Oct-03	n/a	n/a	n/a	n/a	n/a	n/a
Sep-03	n/a	n/a	n/a	n/a	n/a	n/a
Aug-03	n/a	n/a	n/a	n/a	n/a	n/a
Jul-03	n/a	n/a	n/a	n/a	n/a	n/a
Jun-03	n/a	n/a	n/a	n/a	n/a	n/a
May-03	0	3	3	0.00	74.44	74.44
Apr-03	0	3	3	0.00	74.44	74.44
Mar-03	15	3	18	0.00	74.44	12.68
Feb-03	0	3	3	0.00	74.44	74.44
Jan-03	8	3	11	0.05	74.44	20.83
Jan-May 2003	23	15	38	0.02	74.44	29.44

11 Only limited data are provided for the PJM Western Region's Capacity Market because the additional data would provide confidential information about the dominant participant in that market.

12 Data in the graph and the average price data are all in terms of available capacity. Capacity credits are, by definition, in terms of available capacity.

Figure 4-16 The PJM Western Region's Daily and Monthly Capacity Credit Market Performance: January through May 2003



The performance of the PJM Western Region's Capacity Markets illustrates that these were not markets in any meaningful sense. The Capacity Market was dominated on the supply side by one participant and there was very little activity on the demand side.

PJM: June through December 2003

Capacity Credit Markets

PJM operated combined Daily, Monthly and Multimonthly Capacity Credit Markets for the final two intervals of 2003. As Table 4-4 shows, the Daily Capacity Credit Market averaged 1,120 MW of transactions, or about 1.6 percent of the average capacity obligations for the period.

Prices

Table 4-7 shows prices and volumes in both the Daily and the longer term PJM Capacity Credit Markets. The volume-weighted average price for the final two intervals of 2003 was $24.18 per MW-day in the Monthly and Multimonthly Capacity Credit Markets and $0.68 per MW-day in the Daily Capacity Credit Markets. The volume-weighted average price for all Capacity Credit Markets was $18.61 per MW-day.[13] Prices in the Daily Capacity Credit Market were relatively constant during the year and declined in the monthly and multimonthly markets (Figure 4-17). Prices in the Capacity Credit Markets in 2003 were lower overall than in 2002.

13 Data in the graph and the average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.

Figure 4-17 PJM Daily and Monthly Capacity Credit Market Performance: June through December 2003

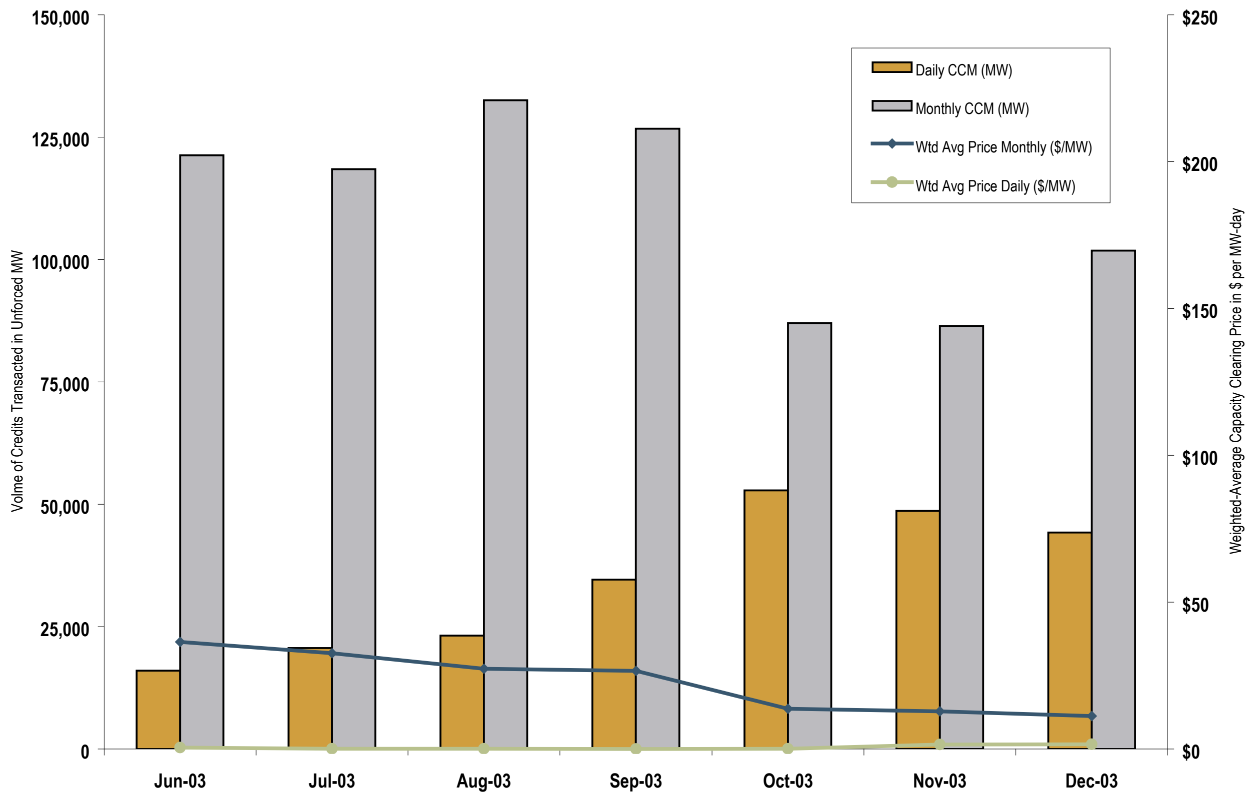


Table 4-7 PJM Capacity Credit Market: June through December 2003

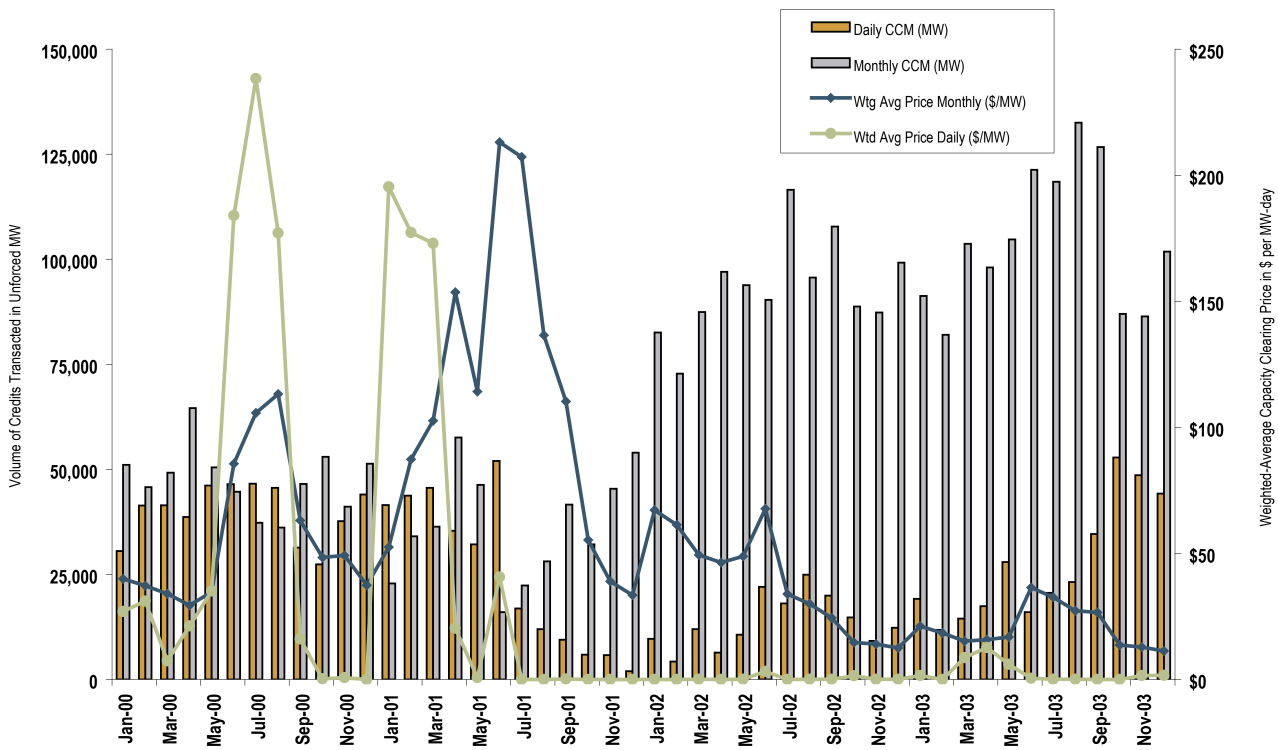
Month/Year	Daily (MW)	Monthly and Multimonthly (MW)	Combined (MW)	Weighted-Average Price Daily ($ per MW)	Weighted-Average Price Monthly and Multimonthly ($ per MW)	Weighted-Average Price Combined ($ per MW)
Dec-03	44,240	101,847	146,088	1.63	11.26	8.34
Nov-03	48,638	86,421	135,059	1.55	12.86	8.79
Oct-03	52,844	87,023	139,867	0.04	13.68	8.53
Sep-03	34,596	126,726	161,322	0.02	26.58	20.88
Aug-03	23,164	132,525	155,689	0.05	27.29	23.23
Jul-03	20,632	118,439	139,070	0.11	32.62	27.80
Jun-03	16,020	121,311	137,331	0.50	36.46	32.27
May-03	n/a	n/a	n/a	n/a	n/a	n/a
Apr-03	n/a	n/a	n/a	n/a	n/a	n/a
Mar-03	n/a	n/a	n/a	n/a	n/a	n/a
Feb-03	n/a	n/a	n/a	n/a	n/a	n/a
Jan-03	n/a	n/a	n/a	n/a	n/a	n/a
Jun-Dec 2003	240,133	774,292	1,014,426	0.68	24.18	18.61

PJM: January 2000 through December 2003

Capacity Credit Markets

Figure 4-18 shows prices and volumes in both the Daily and the longer term PJM Capacity Credit Markets from 1999 through 2003. Since the interval system was introduced in June 2001, overall volume in the Monthly and Multimonthly Capacity Credit Markets has increased and prices in both the daily and longer term markets have remained stable. Although daily volume has risen to pre-June 2001 levels, capacity obligations have increased by more than 25 percent. The share of load obligation traded in PJM Daily capacity markets has declined since the introduction of interval markets, 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 1.6 percent in the last two intervals of 2003. Monthly and Multimonthly Capacity Market volume increased from 3.0 percent of obligation in 2000 to 5.2 percent of average obligation in the last two intervals of 2003.

Figure 4-18 PJM Daily and Monthly Capacity Credit Market Performance: January 2000 through December 2003



PJM: January 2003 through December 2003

Capacity Credit Market Prices

Table 4-8 shows prices and volumes in both the Daily and the longer term PJM Capacity Credit Markets for the year 2003 combining both the PJM Mid-Atlantic Region from January through May and for PJM from June through December. The volume-weighted average price for 2003 was $21.57 per MW-day in the Monthly and Multimonthly Capacity Credit Markets and $2.14 per MW-day in the Daily Capacity Credit Markets. The volume-weighted average price for all Capacity Credit Markets was $17.51 per MW-day.[14] Prices in the Daily Capacity Credit Market were relatively constant during the year and declined in the monthly and multimonthly markets (shown in the last twelve months of Figure 4-18). Prices in the Capacity Credit Markets in 2003 were lower overall than in 2002.

14 Data in the graph and the average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.

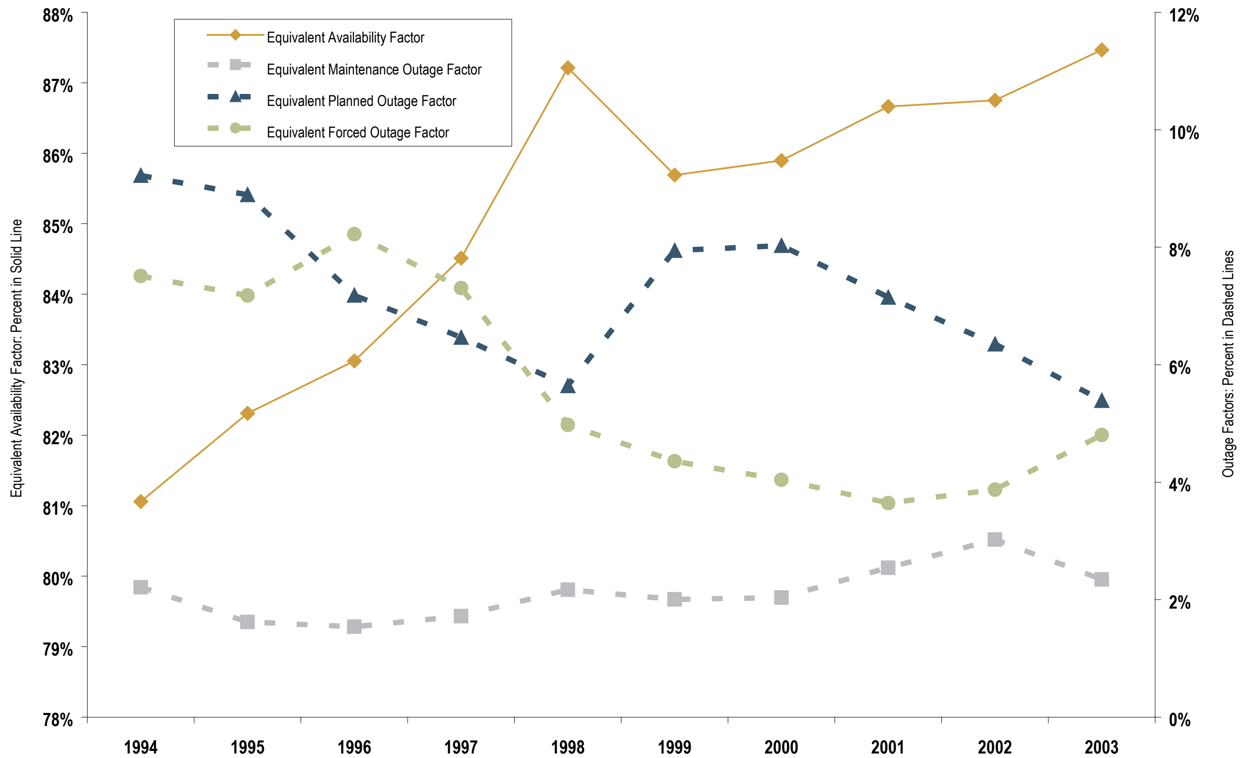
Table 4-8 PJM Capacity Credit Market: January through December 2003

Month/Year	Daily (MW)	Monthly and Multimonthly (MW)	Combined (MW)	Weighted-Average Price Daily ($ per MW)	Weighted-Average Price Monthly and Multimonthly ($ per MW)	Weighted-Average Price Combined ($ per MW)
Jan-03	19,197	91,261	110,458	1.56	21.14	17.73
Feb-03	11,798	82,020	93,818	0.03	18.38	16.07
Mar-03	14,518	103,707	118,225	8.62	15.22	14.41
Apr-03	17,462	98,025	115,487	12.66	15.81	15.33
May-03	27,965	104,727	132,693	6.03	16.87	14.58
Jun-03	16,020	121,311	137,331	0.50	36.46	32.27
Jul-03	20,632	118,439	139,070	0.11	32.62	27.80
Aug-03	23,164	132,525	155,689	0.05	27.29	23.23
Sep-03	34,596	126,726	161,322	0.02	26.58	20.88
Oct-03	52,844	87,023	139,867	0.04	13.68	8.53
Nov-03	48,638	86,421	135,059	1.55	12.86	8.79
Dec-03	44,240	101,847	146,088	1.63	11.26	8.34
Jan-Dec 2003	331,073	1,254,033	1,585,106	2.14	21.57	17.51

Availability

Certain outage statistics are calculated by reference to total hours in the year rather than statistical probability. Figure 4-19 shows these performance measures for all PJM units including the PJM Mid-Atlantic Region and the PJM Western Region. The equivalent availability factor equals the proportion of hours in a year that a unit was available to generate at full capacity. The sum of the equivalent availability factor, the equivalent maintenance outage factor, the equivalent planned outage factor and equivalent forced outage factor equals 100 percent. The increase in the equivalent forced outage factor and the equivalent availability factors from 2002 to 2003 corresponded with a decrease in the equivalent planned outage and the equivalent maintenance outage factors. The PJM aggregate equivalent availability factor was 86.8 percent in 2002 and 87.5 percent in 2003.

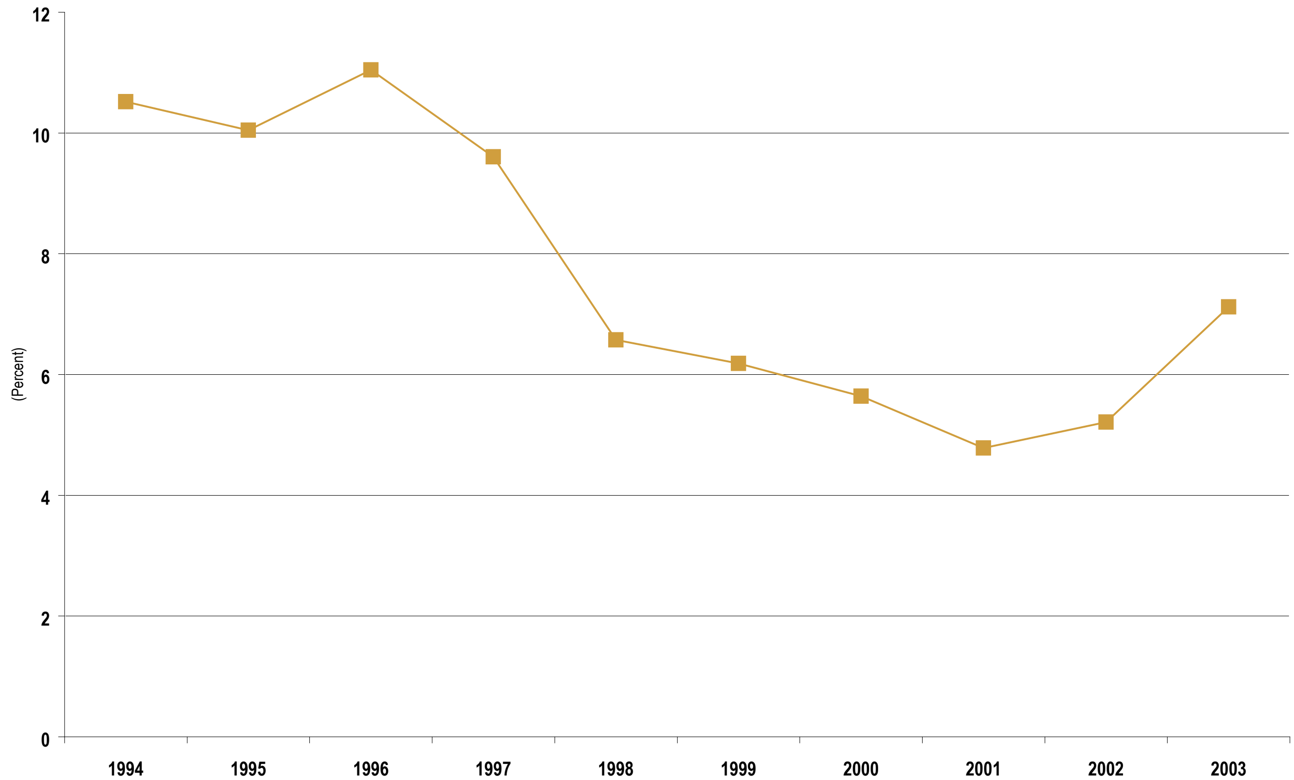
Figure 4-19 PJM Equivalent Outage and Availability Factors: 1994 through 2003



Unforced capacity from a specific unit is based on both the maximum summer capability of the unit and the forced outage rate. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available from a unit is inversely related to the forced outage rate. The equivalent demand forced outage rate (EFORd) is a statistical measure of the probability that a unit will fail, either partially or totally, to perform when it is needed. The EFORd calculation uses historical data including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours. Between 1996 and 2001, the average PJM[15] EFORd trended downward, reaching 4.8 percent in 2001 and then increased to 5.2 percent in 2002 and 7.1 percent in 2003. The increase in EFORd of 1.9 percent from 2002 to 2003 was the result of increased forced outage rates across all unit types. Fossil steam units' EFORd contributed 0.6 percentage points, combustion turbine units' EFORd contributed 0.9 percentage points and combined-cycle units' EFORd contributed 0.3 percentage points to the overall increase of 1.9 percentage points. Of the 659 generating units in the EFORd analysis, 134 units (about 20 percent) had increased EFORds. In the absence of offsetting improvements in EFORd by 62 units, the EFORd would have increased by 3.4 percentage points to 8.6 percent. The 62 units with lower forced outage rates reduced the EFORd by 1.5 percentage points, to the observed 7.1 percent EFORd. Figure 4-20 shows the average EFORd since 1994 for all units in the PJM Mid-Atlantic Region and PJM Western Region.

15 The 2003 PJM availability factors and forced outage rates are calculated for the PJM Western Region and the PJM Mid-Atlantic Region combined. The Equivalent Outage and Availability Factors figure and the EFORd figure are not directly comparable to the corresponding figures in the "2002 State of the Market Report" as the 2002 figures did not include generating units from the PJM Western Region.

Figure 4-20 PJM Equivalent Demand Forced Outage Rate (EFORd) Trend: 1994 through 2003



Section 5 – Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888.[1] Of these, PJM currently provides both regulation and spinning through market-based mechanisms.

Regulation matches generation with very short-term increases and decreases in load by moving the output of selected generators up and down via an automatic control signal. 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 and must be synchronized to the system and capable of providing output within 10 minutes.

The Regulation Market was introduced on June 1, 2000, and modified on December 1, 2002, at the same time the Spinning Reserve Market was implemented. Both the Regulation Market and the Spinning Reserve Market are cleared on a real-time basis.

Overview

The PJM Market Monitoring Unit (MMU) has reviewed structure and performance indicators for both the Regulation Market and the Spinning Reserve Market. The MMU concludes that both markets functioned effectively and produced competitive results in 2003.

Both the Regulation Market and the Spinning Reserve Market operate separately in the PJM Mid-Atlantic Region and in the PJM Western Region.[2] The market analysis treats each Regulation Market and each Spinning Reserve Market separately. Both the Regulation Market and the Spinning Reserve Market in the PJM Western Region are cost-based and are not competitive markets as there is only one supplier of regulation and one supplier of spinning reserve in the PJM Western Region. The Regulation Market and the Spinning Reserve Market in the PJM Mid-Atlantic Region are both based on a market-clearing price. All suppliers are paid the market price which is determined by demand and the offer of the marginal supplier. In the PJM Western Region, regulation and spinning reserve are compensated based directly on the costs of the specific units offering to provide the respective ancillary services, including opportunity costs.

Regulation Market Structure

- **Concentration of Ownership**. In 2003, the PJM Regulation Market saw an increase in concentration levels, although they generally remained moderate and concerns about market concentration continued to be offset by the level of available regulation supply relative to demand for the service. In the PJM Western Region, there was only one supplier.

Regulation Market Performance

- **Price.** The market price of regulation exhibited the expected relationship to changes in demand and the cost of supply. Average price per MW associated with meeting PJM's demand for regulation during 2003 increased by about $5 per MW, or about 14 percent over 2002. The average cost per MW in the PJM Mid-Atlantic Region was about $45 per MW, and the average cost per MW in the PJM Western Region was about $25 per MW.

1 See FERC "Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," April 24, 1996.

2 The PJM Mid-Atlantic Region is in the MAAC NERC region and the PJM Western Region is in the ECAR NERC region. MAAC and ECAR have different reliability requirements for the two services. These requirements are documented in the business rules for each market, located in the "PJM Manual for Scheduling Operations, M-11."

- **Availability.** Introduction of a market in regulation resulted in significant improvement in system regulation performance during 2001 and the first part of 2002. System regulation performance declined after the addition of the PJM Western Region in April 2002. However, system regulation performance was stable from December 2002 through December 2003 after the implementation of the new Regulation Market.

Spinning Reserve Market Structure

- **Concentration of Ownership.** In 2003, concentration was high in the Tier 2 Spinning Reserve Market. The average HHI for the PJM Mid-Atlantic Region in 2003 was 2544. In the PJM Western Region there was only one supplier.

Spinning Reserve Market Performance

- **Price.** Average cost per MW associated with meeting PJM's system demand for spinning reserve decreased about $6 per MW, or about 29 percent, in 2003 over 2002. Average cost per MW in the PJM Mid-Atlantic Region was about $15 per MW, and the average cost per MW in the PJM Western Region was about $43 per MW.

Regulation

Regulation Market Structure

In the PJM Mid-Atlantic Region in 2003, 590 generating units provided 64,514 MW of generating capacity, but 113 units were qualified to produce about 2,011 MW of regulation capability. By comparison, in the PJM Western Region in 2003, 69 generating units provided 11,119 MW of aggregate generating capacity, and 20 units were qualified to produce over 260 MW of regulation. Specific requirements for the service are established for each region.

The PJM Mid-Atlantic Region has different, areawide regulation requirements for on-peak hours (hours ending 0600 to 2400 hours) and off-peak hours (hours ending 0100 to 0500 hours).[3] 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.[4] During 2003, requirements ranged from approximately 750 MW of regulation capability for the peak period to approximately 220 MW for the off-peak period.

In the PJM Western Region, the regulation requirement is 1.0 percent of the peak forecast load and does not vary between on-peak and off-peak periods. During 2003, the requirement ranged from about 50 MW to over 84 MW.
In an affidavit filed with the FERC in 2000, the MMU recommended that PJM be permitted to implement a Regulation Market, based, in part, on a traditional measure of market structure, a concentration ratio, as measured by the HHI.[5] Concentration ratios measure the concentration of ownership in a market, in this case the ownership of regulation assets. An analysis of HHIs since the introduction of the Regulation Market indicates that seasonal HHIs have ranged between 1575 and 1845 (Table 5-1).[6] In 2003, the first full year of the new Regulation Market, HHIs were between 1751 and 1845.

3 On-peak and off-peak hours are defined differently for the Regulation Market than for the PJM Energy Market.
4 "PJM Manual for Scheduling Operations, Manual M-11," page 3-4.
5 FERC Docket No. ER00-1630, Affidavit of Joseph E. Bowring, February 2000.
6 See Section 2, "Energy Market," for a discussion of the HHI.

Table 5-1 PJM System Regulation Market HHI Values

Year	Season	HHI
2003	Winter	1751
2003	Fall	1845
2003	Summer	1763
2003	Spring	1788
2002	Winter	1601
2002	Fall	1575
2002	Summer	1599
2002	Spring	1587
2001	Winter	1711
2001	Fall	1689
2001	Summer	1703
2001	Spring	1715
2000	Winter	1763
2000	Fall	1747
2000	Summer	1735

HHI levels experienced thus far in the PJM Mid-Atlantic Region Regulation Market are, with the exception of the Fall 2003 period, categorized as "moderately concentrated" under the 1992 joint Department of Justice/Federal Trade Commission "Horizontal Merger Guidelines" and the FERC "Merger Policy Statement." A moderately concentrated market is one with an HHI between 1000 and 1800. The fact that several entities have large shares of the available supply of regulation is also a cause for concern. These concerns are moderated by the fact that the supply of regulation, at a maximum, is about 4.5 times the demand for it, and at a minimum, about 1.8 times the demand. Figure 5-1 and Figure 5-2 show the relationship between regulation supply and demand for PJM as a whole and for the PJM Western Region, respectively. In 2002, 123 units offered 2,222 MW of regulation capability into the PJM Mid-Atlantic Region Regulation Market and 21 units offered 260 MW of regulation capability into the PJM Western Region Regulation Market, for a total of 143 units. In 2003, 113 units offered 2,011 MW into the PJM Mid-Atlantic Region Regulation Market and 20 units offered 260 MW into the PJM Western Region Regulation Market. The average daily offer price in 2003 was about $17.27, a 32 percent decline from the average daily offer price of $22.54 in 2002.

The increased fluctuation of supply after the introduction of the new Regulation Market in December 2002 reflects changes in Regulation Market structure. The new market is an hour-ahead market; the previous market had been a day-ahead one. While suppliers still submit a day-ahead offer, they have the option to adjust this number hourly. The result has been more changes in hourly available regulation.

Figure 5-1 PJM System Regulation MW Offered versus MW Purchased

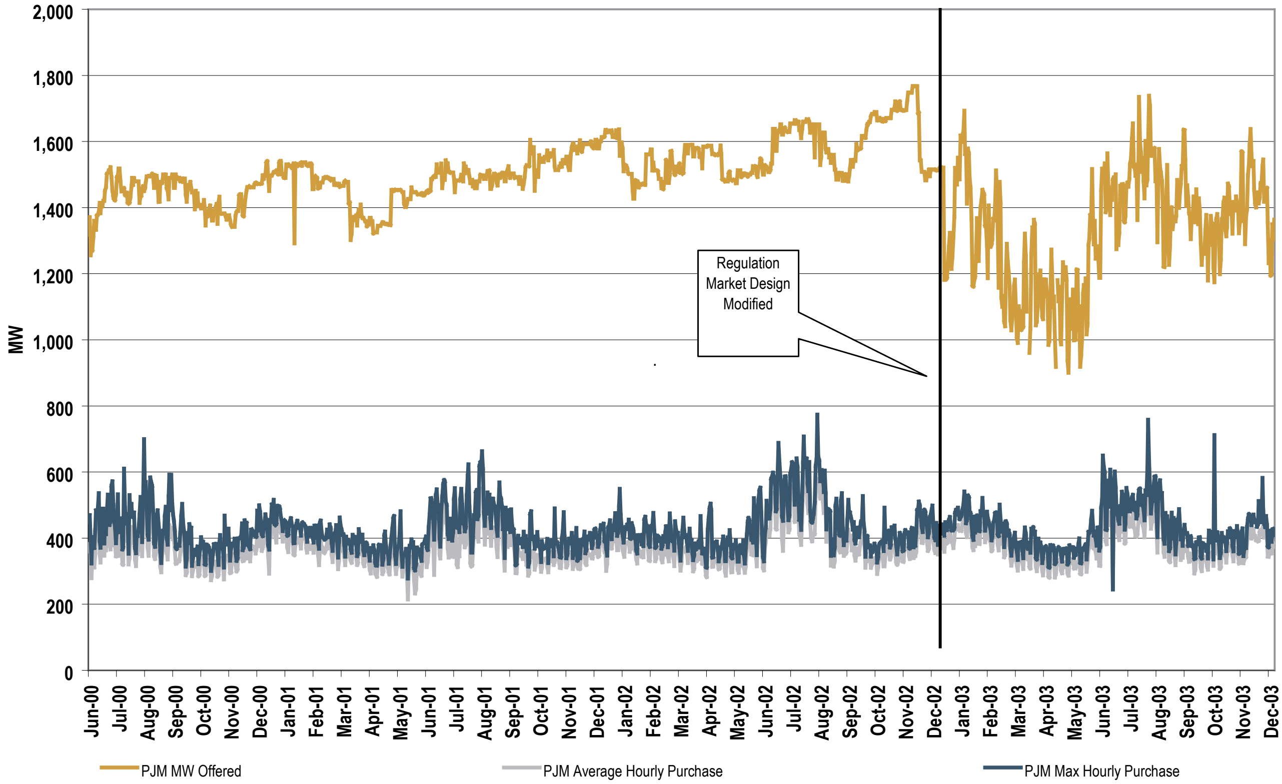
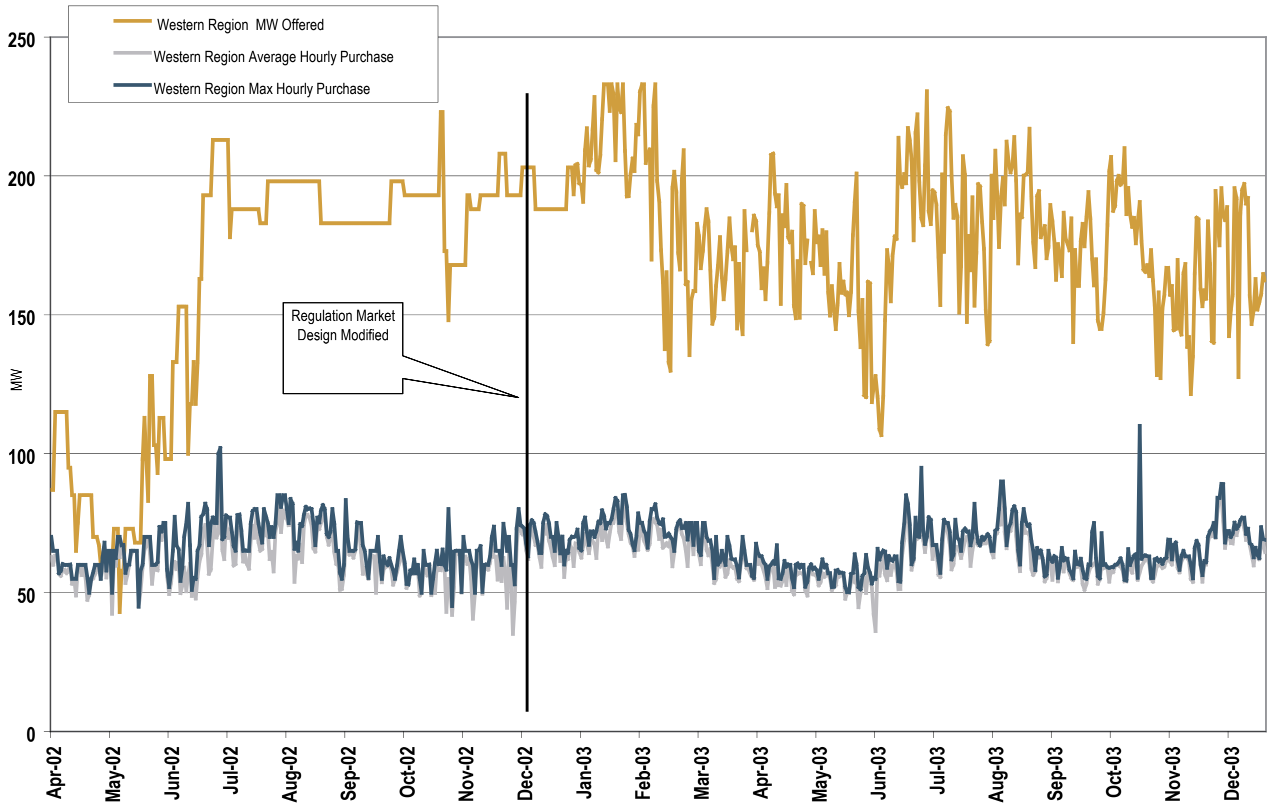


Figure 5-2 PJM Western Region Regulation MW Offered versus MW Purchased



Regulation Market Performance

Regulation Offers

Generators wishing to participate in the PJM Mid-Atlantic Region Regulation Market must submit price offers for specific units by hour 1800 of the day prior to the operating day. The regulation offer price is subject to a $100 per MWh offer cap and 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: (1) regulating status; (2) regulation capability; and (3) high and low regulation limits.

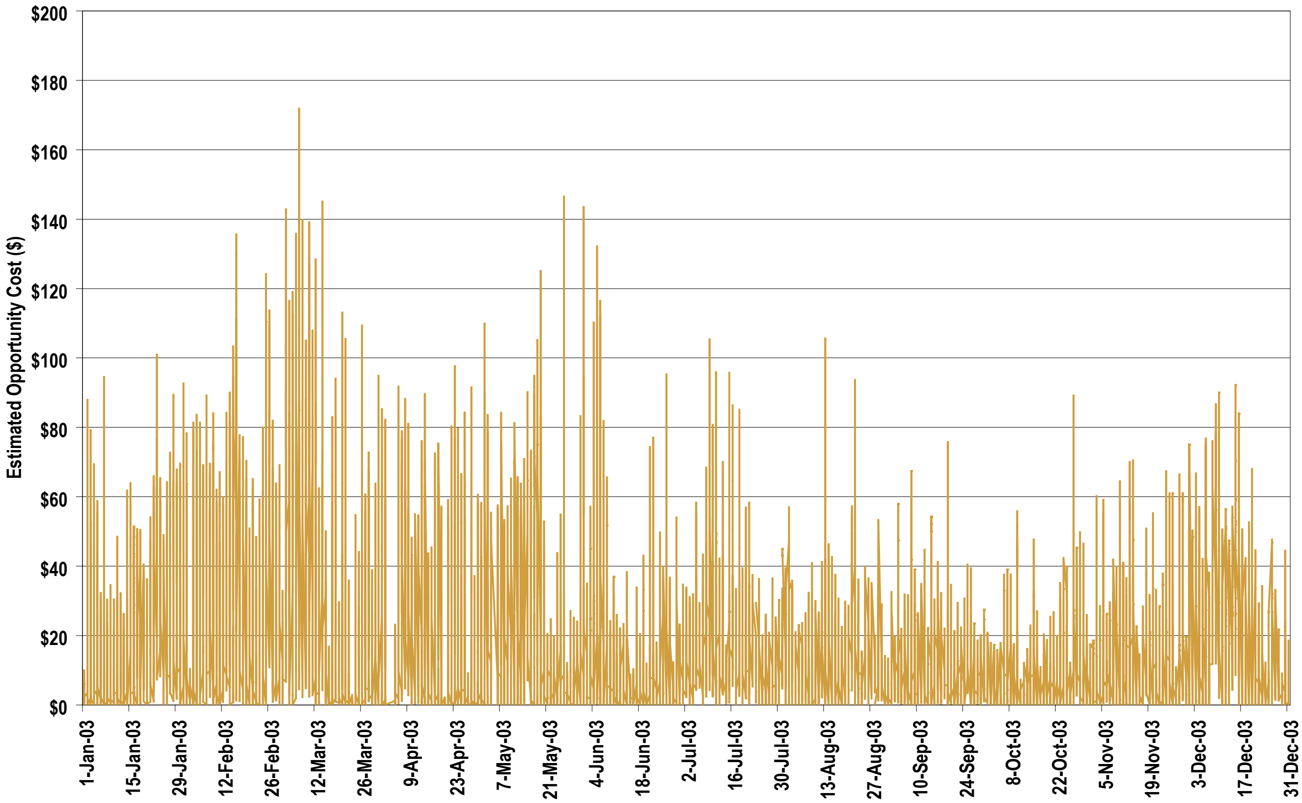
The Spinning Reserve and Regulation Markets are cleared simultaneously and cooptimized to reduce the cost of the combined products. In contrast to the previous PJM Regulation Market design, the current Regulation Market is cleared on a real-time instead of a day-ahead basis, and regulation prices are posted hourly throughout the operating day. With the current market design, the amount of self-scheduled regulation is confirmed 60 minutes prior to each operating hour, and the regulation assignments are made 30 minutes prior to each operating hour.

Regulation Market business rules for the PJM Western Region are similar to those for the PJM Mid-Atlantic Region. The PJM Western Region regulation offers are capped, however, at the marginal cost of providing the regulation service because there is only one regulation supplier in the PJM Western Region and thus there is not a competitive market. The PJM Western Region's regulating units are compensated at their individual regulation offer plus lost opportunity cost rather than at a single market-clearing price.

The PJM Regulation Market in the PJM Mid-Atlantic Region is cleared hourly based upon both the offers submitted by the units and the estimated hourly opportunity cost of each unit.[7] These two numbers are added together to provide the unit's hourly merit order price. The units are ranked by price and then units are selected to provide regulation according to the amount of regulation required for the hour. The price that results in the required amount of regulation is the regulation market-clearing price (RMCP), and the unit that sets this price is the marginal unit. Figure 5-3 illustrates estimated opportunity costs for the marginal units in the PJM Mid-Atlantic Region in 2003. All units chosen to provide regulation in the PJM Mid-Atlantic Region receive in payment the higher of the RMCP multiplied by the unit's assigned regulating capability, or the unit's regulation bid times its assigned regulating capability plus the individual unit's opportunity costs. Units in the PJM Western Region are compensated at the unit's own cost plus the actual opportunity cost for the unit while providing that regulation. There is no market-clearing price in the PJM Western Region.

7 PJM estimates the opportunity costs for units providing regulation based on a forecast of LMP for the upcoming hour. These opportunity costs are included in the market-clearing price.

Figure 5-3 Estimated 2003 Opportunity Costs (Regulation Marginal Units)



Regulation Prices

As Figure 5-4 and Figure 5-5 show, hourly regulation costs have been relatively stable since January 1999, despite several significant, short-lived spikes in the cost of regulation most notably in August 2001, August 2002 and during periods of higher prices in 2003. Price spikes were also experienced under the cost-based regime in the first half of 1999 because the credit paid to sellers of regulation was a function of the difference between hourly locational marginal price (LMP) and the regulation cost. During March and the summer months of 2003, several price spikes occurred. Those price spikes were smaller than in prior years primarily because Energy Market prices did not experience spikes during 2003. Price spikes in the Regulation Market have generally been the result of supply and demand fundamentals.

Figure 5-4 PJM Mid-Atlantic Region Hourly Regulation Cost per MW

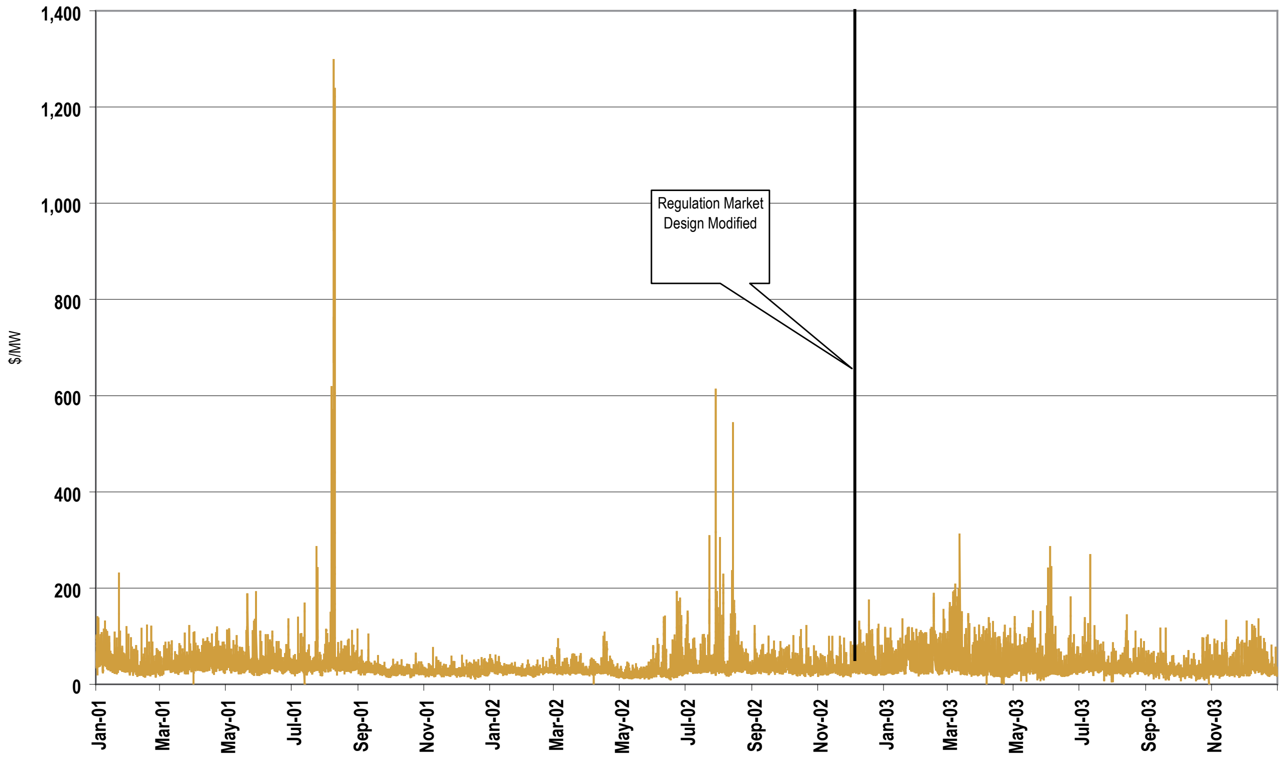


Figure 5-5 PJM Western Region Hourly Regulation Cost per MW

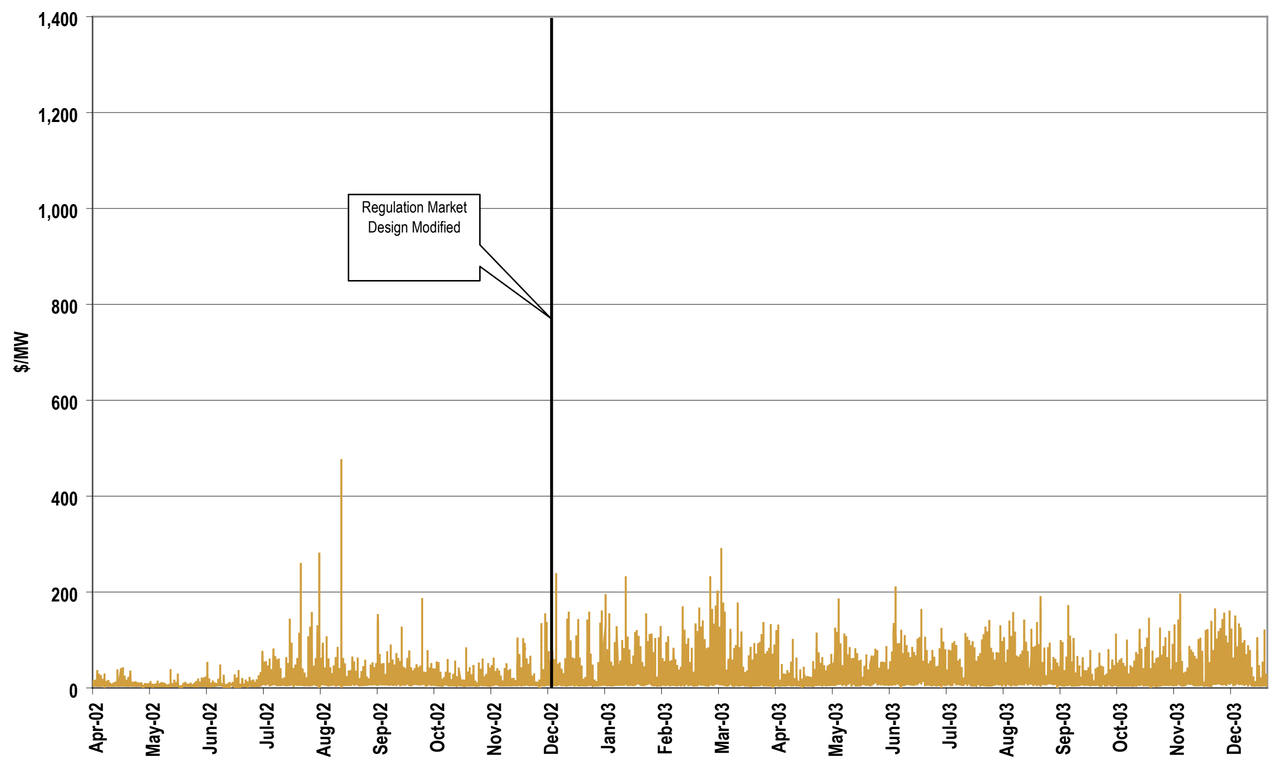


Figure 5-6 and Figure 5-7 compare the regulation cost per MW to the demand for regulation for the period from January 1999 through December 2003. Since the introduction of a Regulation Market, the per-unit cost of regulation has spiked when system LMP has spiked. Demand for regulation is a linear function of forecast energy demand. When loads increase, the result is an increase in demand for regulation. In addition, increases in system LMP cause opportunity costs to rise with the spread between LMP and the energy offers of the regulating units. System LMP increases with load because higher priced units must be dispatched to meet demand. As a result, load, energy prices and regulation prices are highly correlated.

Figure 5-6 PJM Mid-Atlantic Region Daily Regulation MW Purchased Compared to Cost per Unit

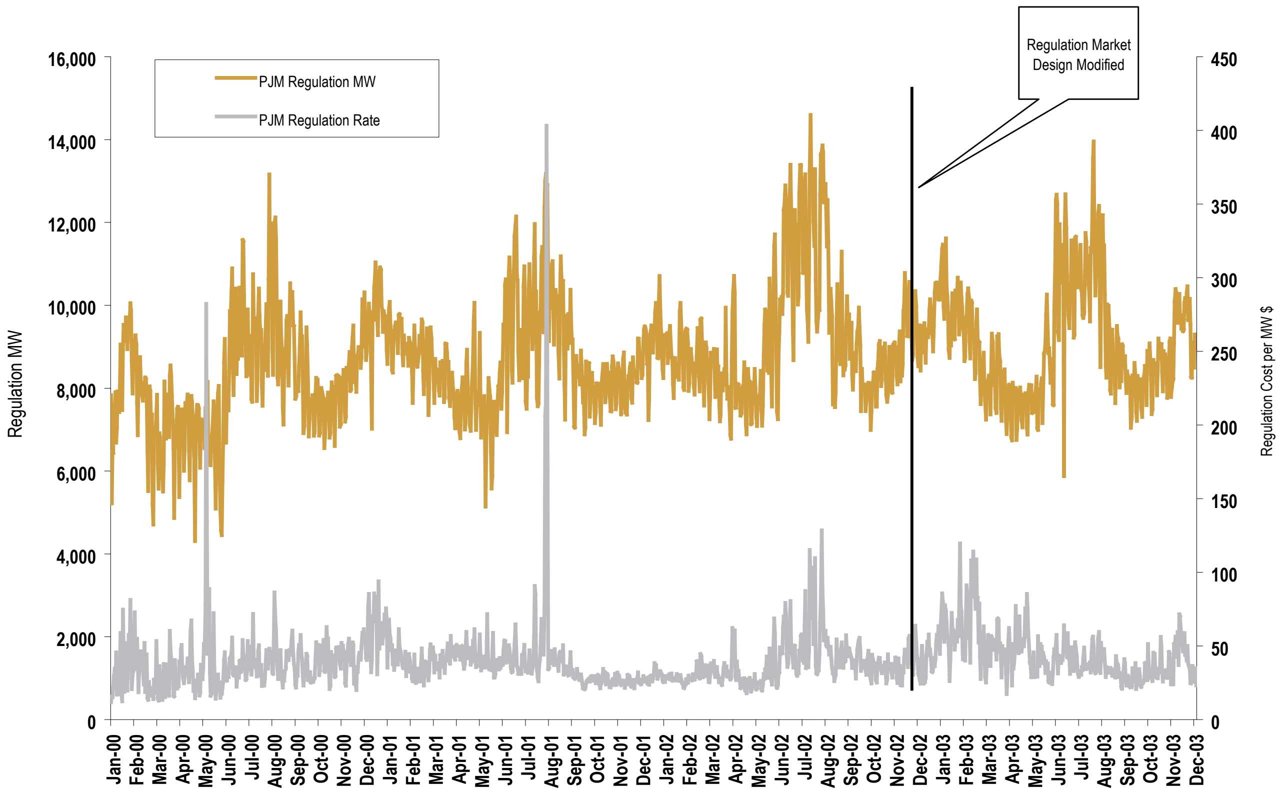


Figure 5-7 PJM Western Region Monthly Regulation MW Purchased Compared to Cost per Unit

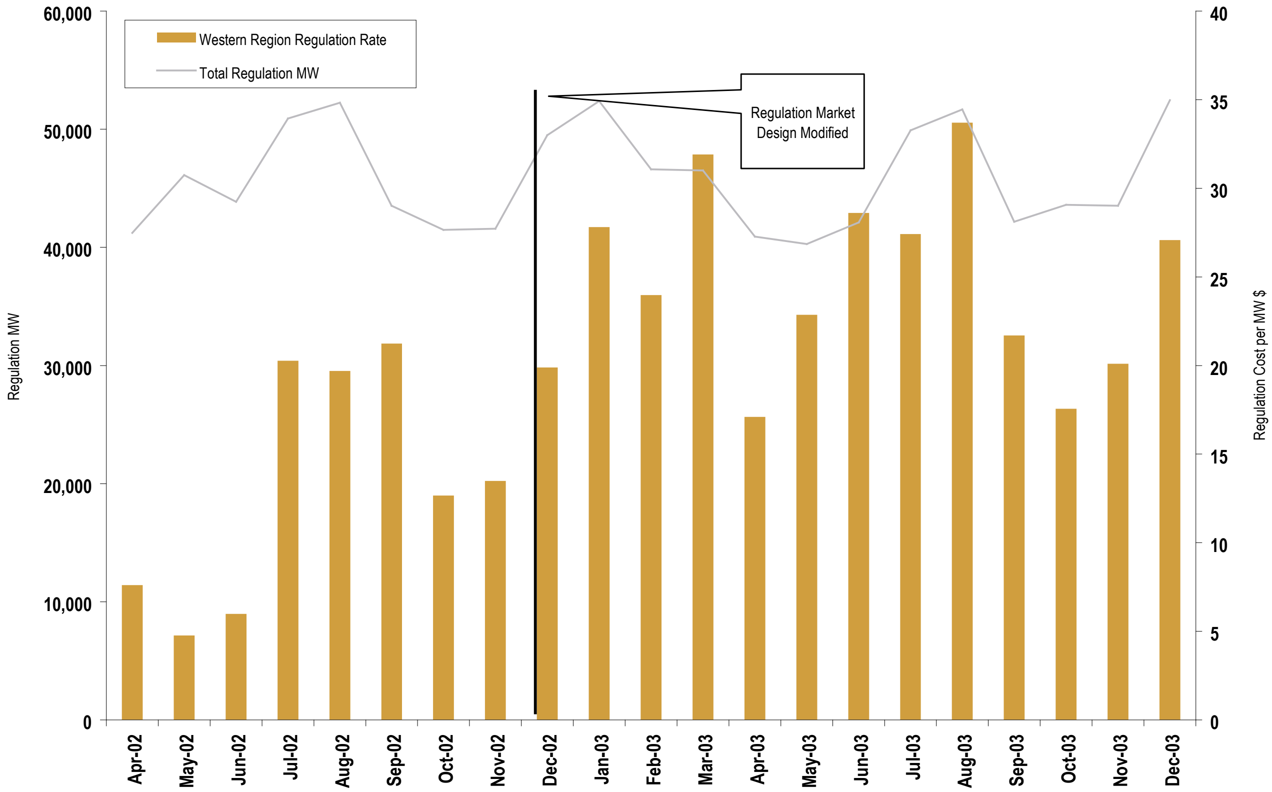
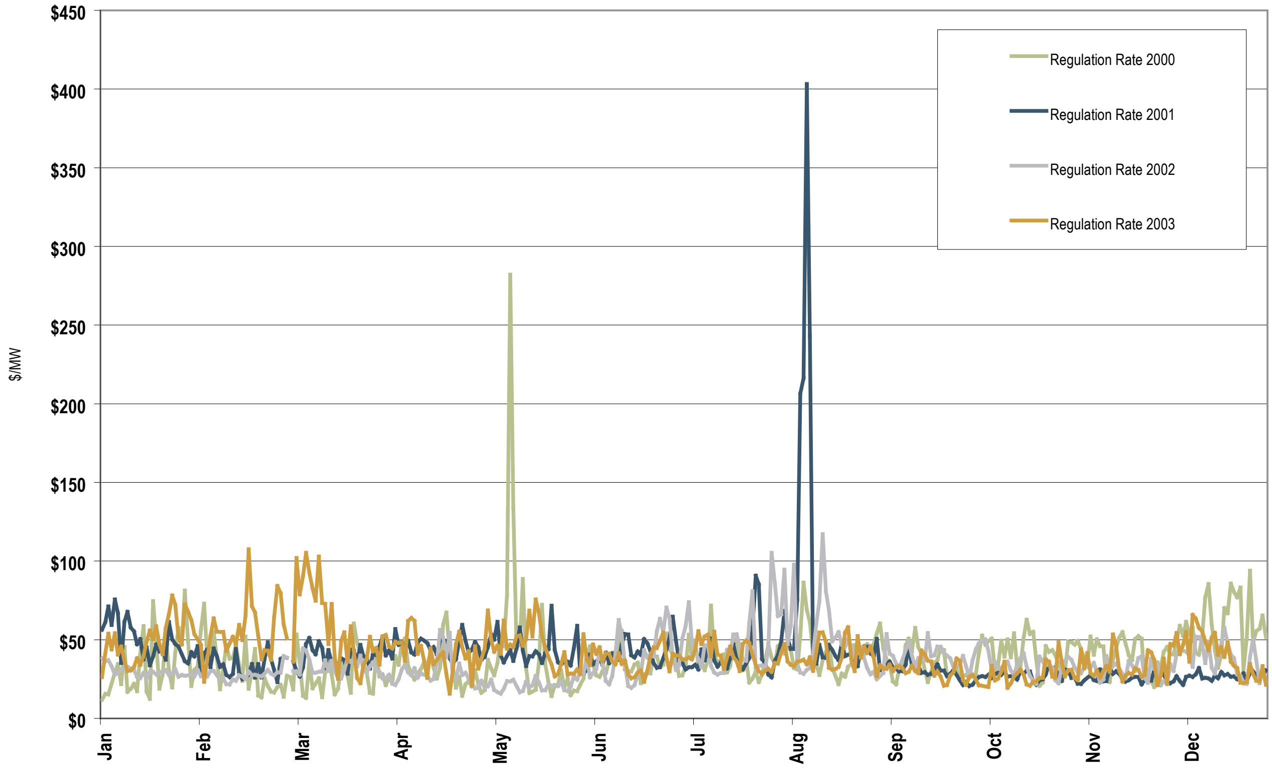


Figure 5-8 compares the average daily cost per MW of regulation for 2000, 2001, 2002 and 2003 (Figure 5-8 includes both the PJM Mid-Atlantic and the PJM Western Regions). The cost per MW of regulation for the PJM Mid-Atlantic and PJM Western Regions was 14 percent higher in 2003 than in 2002. In the PJM Mid-Atlantic Region, the cost per MW of regulation was 13 percent higher than in 2002 and 8 percent higher than in 2001. In the PJM Western Region, the cost per MW of regulation increased about 77 percent between 2002 and 2003. Figure 5-8 shows small spikes during February and March of 2003. Several factors explain the cost of regulation. All units are paid the market-clearing price for regulation.[8] If the RMCP is high because the marginal unit has a high offer price or a high opportunity cost, then most units receive the high RMCP. When LMPs are high, then lost opportunity costs for the units are high. Opportunity costs increased from 2002 to 2003, causing the 14 percent increase in cost per MW.

Figure 5-8 Daily Regulation Cost per MW for PJM Mid-Atlantic and PJM Western Regions: 2000 to 2003



Data presented in Figure 5-4, Figure 5-5 and Figure 5-8 show that the market-based, average per-MW price of regulation has remained consistent with the price of regulation under the cost-based system in place before the market was implemented. This consistency in the price of regulation suggests that the results of the Regulation Market have been competitive since its introduction.

Data presented in Figure 5-6 and Figure 5-7 show the expected relationship between demand and price. Price is a positive function of demand as would be expected with an upward sloping supply curve. Again, the result is consistent with the conclusion that results of the Regulation Market were competitive in 2003.

The close relationship between the Regulation Market and the Energy Market is essential for the efficient and competitive provision of both energy and regulation. This close relationship, however, also creates the potential for market issues in the Energy Market to be transferred to the Regulation Market. For example, a price in the Energy Market that is above competitive levels tends to increase the price of regulation. Economic withholding in the Energy Market can also impact the Regulation Market. Although there is no evidence that such behavior affected the price of regulation in 2003, the potential for issues requires ongoing scrutiny.

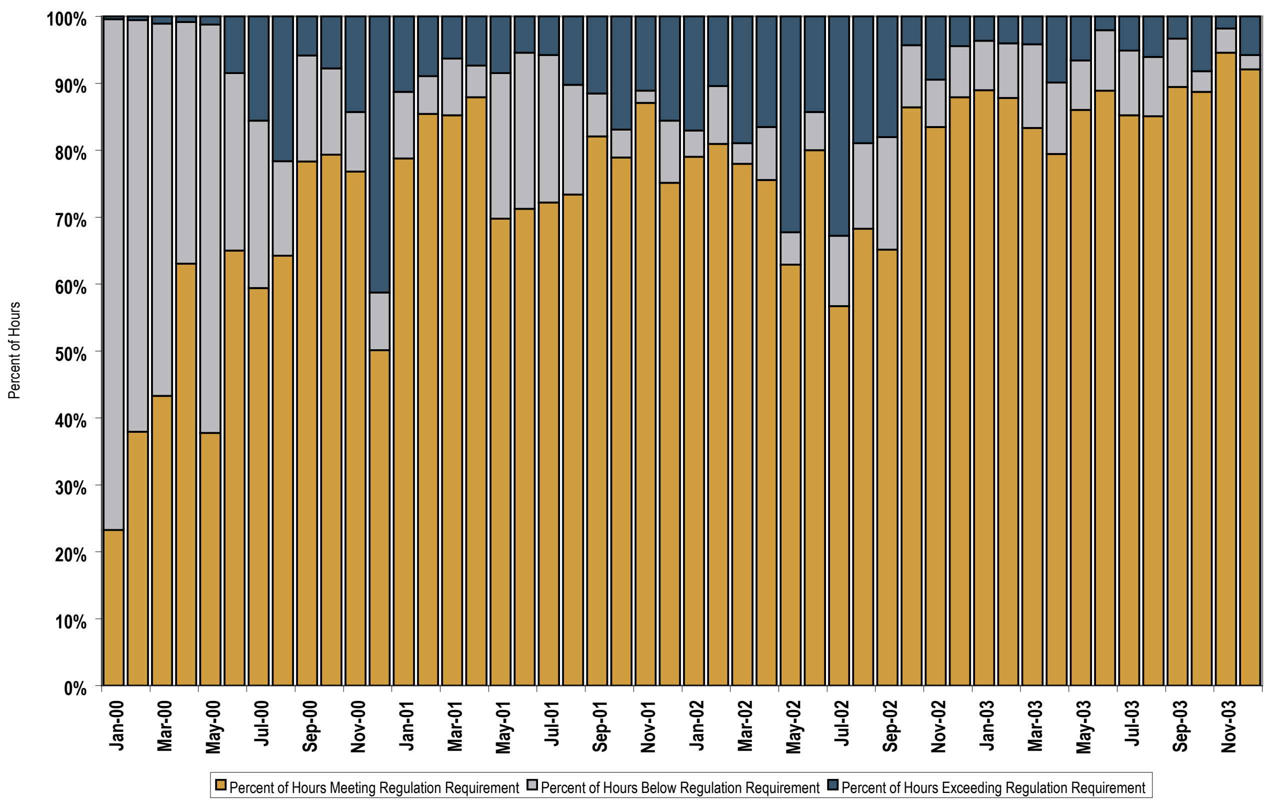
8 This is true in the PJM Mid-Atlantic Region, but is not true in the PJM Western Region.

Regulation Availability

Under both the prior administrative approach and the current market-based approach, system regulation performance is related to the incentives to provide regulation. Under the administrative regime, the system had less than the target amount of regulation at times during some off-peak hours and at times during the transition between off-peak and on-peak periods. This shortfall could have resulted from the fact that the administrative payments for regulation were based on the difference between the current hourly LMP and a fixed regulation cost based on an historical average energy cost calculation. The result, during some off-peak hours, was that there might have been little incentive to provide regulation. Regulation Market design provides better incentives to owners based on hourly, unit-specific opportunity costs and the submission of a current regulation offer price.

Figure 5-9 shows that during the first five months of 2000, the supply of regulation was consistently less than the target level of regulation. Regulation availability increased significantly after the introduction of a Regulation Market. The proportion of hours in which PJM met the minimum regulation target doubled from an average of about 42 percent in the first five months of 2000 to about 75 percent after introduction of the Regulation Market until November 2002. Since the introduction of the current Regulation Market in December 2002, the proportion of hours when PJM met the minimum regulation target increased to an average of about 86 percent.

Figure 5-9 Percent of Hours within Required PJM System Regulation Limits



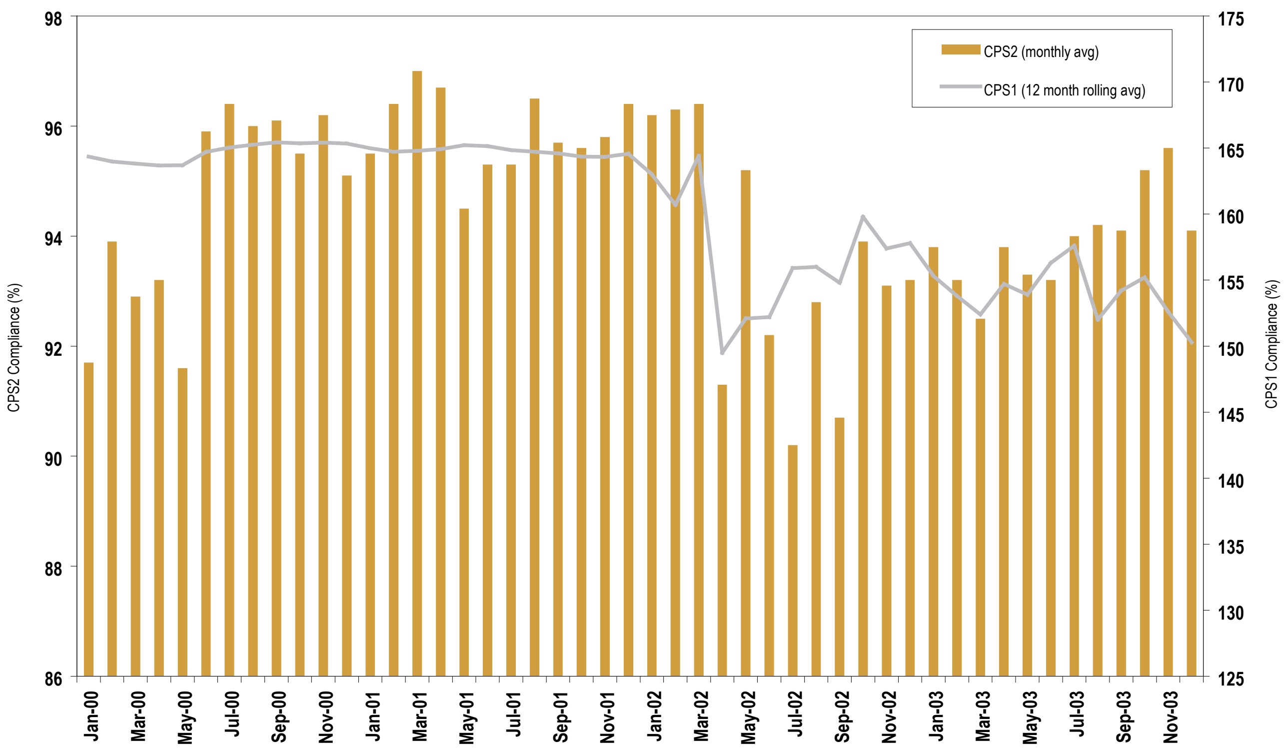
Regulation helps to maintain the balance between load and generation by moving the output of selected generators up and down via an automatic control signal.[9] While the improved availability of regulation illustrated in Figure 5-9 is important, the ultimate success of regulation in balancing load and generation is not directly measured by regulation performance, but is measured by PJM's compliance with North American Electric Reliability Council (NERC) Control Performance Standards CPS1 and CPS2.[10]

9 PJM documents with information on regulation include the "PJM Manual for Pre-Scheduling Operations, Manual M-10" and the "PJM Manual for Scheduling Operations, Manual M-11."

10 "NERC Operating Manual," March 29, 2001.

Figure 5-10 shows PJM's regulation performance as measured by the NERC Control Performance Standards CPS1 and CPS2. These standards measure the relationship between generation and load. CPS1 is measured on a 12-month rolling average and provides what NERC terms a "frequency-sensitive evaluation" of how a control area meets its demand requirements. CPS2 measures the balance between load and generation on a 10-minute basis. In order to pass the control requirements, CPS1 must be greater than or equal to 100 percent, and CPS2 must be greater than or equal to 90 percent. In 2003, performance exceeded both of these necessary control requirements. Figure 5-10 shows that, as measured by CPS1, since introduction of the Regulation Market, performance was stable, declined after the integration of the PJM Western Region and has improved since that time. As measured by CPS2, since introduction of the Regulation Market, performance was stable, declined after the integration of the PJM Western Region and has been stable since that time. Since the introduction of the new Regulation Market on December 1, 2002, CPS1 has not changed significantly, but CPS2 has decreased about 3 percent.

Figure 5-10 CPS1 and CPS2 Performance



Spinning Reserve Service

Spinning Reserve Market Structure

Spinning reserve is an ancillary service defined to be generation which 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 combustion turbines (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 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 in 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 provide a response when needed. Tier 1 spinning payments or credits are equal to the integrated increase in MW output from each generator over the length of a spinning event, times 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.[11]

Under the Spinning Reserve Market rules, Tier 2 spinning resources are paid in order to be available as spinning reserves, regardless of whether the units are called upon to generate in response to a spinning event. The price for Tier 2 spinning resources is determined in a market for Tier 2 spinning resources. Under the new market rules, several steps are necessary before the Tier 2 Spinning Reserve Market is cleared for an hour. 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, 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 cost, Tier 2 resource needed to fulfill spinning requirements. A unit's merit order price is a combination of the estimated unit opportunity cost per MWh of capability, the cost of energy use per MWh of capability, the unit's start-up cost, and the unit's spinning offer price. The energy use is calculated as the forecast LMP multiplied by the ratio of MW of energy use over spinning capability.

The spinning offer price submitted for a unit can be no greater than the maximum value of the unit's operating and maintenance cost plus a $7.50 per MWh margin.[12] The market-clearing price is comprised of the marginal unit's offer price, start-up cost, energy use and 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 opportunity cost and cost of energy use incurred. The PJM Mid-Atlantic Region Tier 2 Spinning Reserve Market is a cost-based market based on the MMU analysis demonstrating that there were insufficient competitors to ensure a competitive outcome. This concern is exacerbated by the fact that the number of competitors can be reduced significantly further when the Spinning Reserve Market becomes local due to transmission constraints.

11 "PJM Spinning Reserve Market Business Rules," November 13, 2002.
12 "PJM Spinning Reserve Market Business Rules," November 13, 2002.

The PJM Western Region operates under business rules that are similar to those in the PJM Mid-Atlantic Region, with key exceptions based on competitive concerns. The Spinning Reserve Market in the PJM Western Region is cost-based because there is only a single supplier of spinning reserves in the PJM Western Region. The spinning offers of the PJM Western Region generators must reflect the marginal cost of providing spinning reserve from these generators. Generators that provide spinning reserve are compensated on a unit-specific basis at a level determine by a combination of the unit's spinning offer price, the unit's opportunity cost and the cost of the energy use incurred by the unit in providing the spinning reserve, rather than based on a market-clearing price.[13]

Concentration is high in the Tier 2 Spinning Reserve Market. In 2003, average HHI for the PJM Mid-Atlantic Region was 2544, and in the PJM Western Region there was only one supplier (HHI was 10000).

Spinning Reserve Market Performance

Spinning Reserve Offers

Figure 5-11 compares the average hourly amount of required Tier 2 spinning reserve by month to the amount of Tier 2 spinning reserve purchased on an average hourly basis. The difference between required spinning reserve and spinning reserve provided by condensing units is provided by Tier 1 units, and the average difference in 2003 was 802 MW. What is now termed Tier 1 spinning was not compensated explicitly under prior market rules. The new Spinning Reserve Market rules allow such units to be compensated if they respond to a spinning event.

The PJM spinning requirement consists of 75 percent of the largest contingency on the PJM system provided that 50 percent of the largest contingency is available as nonsynchronized, 10-minute reserve.[14] Between 1999 and 2003, the monthly average required spinning reserve ranged from about 1,100 MW to 1,512 MW and averaged about 1,200 MW (Figure 5-11). Actual hourly spinning requirements ranged from 937 MW to 2,513 MW.

Spinning requirements during the last three months of 2003 were higher mainly because of a penalty that PJM incurred which resulted in the requirement to carry extra spin. On July 29, 2003, PJM experienced a NERC disturbance control standard (DCS) violation. The DCS is used by each control area to monitor performance during recovery from disturbance conditions, or outages or failures that threaten system reliability.[15] Within 15 minutes of the start of a disturbance, the area control error (ACE) must return to zero or to its predisturbance level. During the disturbance event that PJM experienced, ACE did not return to zero until 15:45 minutes into the event, or 45 seconds longer than permitted. The timing was largely because the dispatcher's prepared all-call message requesting spinning was not submitted at the proper time, despite the dispatcher having recognized the need for 100 percent spinning. It was not until the PJM Western Region recognized the need for spinning that the dispatcher became aware that the message had not been sent. Though quick-start generation was brought online, the DCS was still violated. PJM has been required, therefore, to carry 105.2 percent of the normal first contingency reserve (about an extra 60 MW) of spinning reserve from October 3, 2003, until January 3, 2004.

13 "PJM Spinning Reserve Market Business Rules," November 13, 2002.
14 "PJM Spinning Reserve Market Business Rules," November 13, 2002.
15 "PJM Dispatching Operations Manual," Rev 8, April 1, 2002.

Figure 5-11 PJM System Required Tier 2 Spin versus Tier 2 Spinning Purchased

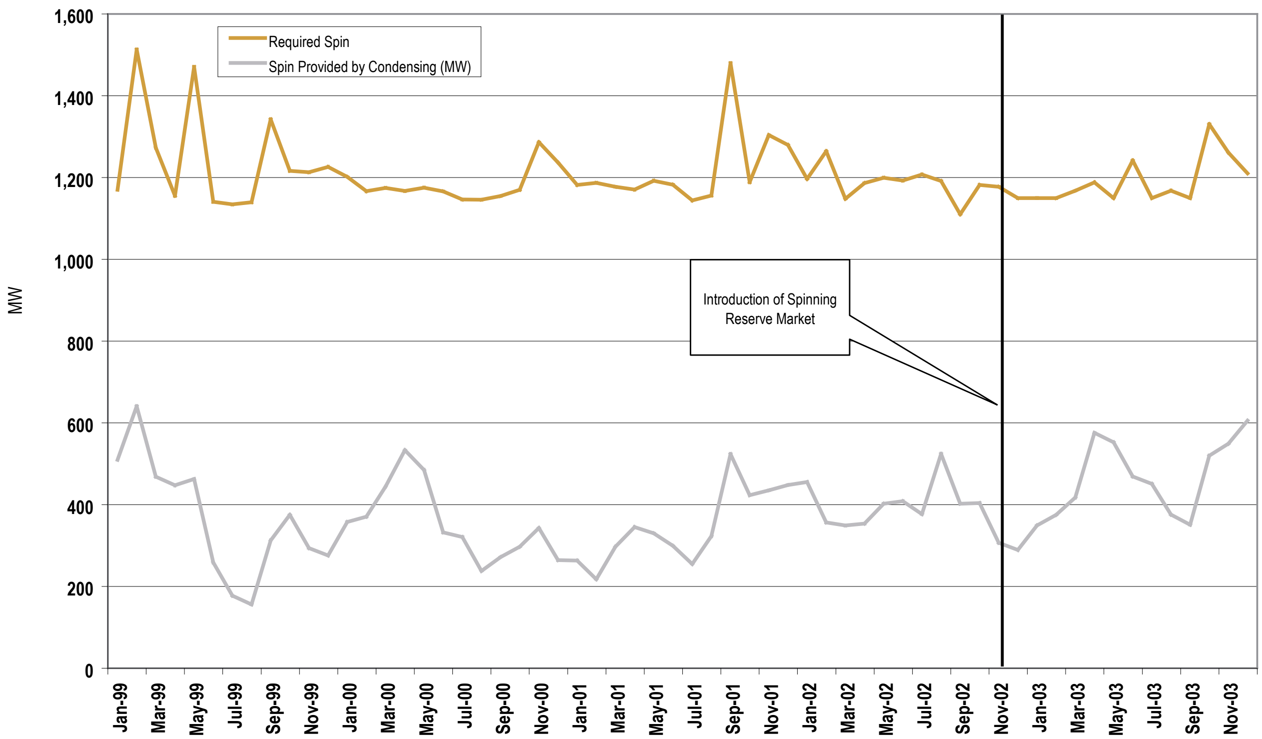
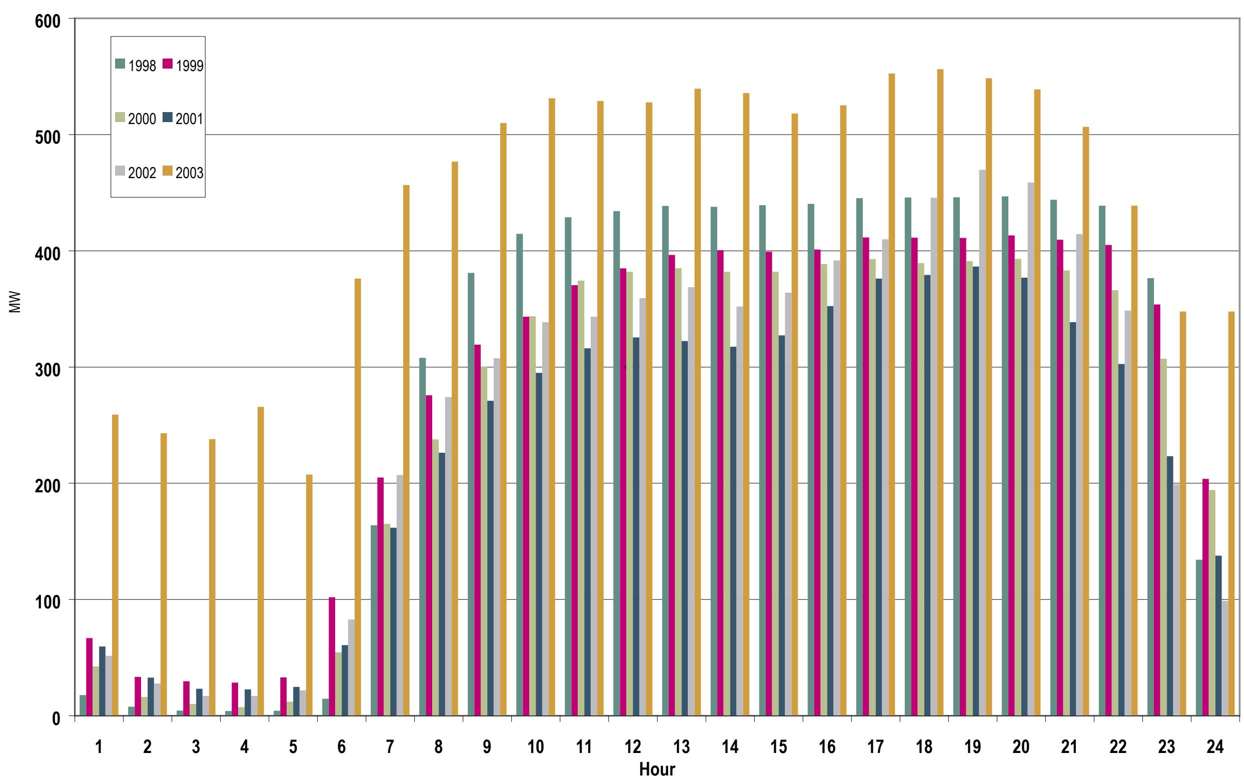


Figure 5-12 shows the annual average hourly Tier 2 spinning MW that PJM has purchased since 1998. Noticeably, these Tier 2 spinning MW are higher during 2003 than during prior years. Total spinning requirements were higher in 2003 and PJM operators relied more heavily on Tier 2 spinning in 2003, after the introduction of the new market.

Figure 5-12 PJM System Average Hourly Tier 2 Spinning MW



Spinning Reserve Prices

Figure 5-13 shows the average cost per MW associated with meeting PJM's demand for spinning reserve. The average cost per MW decreased from about $21 per MW in 2002 to about $15 per MW in 2003.

Figure 5-13 Total Tier 2 Spinning Credits per MW

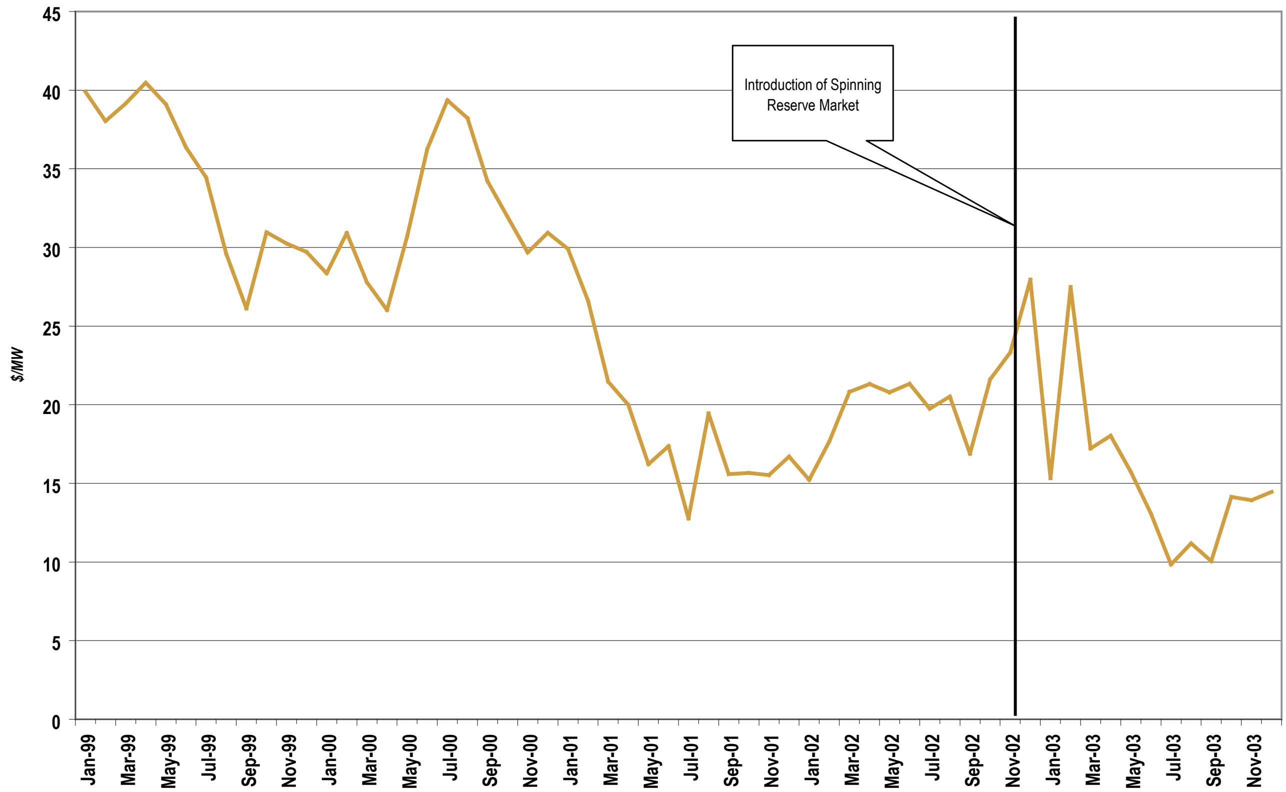


Figure 5-14 displays Spinning Reserve Market Tier 2 market-clearing prices (SRMCP) for 2003. Price spikes were seen at times in the period from March through July and again in October. As was true in the Regulation Market, these spikes reflect the fact that the marginal units' opportunity costs were relatively high during certain hours as the result of high energy prices. Offer cost was not a factor in high SRMCPs. The marginal units were needed in order to meet the spinning requirements for the region. The spike in October can be attributed to a high spinning requirement that resulted from the penalty associated with the DCS violation and from a specific generating unit being out of service.

Figure 5-14 2003 PJM Mid-Atlantic Region Spinning Reserve Market-Clearing Prices

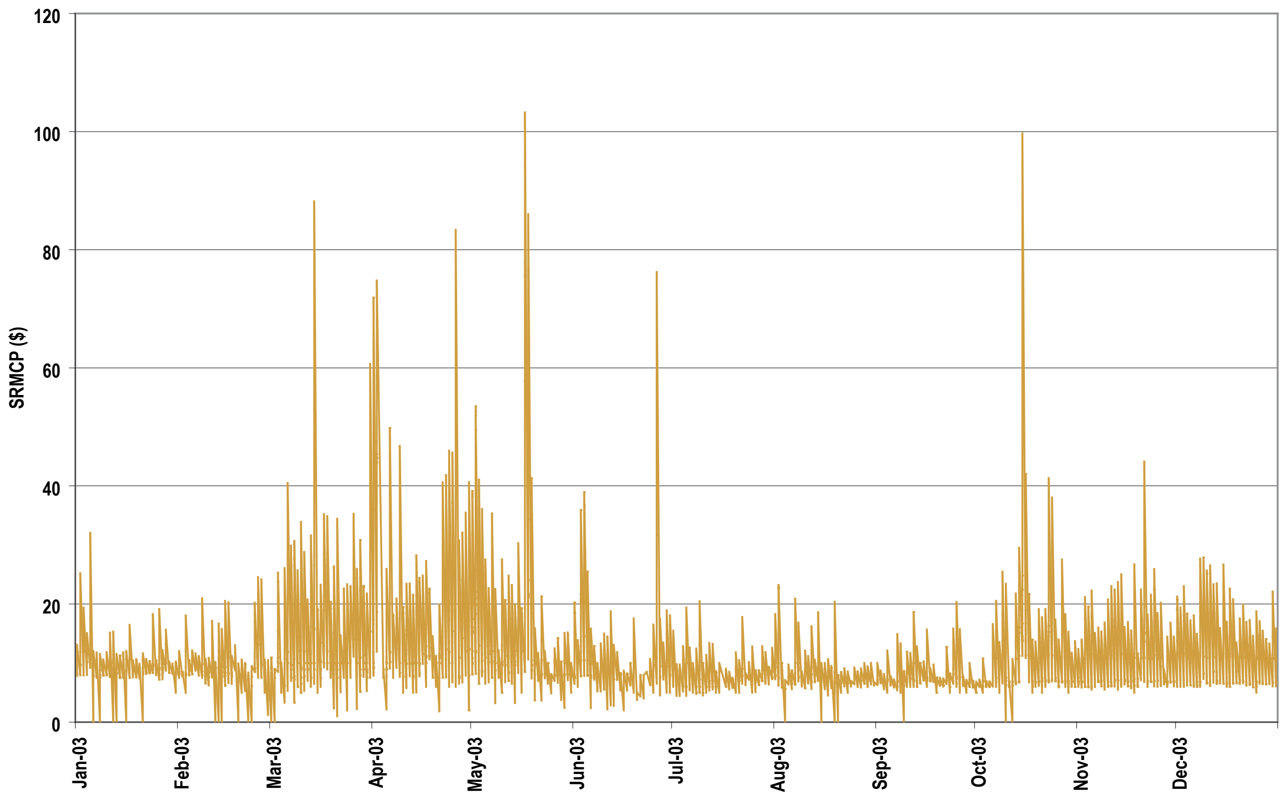
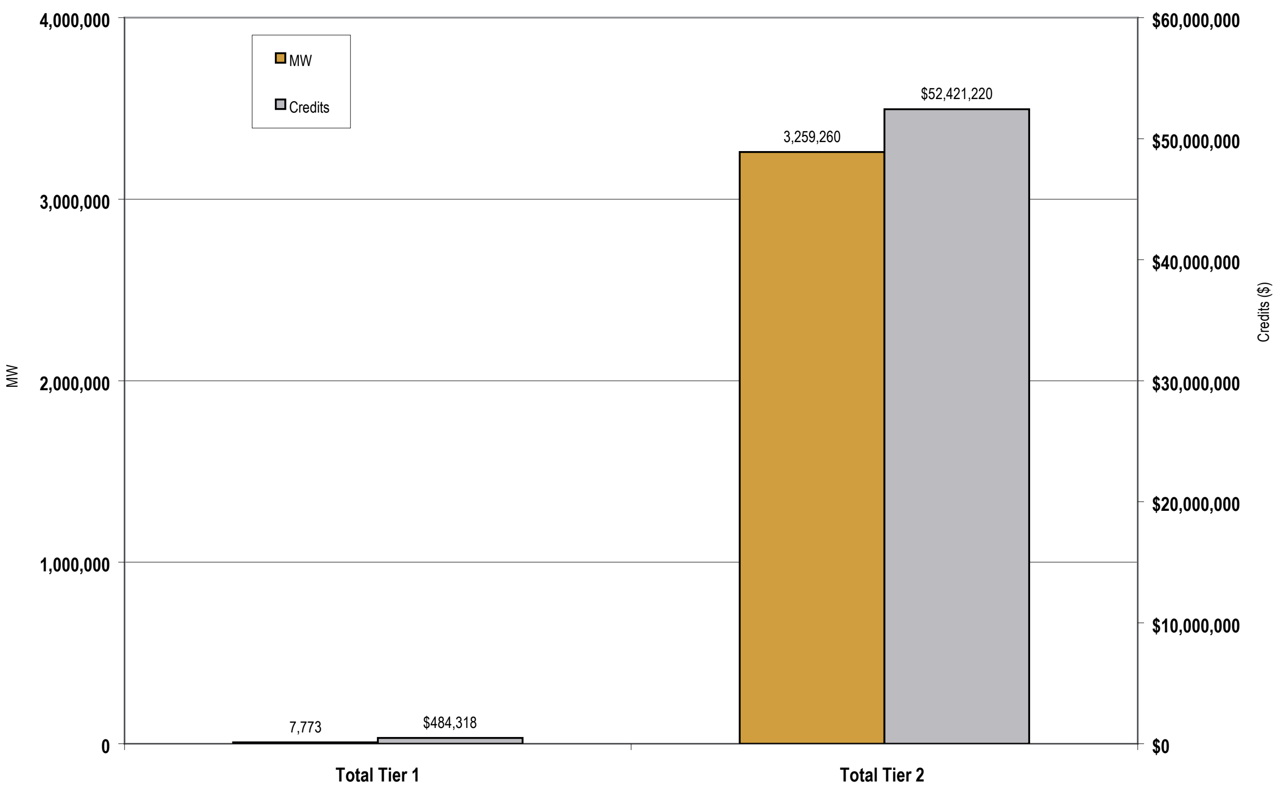


Figure 5-15 shows the level of Tier 1 and Tier 2 spinning reserve explicitly purchased from suppliers during 2003, the first full year of the new market. Tier 1 resources are paid only if they respond during spinning events while Tier 2 resources are paid for providing hourly reserves. As a result, more Tier 2 resources were purchased and Tier 2 payments were higher than Tier 1 payments. In 2003, 7,773 MW were purchased from Tier 1 resources for about $62 per MW, and 3,259,260 MW were purchased from Tier 2 resources for about $16 per MW. Total payments for spinning resources in 2003 were $217,178,221, an increase of about 18 percent from total payments for spinning resources in 2002 and an increase of 31 percent from 2001. This increase is mainly attributable to a greater demand for spinning reserves.

Figure 5-15 2003 PJM System Spinning Volumes and Credits: Tier 1 and Tier 2



Section 6 – Congestion

Congestion occurs when available, low-cost energy cannot be delivered to all loads because of limited transmission facilities. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units must be dispatched to meet that load.[1] The result is that the price of energy in the constrained area is higher than elsewhere and congestion exists. Locational marginal prices (LMPs) reflect the cost 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.

Overview

- **Total Congestion.** Congestion costs were approximately $499 million in 2003, a 16 percent increase from $430 million in 2002. Congestion costs have ranged from 6 to 9 percent of annual total PJM billings since 2000. Congestion costs declined from 9 percent of total billings in 2002 to 7 percent of total billings in 2003.

- **Hedged Congestion.** Although some months had congestion credit deficiencies, excess congestion charges collected in other months offset all but $23 million of the deficiencies, and FTRs were paid at 96 percent of the target allocation level in 2003, compared to 95 percent in 2002.

- **Monthly Congestion.** Differences in monthly congestion costs continued to be substantial. In 2003, these differences were driven by loop flows, 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.

- **Zonal Congestion.** LMP differentials were calculated for each PJM Mid-Atlantic Region zone to provide an approximate indication of the geographic dispersion of congestion costs. The data show some new overall congestion patterns in 2003.

- **Congested Facilities.** Both interface and transformer facilities experienced decreases in congested hours during 2003, while total congested hours on lines remained nearly unchanged from 2002 levels. There were increases in constrained hours on 230 kV lines.

- **Local Congestion.** Local congestion in the Delmarva Power & Light Company (DPL) zone continued to decrease in 2003 because of ongoing transmission reinforcement projects. Transmission reinforcements at Erie resulted in significantly less congestion in the Pennsylvania Electric Company (PENELEC) service territory and at the PJM western border. Congestion rose, however, in the Public Service Electric and Gas Company (PSEG) service territory on the Cedar Grove-Roseland 230 kV, Edison-Meadow Road 138 kV and Branchburg-Readington 230 kV lines.

- **Congestion Management Pilot.** A pilot program was conducted during the period July 11, through September 31, 2003, to measure the effectiveness of a proposed contingency management policy at reducing the incidence of off-cost operations. Analysis indicated 272 hours of avoided real-time, off-cost operations because of the new thermal emergency limits supplied under the pilot program.

Congestion associated with flows at the PJM/AEP and PJM/VAP interfaces and persistent congestion in defined areas within PJM suggest the importance of PJM's continuing efforts to improve the sophistication of its congestion analysis. Congestion analysis is central to implementing the United States Federal Energy Regulatory Commission (FERC) order to develop an approach identifying areas where investments in transmission would relieve congestion

1 This is referred to as dispatching units out of merit order. 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.

where that congestion might enhance generator market power and where such investments are needed to support competition.[2]

In an order dated December 19, 2002, the FERC granted PJM full status as a regional transmission organization (RTO) and, among other rulings, directed PJM to make further compliance filings, principally to revise PJM's Regional Transmission Expansion Planning Protocol (RTEPP) 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."[3]

To comply with the RTEPP requirement, PJM submitted changes to its tariff and to its Operating Agreement on March 20, 2003, expanding its regional transmission planning protocol to include economic planning. PJM stated that it will, when appropriate, initiate upgrades or expansions of the transmission system to enhance the economic and operational efficiency of wholesale electric service markets in the PJM service area. PJM explained that its economic planning will identify transmission upgrades needed to address unhedgeable congestion. 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 generation or hedged with available annual Financial Transmission Rights (FTRs).[4] The new planning process intends that if market forces do not resolve unhedgeable congestion within an appropriate time period, PJM will determine, subject to cost-benefit analysis, transmission solutions that will be implemented through the RTEPP.

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Balancing Markets. Transmission congestion in the Day-Ahead Market can be directly hedged by using 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 Market.

Total congestion charges are the sum of the day-ahead and balancing market congestion charges plus the day-ahead and balancing market congestion charges implicitly paid in the Spot Market, minus any negatively valued FTR target allocations. The day-ahead and balancing market congestion charges consist of implicit and explicit congestion charges.

- **Implicit Congestion Charges**. These charges are incurred by network 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 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 the supply at every bus times the bus LMP, where supply includes generation, increment bids and purchase transactions. In the Balancing 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 and sinks in the Day-Ahead Market. Balancing 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 Charges**. These charges are equal to the difference between total spot market purchase payments and total spot market sales revenues.

2 96 FERC ¶61,061 (2001).

3 101 FERC ¶61345 (2002).

4 See generally 104 FERC ¶61,124 (2003).

Total Congestion

Table 6-1 shows total congestion by year from 1999 through 2003. The $499 million of congestion charges incurred during 2003 was 16 percent higher than the $430 million incurred in 2002.

The increased size of the total Energy Market contributed to the increase in total congestion. While total congestion increased, congestion costs declined to 7 percent of total PJM billings in 2003 from 9 percent in 2002.

The integration of the PJM Western Region for the entire year of 2003 and nine months of 2002 contributed to the measured increase in total congestion. The PJM Western Region was part of PJM for the last nine months of 2002 and for all of 2003. Congestion was $40 million lower during the last nine months of 2003 than during the last nine months of 2002.

Even though 2003 saw a moderating of congestion frequency at the Bedington-Black Oak and APS south interfaces (both interfaces between APS or the PJM Western Region and the PJM Mid-Atlantic Region) and at the Wylie Ridge transformer, these constraints continued to contribute significantly to overall congestion (Table 6-4). Increases in congestion frequency on the Kammer and Doubs transformers and at the PJM west 500, Central and Eastern Interfaces offset the effects of these decreases. The two APS interfaces each affected prices for about 25 percent of PJM load, while the Wylie and Kammer transformers each affected about 95 percent. Increased congestion on the west 500 as well as on the Eastern and Central Interfaces, which together impact price for 50 to 80 percent of PJM load, also contributed significantly to overall congestion in 2003. Transmission facilities in northern New Jersey and the Doubs transformer, which affects about 10 percent of PJM load, also exhibited increased congestion.

Loop flows at the PJM/AEP and PJM/VAP interfaces early in the year also contributed to total congestion.

Table 6-1 Total Congestion

Year	Congestion Charges	Percent Increase	Total PJM Billing	Percent Of PJM Billing
2003	$499	16%	$6,900	7%
2002	$430	58%	$4,700	9%
2001	$271	105%	$3,400	8%
2000	$132	149%	$2,300	6%
1999	$53	N/A	N/A	N/A
Total	$1,385	N/A	N/A	N/A

Hedged Congestion

Table 6-2 lists congestion charges, FTR target allocations and credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month accounting period, excess congestion charges are normally used to offset any monthly congestion credit deficiencies. This year the congestion accounting period is changing from a calendar year to the PJM planning year. To facilitate this change, the 2003 congestion accounting year has been extended until May 31, 2004.

Table 6-2 2003 PJM Congestion Accounting Summary (Dollars in millions)

Month	Congestion Charges	FTR Target Allocations	Congestion Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Dec-03	$15	$13	$13	100%	$0	$2
Nov-03	$18	$17	$17	100%	$0	$1
Oct-03	$32	$33	$32	97%	$1	$0
Sep-03	$42	$44	$42	95%	$2	$0
Aug-03	$59	$53	$53	100%	$0	$6
Jul-03	$96	$85	$85	100%	$0	$10
Jun-03	$52	$57	$52	90%	$6	$0
May-03	$27	$41	$27	67%	$14	$0
Apr-03	$27	$23	$23	100%	$0	$4
Mar-03	$52	$42	$42	100%	$0	$10
Feb-03	$14	$18	$14	77%	$4	$0
Jan-03	$66	$94	$66	70%	$29	$0
Total	$499	$521	$466	89%	$56	$33
Final 2003 Values						
Total	$499	$521	$499	96%	$23	$0

Although some months had congestion credit deficiencies, excess congestion charges collected in other months offset all but $23 million of the deficiencies, and FTRs were paid at 96 percent of the target allocation level in 2003, compared to 95 percent in 2002. Although aggregate FTRs provided a hedge against 96 percent of the target allocation level, 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.

The bulk of the $23 million congestion credit deficiency for 2003 was incurred during January and was, in significant part, the result of loop flows at the PJM/AEP and the PJM/VAP interfaces. This phenomenon led PJM to modify the pricing of energy at these interfaces.[5]

Monthly Congestion

Table 6-3 shows congestion charge variations by month, day and hour. During 2003, monthly congestion charges ranged from a maximum of $96 million in July to a minimum of $13 million in December. Mean monthly congestion charges of $41 million in 2003 were greater than mean monthly charges of $36 million in 2002.

Table 6-3 2003 Transmission Congestion Revenue Statistics (Dollars in millions)

Period	Maximum	Mean	Median	Minimum	Range
Monthly	$96	$38	$37	$13	$83
Daily	$9.6	$1.4	$1.3	($0.8)	$10.4
Hourly	$1.1	$0.06	$0.07	($0.2)	$1.3

The range of monthly congestion costs (i.e., the difference between the monthly minimum and maximum) decreased in 2003 to $83 million from $99 million in 2002. Similarly, the range of daily congestion costs dropped from $12.1 million in 2002 to $10.4 million in 2003. The difference between hourly minimum and maximum congestion revenues also decreased, from $4.7 million in 2002 to $1.3 million in 2003.

5 See Section 3, "Interchange Transactions," for additional information on loop flows.

Approximately 32 percent of all 2003 congestion occurred during the summer and winter peak-demand months of July and January. January exhibited the largest increase from the previous period, with 2003 congestion $56 million higher than 2002. This increase was caused by loop flows at the PJM/AEP and the PJM/VAP interfaces that led to a change in the pricing of energy at these interfaces. In 2002, 40 percent of congestion occurred during July and August. In 2003, five months had congestion charges over $50 million, relatively unchanged from 2002 when five months had congestion charges of more than $47 million.

The bulk of the high monthly congestion charges have often accrued during just a few days each month. In 2003, the maximum monthly congestion cost of $96 million occurred in July, with $32 million of congestion incurred during the on-peak hours of just five days. The causal facilities for this congestion were the Eastern and Bedington-Black Oak Interfaces which were constrained during 88 percent and 38 percent of these hours, respectively. The Eastern Interface restricts transfers into New Jersey, Philadelphia and Delaware, while Bedington-Black Oak limits transfers into the southwestern part of the PJM Mid-Atlantic Region. Pruntytown-Mt. Storm 500, a main west-to-east path in APS, was also constrained during 68 percent of these hours.

The maximum daily congestion charge of $9.6 million occurred on July 8, 2003, the third-highest load day of the year. Again, the Eastern Interface and Pruntytown-Mt. Storm 500 were largely responsible for the high level of congestion. Five of the top 10 congestion hours of the year also occurred on this day, each with about $0.9 million of congestion.

The maximum hourly congestion also occurred on July 8, 2003, when $1.1 million in congestion charges were accrued during the hour ending 1600.

The peak demand for the year occurred during hour 1600 on August 22, 2003, when demand reached 61,500 MW. Congestion costs of $0.6 million were incurred, an amount that places the hour in the middle of the range of hourly 2003 congestion cost.

Zonal Congestion

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.

LMP differentials were calculated for each PJM Mid-Atlantic Region zone to provide an approximate indication of the geographic dispersion of congestion costs. These LMP differentials, presented in Figure 6-1 for 2001 through 2003, were calculated as the difference between zonal LMP and the Western Hub LMP. The Western Hub was chosen as the unconstrained reference price because it reasonably represents the unconstrained price of energy in the PJM Mid-Atlantic Region.

Figure 6-1 and Figure 6-2 show some new overall congestion patterns in 2003. The zonal price differential declined for the PENELEC zone. PENELEC is generally not affected by constraints on major interfaces and its congestion has been predominately local, particularly on the Erie West and the Erie South transformers. The installation of additional transformers at Erie West and Erie South alleviated the area's chronic congestion and accounted for most of the nearly $2 per MWh decrease in PENELEC average annual LMP. Baltimore Gas and Electric Company (BGE) and Pepco (PEPCO) zonal price differentials declined. These zones are primarily affected by APS interface constraints and have very little local congestion. Zonal price decreases for the BGE and PEPCO zones are the result of the nearly 406-hour decrease in the occurrence of those constraints. The zonal price differential for the Metropolitan Edison Company (Met-Ed) zone decreased because of a 225-hour decline in the frequency of occurrence of the Jackson and Yorkanna 230/115 transformer constraints in the zone's western area. The DPL zonal price differential also fell, reflecting the benefits of continued transmission investments on the peninsula. Public Service Electric and Gas Company (PSEG) and PECO Energy Company (PECO) were the only zones with price increases relative to the Western Hub between 2002 and 2003. PSEG experienced a 16-fold increase in congestion frequency into northern New Jersey, primarily on the Cedar Grove-Roseland corridor and the Branchburg-Readington circuit. Congestion on these facilities was due primarily to 230 kV transmission outages in northern PSEG. PECO had increased congestion on the Whitpain 500/230 kV transformer and the Plymouth-Whitpain 230 kV line. Much of this was caused by planned transmission outages to support upgrades related to interconnecting new generation resources. Both zones were also affected by increases in Eastern Interface congestion.

Figure 6-2 shows year-to-year differences in zonal congestion, calculated as the difference between zonal LMP and the Western Hub LMP, including the differences in zonal prices between 2003 and 2002, between 2003 and 2001 and between 2002 and 2001. The figure shows that congestion followed the same general geographic pattern in 2003 and 2002.

Figure 6-1 Annual Zonal LMP Differences: Reference to Western Hub

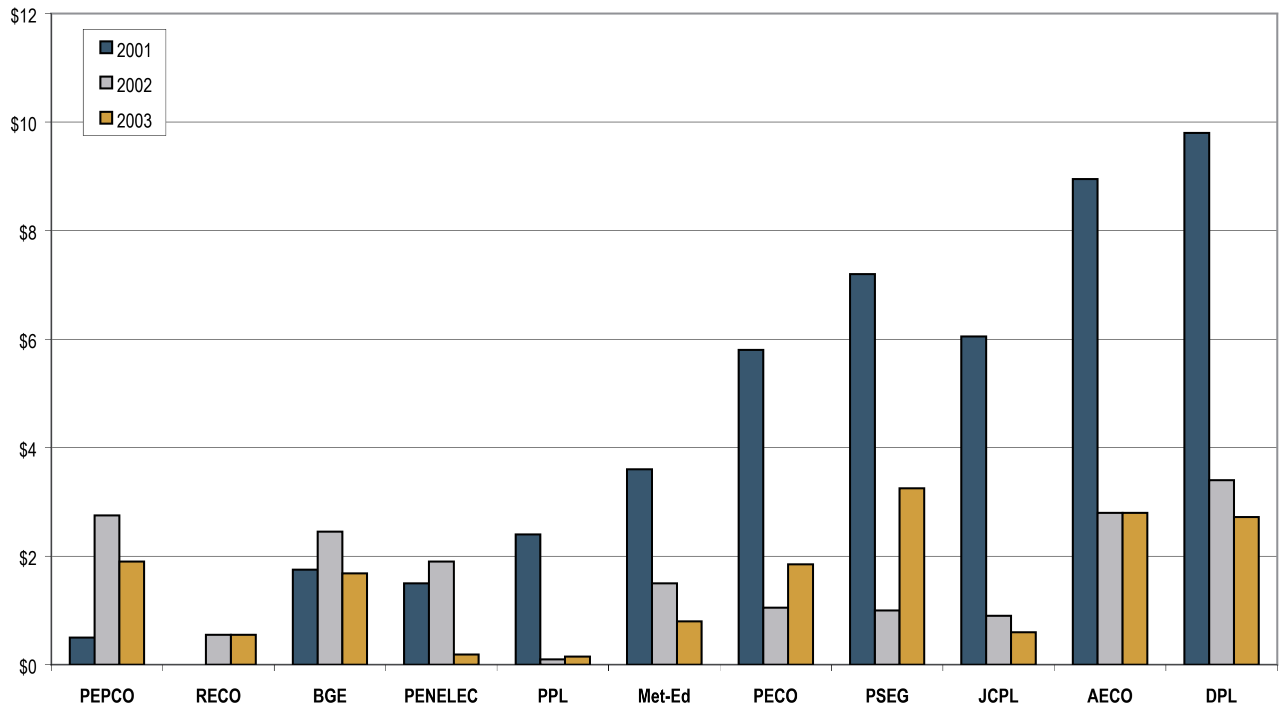
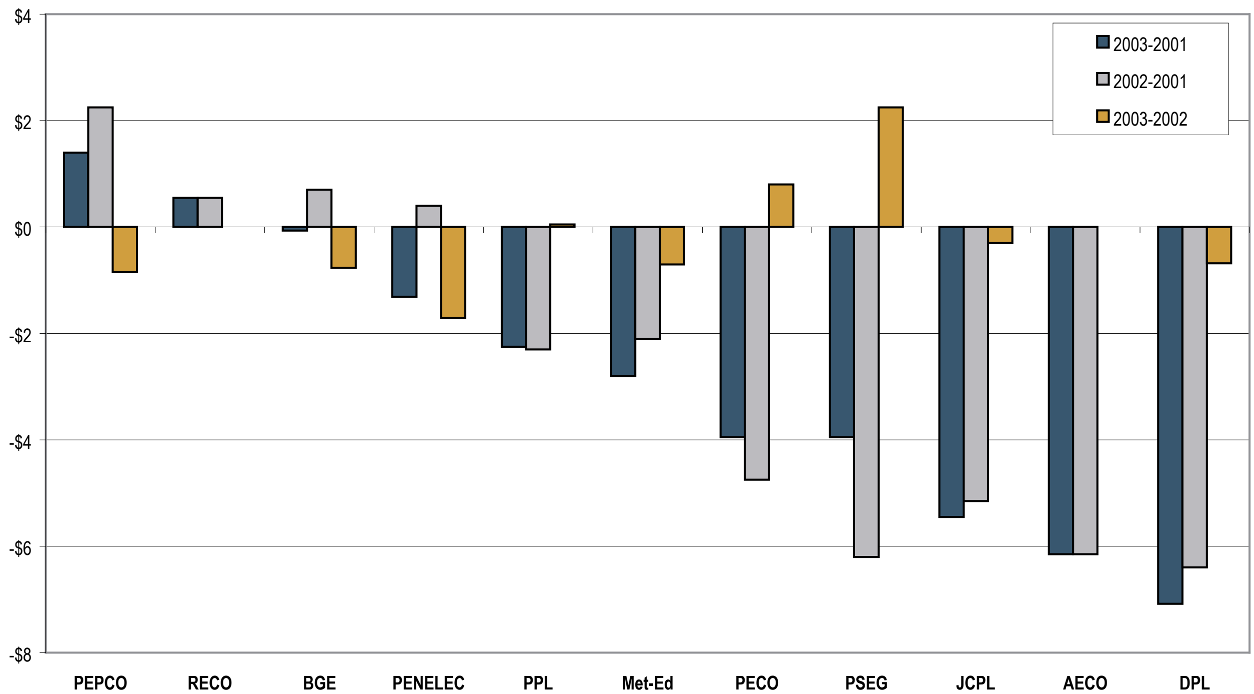


Figure 6-2 Year-to-Year Annual Zonal LMP Differences: Reference to Western Hub



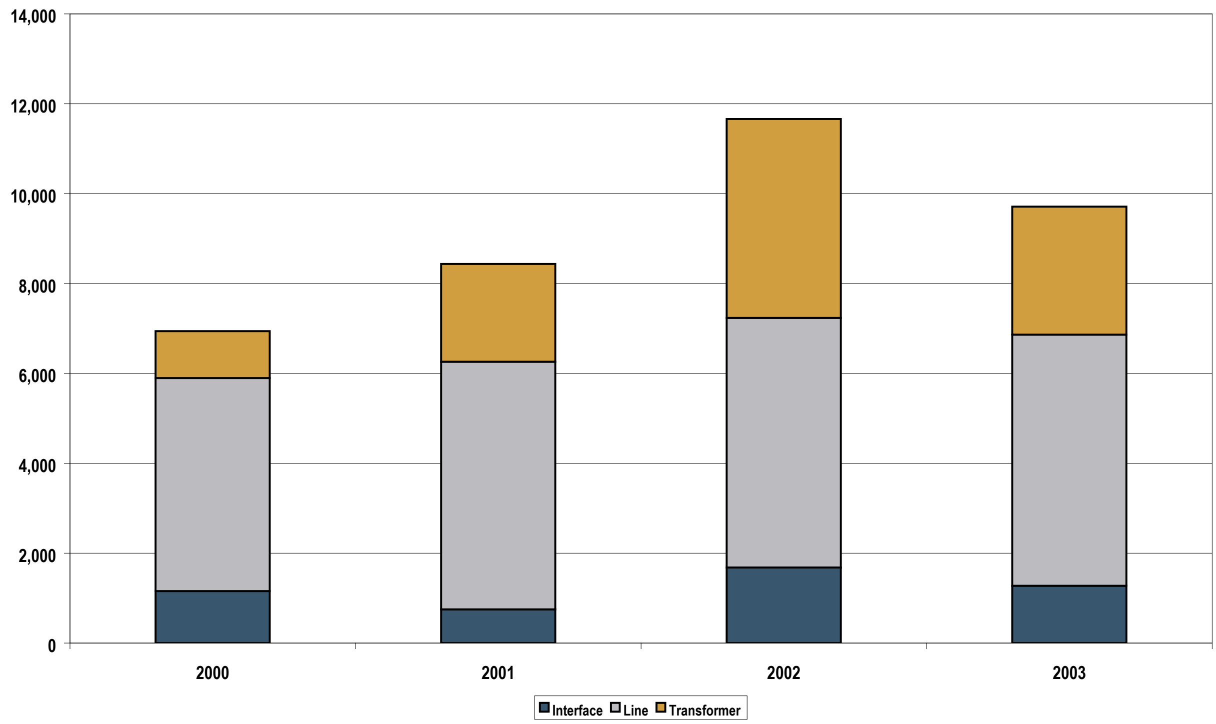
Congested Facilities

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. Each constraint results in a separate congestion event. Constraints are often simultaneous and therefore total congestion event hours can exceed the number of hours in a year. In 2003, there were 9,711 congestion-event hours, a 17 percent decrease from 11,662 in 2002. By contrast, 174 different monitored facilities were constrained during 2003, an increase of 13 facilities over 2002.

Congestion by Facility Type

Figure 6-3 provides congestion-event hour subtotals by facility type: line, transformer and interface. After several consecutive years of increase, the total number of congestion-event hours of operation fell in 2003. The 9,711 total congestion-event hours in 2003 were down by 1,951 hours from the 11,662 congestion-event hours during 2002, about 17 percent. The 2003 decrease in congestion-event hours occurred most notably in hours of interface and transformer constraints which, compared to 2002, were down by 24 percent and 36 percent, respectively.

Figure 6-3 Congestion-Event Hours by Facility Type



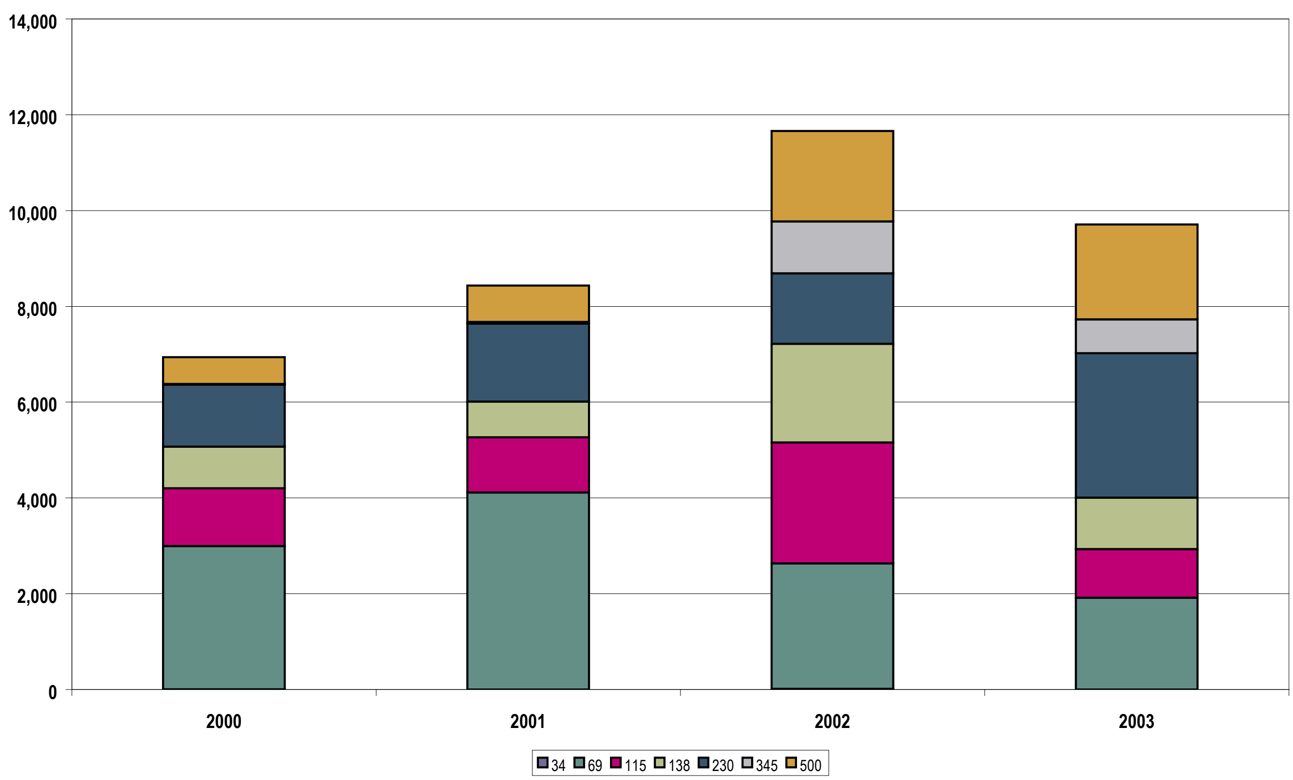
Transformer constraints occurred during 1,580 fewer hours in 2003 than in 2002, with the largest single decrease of 719 congestion-event hours coming from the Erie West 345/115 kV transformer. This resulted from the installation of an additional transformer at Erie West. The replacement of the Cheswold transformer in DPL south resulted in a 71 percent reduction in congestion on this facility over 2002 levels. Similarly, during 2003 the Wylie Ridge 500/345 kV transformer in APS and the Monroe 230/138 kV transformer in Atlantic City Electric Company (AECO) experienced reductions in congested operations of more than 450 congestion-event hours and 300 congestion-event hours, respectively as compared to 2002. The reduction of congestion at Monroe was attributable to the return to service of a Monroe 230/138 kV transformer which had been out since September of 2002.

Interface constraints occurred during 409 fewer congestion-event hours in 2003 than in 2002. The largest improvements were on the Towanda and the PPL Electric Utilities Corporation (PPL) north (PL north) interfaces which occurred for 527 and 185 fewer congestion-event hours, respectively. During 2002, these interfaces had been used to manage congestion on the North Meshoppen transformer and were impacted by area transmission outages. In 2003, upgrades at North Meshoppen removed the need to use these interfaces for constraint control. Congestion was also down significantly on the APS south interface which experienced a 79 percent reduction from 2002 congestion-event hours.

Thermal transmission line limits accounted for 58 percent of all congestion experienced in 2003. The 5,590 hours of transmission line congestion in 2003 constituted a 38-hour increase from 2002 levels. The greatest reductions in thermal line congestion occurred on the PECO Cromby-Moser 230 kV, AECO Lewis-Motts-Cedar 69 kV and DPL Hallwood-Oak Hall 69 kV lines which together experienced 1,000 fewer congestion-event hours than they had in 2002.

Figure 6-4 depicts congestion-event hour subtotals by facility voltage class. Congestion-event hours on 115 kV class facilities were down over 1,500 hours from 2002, with 83 percent of this reduction attributable to the Erie West transformer and Towanda interface in PENELEC. Similarly, congestion-event hours on 138 kV facilities were down by 985 hours, reflecting reductions in APS and DPL as well as on the Monroe 230/138 kV transformer in AECO. By contrast, congestion on 230 kV line facilities increased by over 1,500 hours as compared to 2002, with 32 percent of total 230 kV line congestion during 2003 coming from the Branchburg-Readington and Cedar Grove-Roseland facilities in PSEG.

Figure 6-4 Congestion-Event Hours by Facility Voltage



Constraint Duration

Table 6-4 lists 2003 and 2002 constraints that affected more than 10 percent of PJM load or that were most frequently in effect. It shows changes in constrained hours between the years and the percent of PJM load impacted during each period.[6]

Constraints 1 through 8 are the primary operating interfaces; each affects more than 25 percent of PJM load.[7] For this group, the number of constrained hours decreased from 2,507 to 2,376 hours between 2002 and 2003, a 5 percent drop, impacting an average of 65 percent of PJM load. The PJM Western Region facilities, items number 1, 2, 7 and 8, were constrained 1,688 hours in 2003, a 24 percent decrease in frequency compared to 2002. The PJM Mid-Atlantic Region facilities, items number 3 to 6, were constrained only 688 hours during 2003.

Table 6-4 Constraint Duration Summary

No.	Constraint	% PJM Load Impacted	Congestion-Event Hours			% Annual Hours		
			2003	2002	Change	2003	2002	Change
1	Kammer	95%	304	174	130	3%	1%	2%
2	Wylie Ridge	95%	537	846	-309	6%	7%	-2%
3	West	85%	153	161	-8	2%	1%	0%
4	PJM West 500	80%	248	81	167	3%	1%	2%
5	Central	65%	84	1	83	1%	0%	1%
6	East	50%	203	51	152	2%	0%	2%
7	AP South	25%	32	149	-117	0%	1%	-1%
8	Bedington - Black Oak	25%	815	1044	-229	8%	9%	-1%
9	Doubs	10%	305	235	70	3%	2%	1%
10	Branchburg - Readington	10%	242	10	232	2%	0%	2%
11	Cedar Grove - Roseland	7%	719	73	646	7%	1%	7%
12	Erie South - Erie West	2%	100	166	-66	1%	1%	0%
13	Erie West	2%	182	901	-719	2%	8%	-6%
14	Keeney AT5N	2%	194	82	112	2%	1%	1%
15	Hummelstown - Middletown Jct	2%	280	129	151	3%	1%	2%
16	Edison - Meadow Rd	2%	266	356	-90	3%	3%	0%
17	Cedar	1%	396	166	230	4%	1%	3%
18	Lewis-Motts - Cedar	1%	245	624	-379	3%	5%	-3%
19	Cheswold AT1	1%	77	263	-186	1%	2%	-1%
20	Laurel - Woodstown	1%	597	380	217	6%	3%	3%
21	North Meshoppen	1%	442	221	221	5%	2%	3%
22	Towanda	1%	11	538	-527	0%	5%	-5%
23	Yorkana A	1%	149	186	-37	2%	2%	0%

The Wylie and Kammer transformers impact prices for 95 percent of PJM load, while the Bedington-Black Oak and APS south interfaces both affect prices primarily for PEPCO and BGE load. Doubs 500/138, another APS facility, affects approximately 10 percent of PJM load located in the APS, PEPCO and BGE zones. The Eastern Interface impacts the 48 percent of PJM load located in New Jersey, Delaware and eastern Pennsylvania as well as on Maryland's Eastern Shore. The Central Interface also impacts eastern load, along with an additional 12 percent

6 The constrained hour data presented here use the convention that if congestion occurs for 20 minutes or more in an hour, the hour is considered congested.

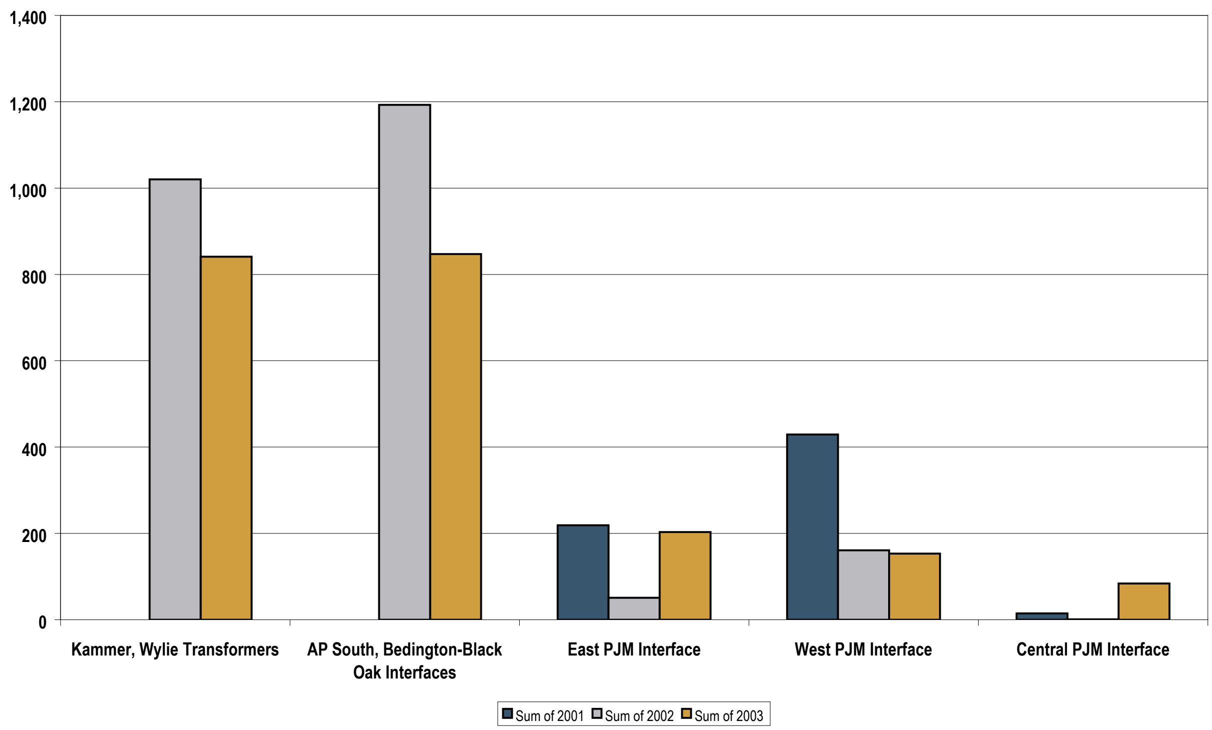
7 Percent of impacted load presented in Table 6-4 is an approximation as determined by distribution factor analysis. Any substation that has a distribution factor greater than 5 percent is deemed to be affected by a constraint.

of PJM load in the PPL and Met-Ed zones located in central Pennsylvania. The Western Interface and western voltage interface constraints affect these areas as well as load in the PENELEC, PEPCO and BGE zones. During 2003, constraint frequency on the main operating interfaces affecting large amounts of PJM load was reduced considerably in the west and increased slightly in the east.

Congestion-Event Hours by Facility

Constraints that affected regions during the period 2001 through 2003 are presented in Figure 6-5. The APS south and the APS Bedington-Black Oak interfaces and the Kammer and Wylie transformers were the most significant regional constraints. The figure shows that constraints affecting flows at the western borders of PJM and at the interface between the PJM Western Region and the PJM Mid-Atlantic Region predominated while constraints internal to the PJM Mid-Atlantic Region occurred substantially less often.

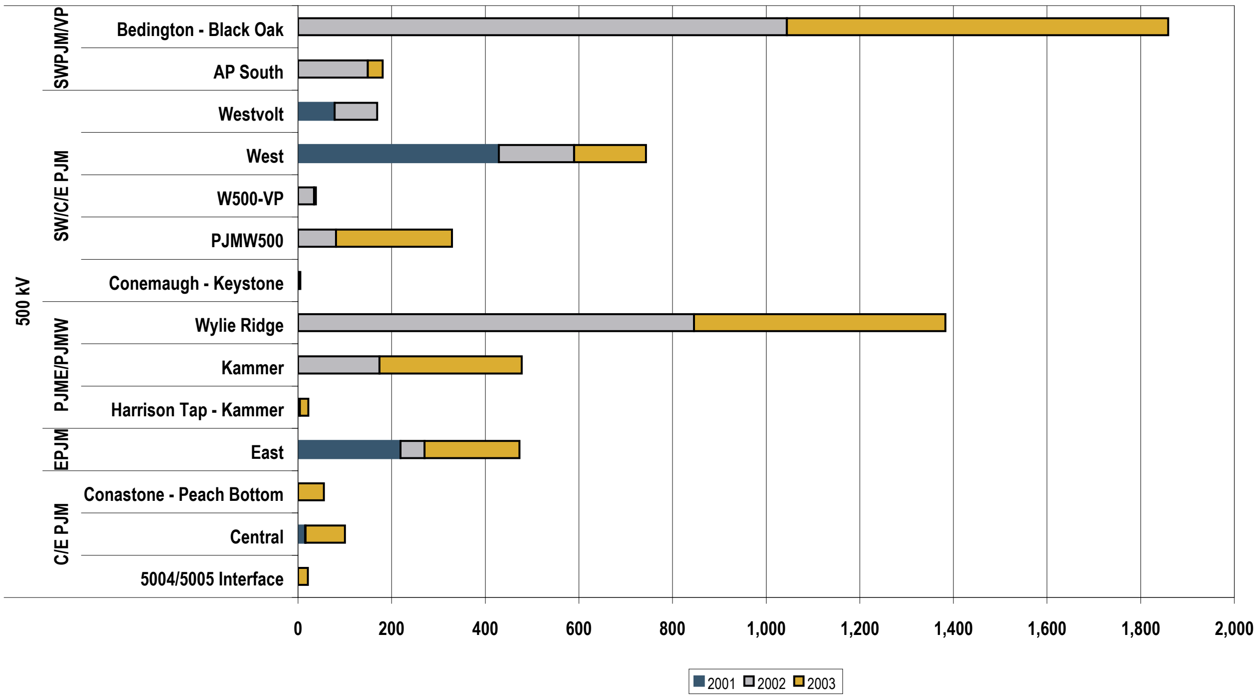
Figure 6-5 Regional Constraints: Sum of Congestion-Event Hours by Facility



Congestion-Event Hours for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Figure 6-6 shows the occurrences of 500 kV constraints by affected region. The PJM Western Region constraints, Wylie Ridge 500/345, Kammer 765/500, Bedington-Black Oak and the APS south interfaces were constrained a combined total of 1,688 congestion-event hours in 2003 as compared to 2,213 hours in 2002, a reduction of 525 hours or about 24 percent.

Figure 6-6 500 kV Zone: Congestion-Event Hours by Facility



Congestion-Event Hours for the Bedington-Black Oak and APS South Interfaces

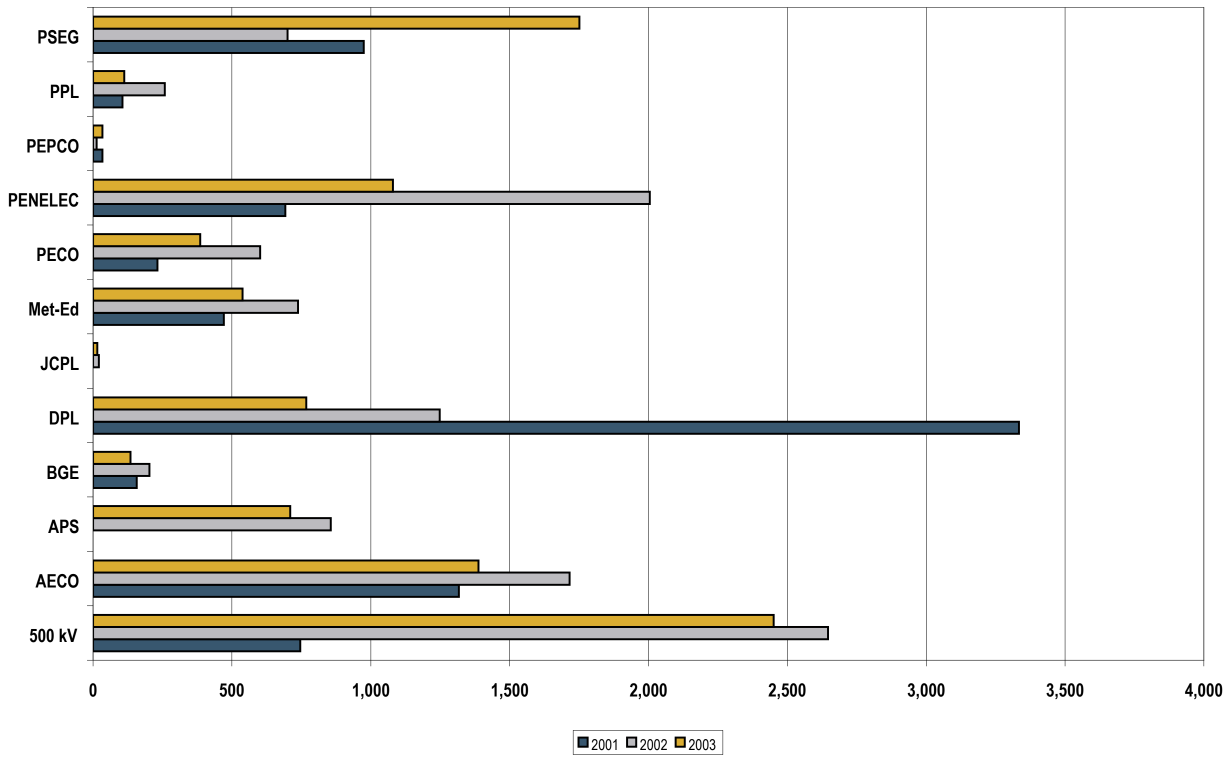
The APS extra-high-voltage (EHV) system is the primary conduit for energy transfers from APS and Midwestern generating resources to southwestern PJM and eastern Virginia load, and, to a lesser extent, to central and eastern PJM. The two APS reactive interface constraints of interest, Bedington-Black Oak and APS south, often restrict west-to-east energy transfers across the APS EHV system. Prior to the incorporation of APS into PJM on April 1, 2002, the primary controlling action for these constraints had been for APS to restrict energy transfers through its system, including transfers from western resources to PJM and VAP. 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.

After APS was integrated into the PJM Market and the redispatch of PJM generation was used to control APS transmission facilities, a significant change in price impacts occurred. Rather than simply restricting relatively low-cost energy transfers, higher cost generating units were dispatched out of merit order (redispatched) in order to serve load in the transmission-constrained areas. As a result, the price of energy in the constrained areas was higher than elsewhere and congestion occurred. Higher LMPs resulted only at those locations directly limited by a constrained facility while lower LMPs occurred elsewhere. PEPCO was most directly affected by these constrained facilities, followed by BGE. The pattern of zonal LMPs reflected this fact as Figure 6-1 shows.

Local Congestion

Constraints within specific zones from 2001 through 2003 are presented in Figure 6-7 which compares the frequency of constraints that occurred in each zone and on the 500 kV system. In 2003 the PSEG zone had over 1,700 constraint hours constituting a 150 percent increase over the previous year. Nearly the entire increase in constrained operation on the PSEG system was attributable to constraints on the Branchburg-Readington 230 kV, Edison-Meadow Road 138 kV and Cedar Grove-Roseland 230 kV facilities. Edison-Meadow Road and Cedar Grove-Roseland congestion was driven largely by generation dispatch patterns in the PSEG zone and transmission outages. Branchburg-Readington congestion was a consequence of 230 kV transmission outages in northern PSEG. The Erie West 345/115 kV transformer and the Towanda interface accounted for the bulk of the 2003 decrease in the PENELEC zone, while the Bedington-Black Oak 500 kV, Wylie Ridge transformer and APS south interface accounted for most of the decrease on the 500 kV system. The DPL zone showed a continued decrease in constrained hours of operation resulting from completion of transmission reinforcements in the southern portion of the territory.

Figure 6-7 Constrained Hours by Zone



Zonal and Subarea Congestion-Event Hours

Figure 6-8 through Figure 6-18 illustrate constraints by transmission zone and subarea. These constraints generally impact energy prices only within the affected zone.

Figure 6-8 illustrates AECO zone constraints. In particular, the very small Cedars subarea consisting of just two 69 kV substations, Motts Farm and Cedar, continued to be frequently constrained, comprising 7 percent of all congestion-event hours in 2003. Also significant was the Laurel-Woodstown 69 kV line in southern New Jersey (SNJ), which increased to 6 percent of all 2003 congestion-event hours. By contrast, the Monroe 230/138 kV transformer, which had been constrained for 454 hours in 2002, experienced no congestion in 2003. The elimination of congestion at Monroe was because of the return to service of a Monroe 230/138 kV transformer which had been out since September of 2002.

Figure 6-8 AECO Zone: Congestion-Event Hours by Facility

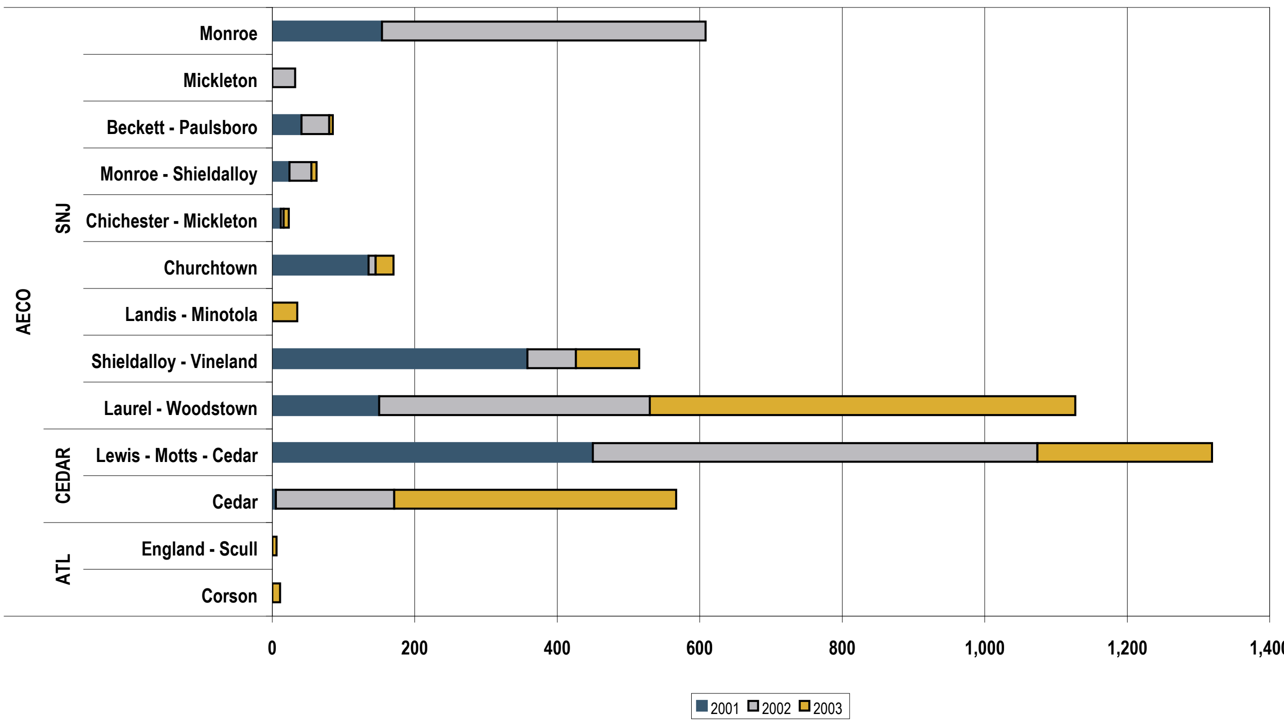


Figure 6-9 illustrates the APS zone constraints. The Doubs 500/230 kV and Wylie Ridge transformers were the most significant constraints. These facilities together represented 9 percent of all congestion-event hours in 2003. The Doubs transformer, affecting approximately 10 percent of PEPCO and APS zonal load, is also impacted by flow on another frequently occurring constraint, Bedington-Black Oak. The Wylie Ridge transformer, located at the westernmost portion of PJM, affects approximately 95 percent of PJM load. This constraint is a frequent cause of transmission loading relief (TLR) events in PJM, as it is difficult to manage solely with PJM generation.

Figure 6-9 APS Zone: Congestion-Event Hours by Facility

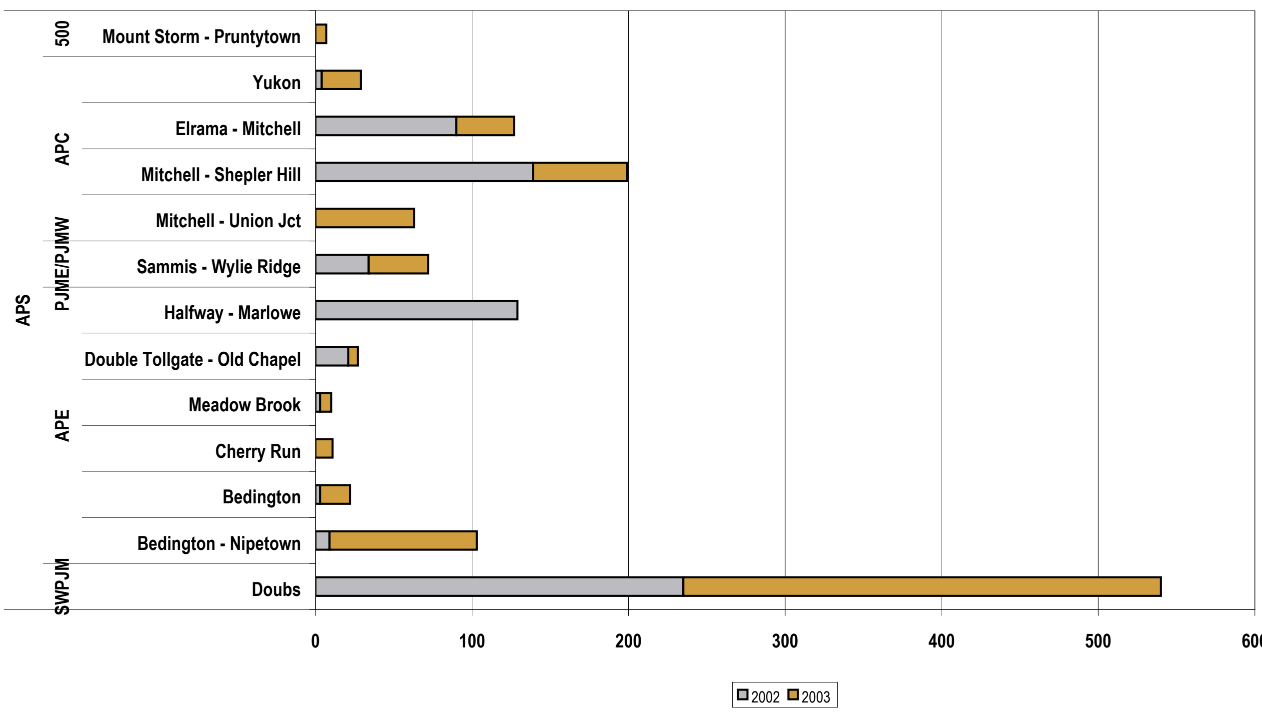


Figure 6-10 illustrates BGE zone constraints. With 142 congestion-event hours, BGE comprised only 1 percent of the total PJM congestion-event hours in 2003. One facility, the Brandon Shores-Riverside 230 kV line, was significantly constrained during 2003. This single facility accounted for 82 percent of total congestion-event hours in the BGE zone. Most of the constraints affected small load pockets or caused bottled generation, such as occurred at Brandon Shores. Bottled generation occurs when local operating constraints prevent full dispatch of economic generation at a plant.

Figure 6-10 BGE Zone: Congestion-Event Hours by Facility

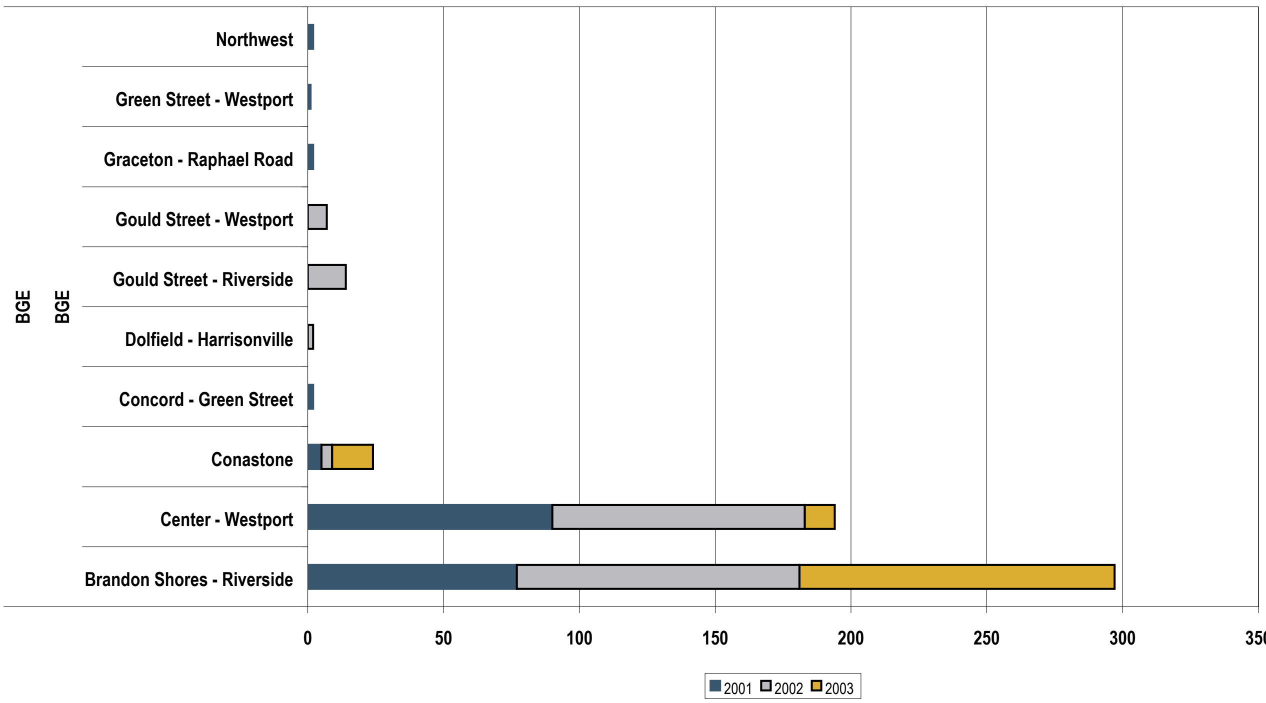


Figure 6-11 illustrates DPL zone constraint occurrences. It shows that the Delmarva Peninsula (DPLS) has experienced numerous constraints over the past three years, but their frequency has declined steadily. The 2003 decline can be directly attributed to the investments in transmission improvements and reinforcements made during the prior four years. During 2003, congestion-event hours in the DPL zone fell 43 percent from 2002 levels. DPL zone congestion-event hours represented 9 percent of total congestion-event hours in PJM. This improvement was driven largely by a reduction in congestion-event hours on the Hallwood-Oak Hall 69 kV line and the Cheswold 138/69 kV transformer. While constraints in DPLS have historically been much more frequent than those in DPLN (northern subarea of DPL) and southeast PJM subareas, the difference in congestion-event hours has decreased significantly.

Figure 6-11 DPL Zone: Constrained Hours by Subarea

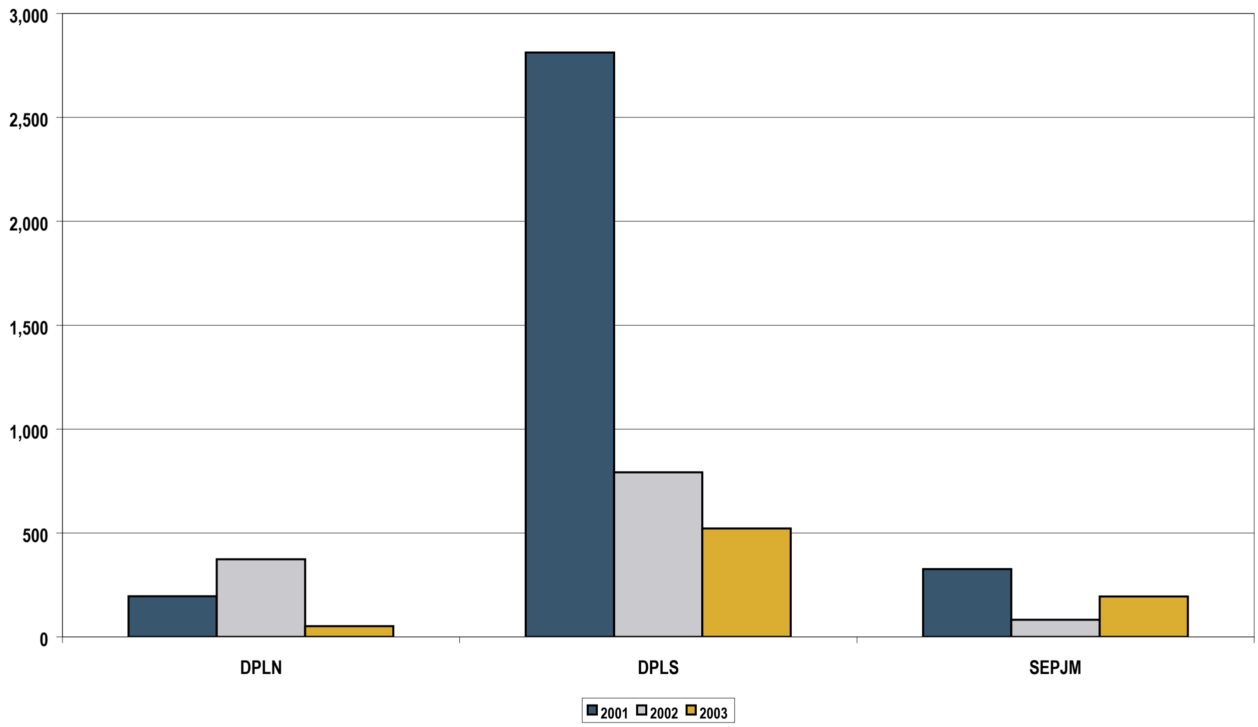


Figure 6-12 illustrates DPLS congestion-event hours by facility. Hallwood-Oak Hall 69 kV and Cheswold 138/69 kV transformer were each constrained over 250 hours in 2002, but were constrained only six and 77 hours respectively in 2003. The reduction at Cheswold is largely attributable to the upgrade of the Cheswold 138/69 kV transformer. The reduction on Hallwood-Oak Hall was caused in large part by the reconfiguration of the points of interconnection of load to the transmission system in the vicinity. In 2003, no facilities were constrained more than 100 hours, representing an improvement over 2002 when four facilities exceeded this threshold.

Figure 6-12 DPLS Subarea of the DPL Zone: Congestion-Event Hours by Facility

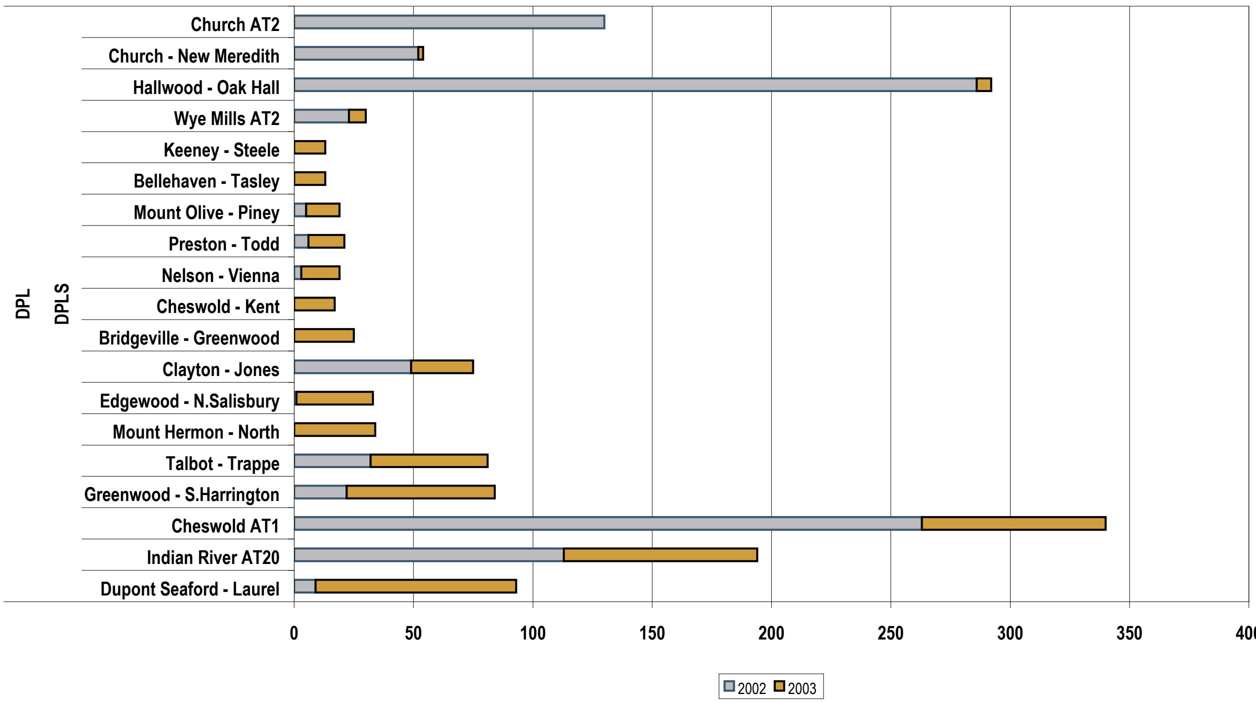
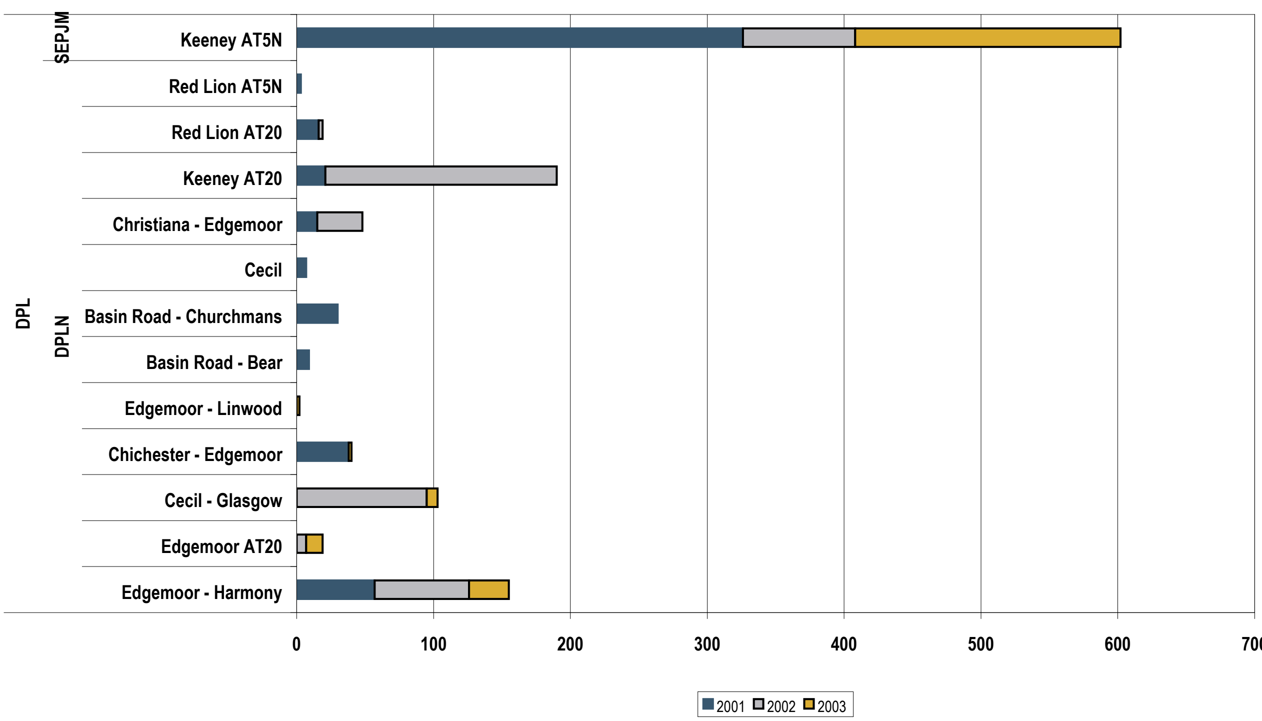


Figure 6-13 presents the same information for the DPLN and southeast PJM (SEPJM) subareas. As shown, during 2002 Keeney 230/138 kV transformer (Keeney AT20) was the most constrained facility in DPLN, with 169 congestion-event hours. The Keeney 230/138 kV transformer was replaced during 2003 and, as a result, experienced no hours of congestion during the year. Keeney 500/230 kV transformer (Keeney AT5N), with 194 congestion-event hours, continued to be the most constrained facility in SEPJM and showed the largest increase in frequency versus 2002. No other facilities were constrained more than 30 hours in DPLN or SEPJM in 2003. Hallwood-Oak Hall with only six congestion-event hours represented the largest decrease in constraint frequency between 2002 and 2003 in the DPL Zone.

Figure 6-13 DPLN and SEPJM Subareas of the DPL Zone: Congestion-Event Hours by Facility



The Jersey Central Power & Light Company zone, for which no figure is included, has experienced little internal transmission congestion, with 21 congestion-event hours in 2002 and 16 congestion-event hours in 2003.

Figure 6-14 illustrates Met-Ed zone constraints. It shows that transmission constraints were significantly lower in the western Met-Ed subarea (MEW), primarily York and Adams Counties, Pennsylvania, where most of the congestion-event hours in this zone had occurred during 2002. The Jackson 230/115 transformer was constrained only 45 hours as compared to 235 hours in 2002. The Yorkanna 230/115 transformer was the only MEW facility constrained more than 100 hours in 2003. Congestion experience on both of these facilities was, in large part, caused by the outage of the Hunterstown 500/230 kV transformer which returned to service in August 2003, following an outage of approximately one year's duration. That outage had the effect of relieving loading on the Jackson 230/115 kV transformer while simultaneously increasing loading on the Yorkanna transformer. The Yorkanna transformer had had 149 congestion-event hours through August 2003, but none during the rest of the year. Similarly, the Jackson transformer had had only seven congestion-event hours during the first seven months of 2003, but then experienced 38 congestion-event hours from August through the end of the year. Southcentral Pennsylvania (SCPA) subarea congestion increased somewhat compared to 2002, constituting 52 percent of total Met-Ed congestion in 2003. As had been true in 2002, the majority of congestion occurred on the Hummelstown-Middletown Junction 115 kV line.

Figure 6-14 Met-Ed Zone: Congestion-Event Hours by Facility

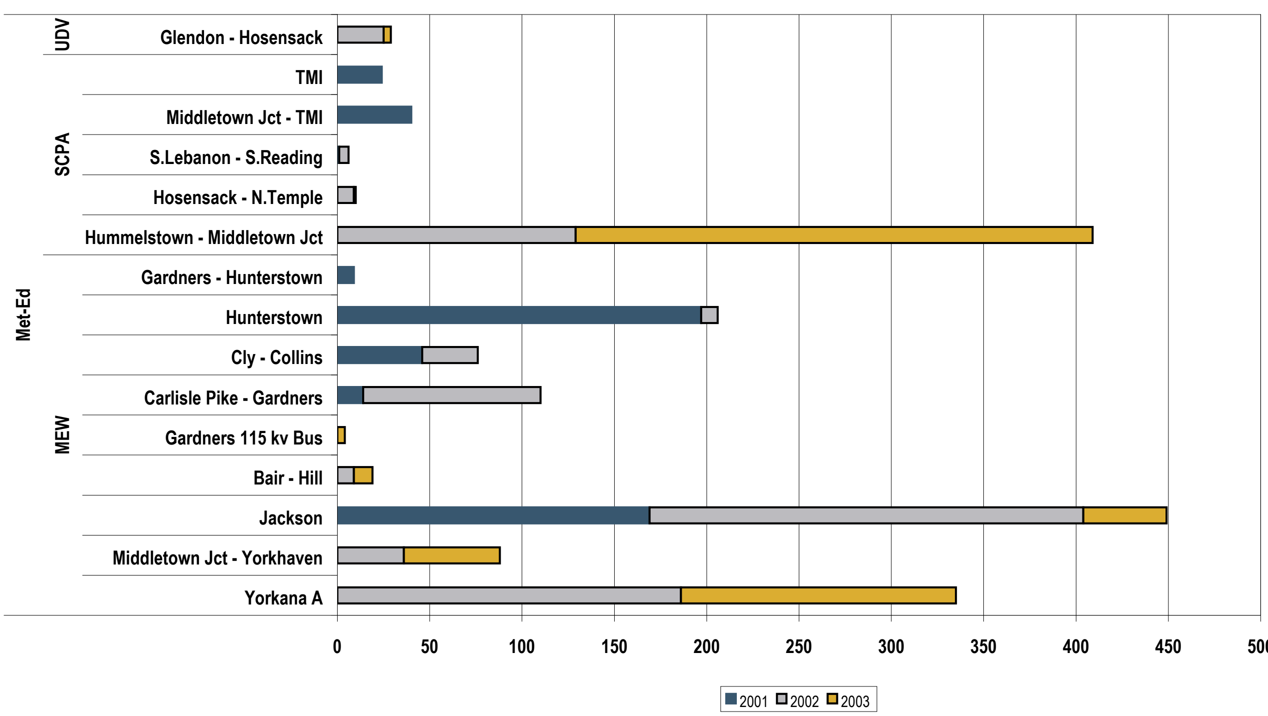


Figure 6-15 illustrates constraints in the PECO zone where in 2003 no facilities were constrained more than 100 hours. The Cromby-Moser 69 kV line, which had experienced 338 congestion-event hours in 2002, saw only 11 congestion-event hours during 2003. Reduced congestion on this facility was attributed to the relocation of load from Moser to Cromby. It was the single largest contributor to the nearly 36 percent reduction in congested hours for the PECO zone. The Plymouth-Whitpain 230 and Whitpain transformer constraints were the only other significant constraints, representing 23 percent and 22 percent respectively of total PECO zone congestion. These constraints were caused largely by planned transmission outages at the Plymouth and Whitpain substations in support of upgrades associated with new generator interconnections.

Figure 6-15 PECO Zone: Congestion-Event Hours by Facility

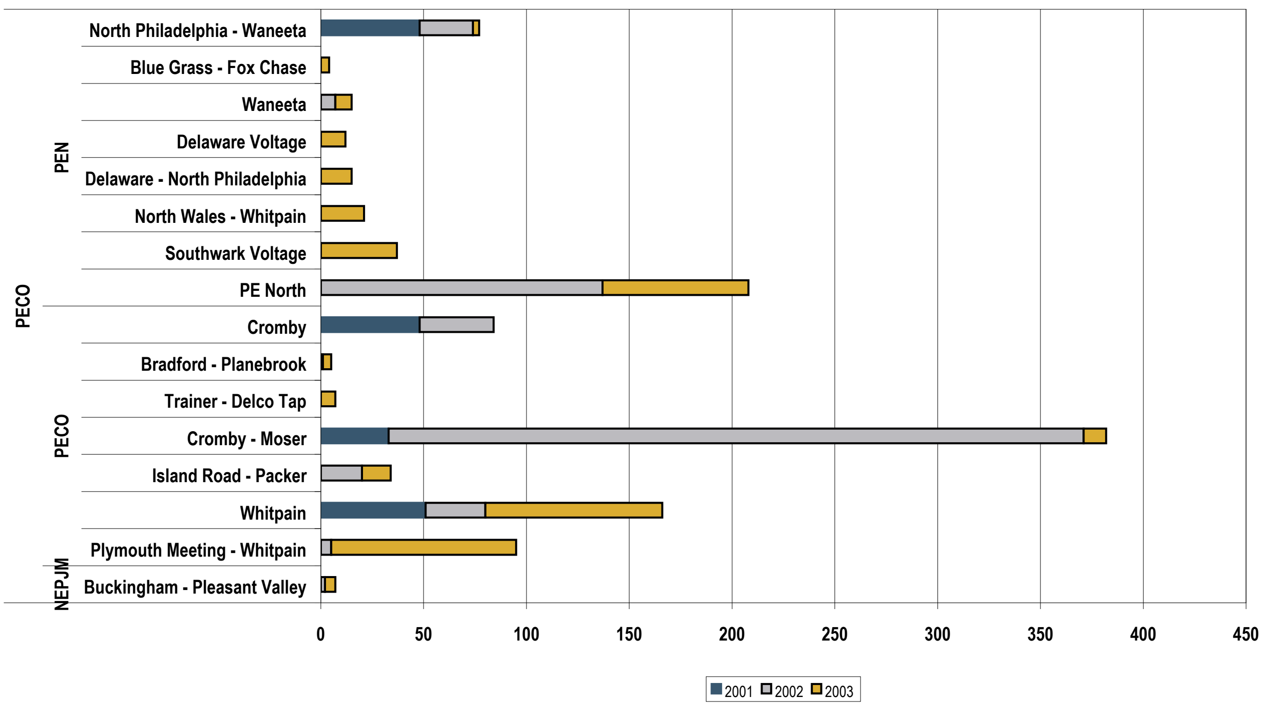
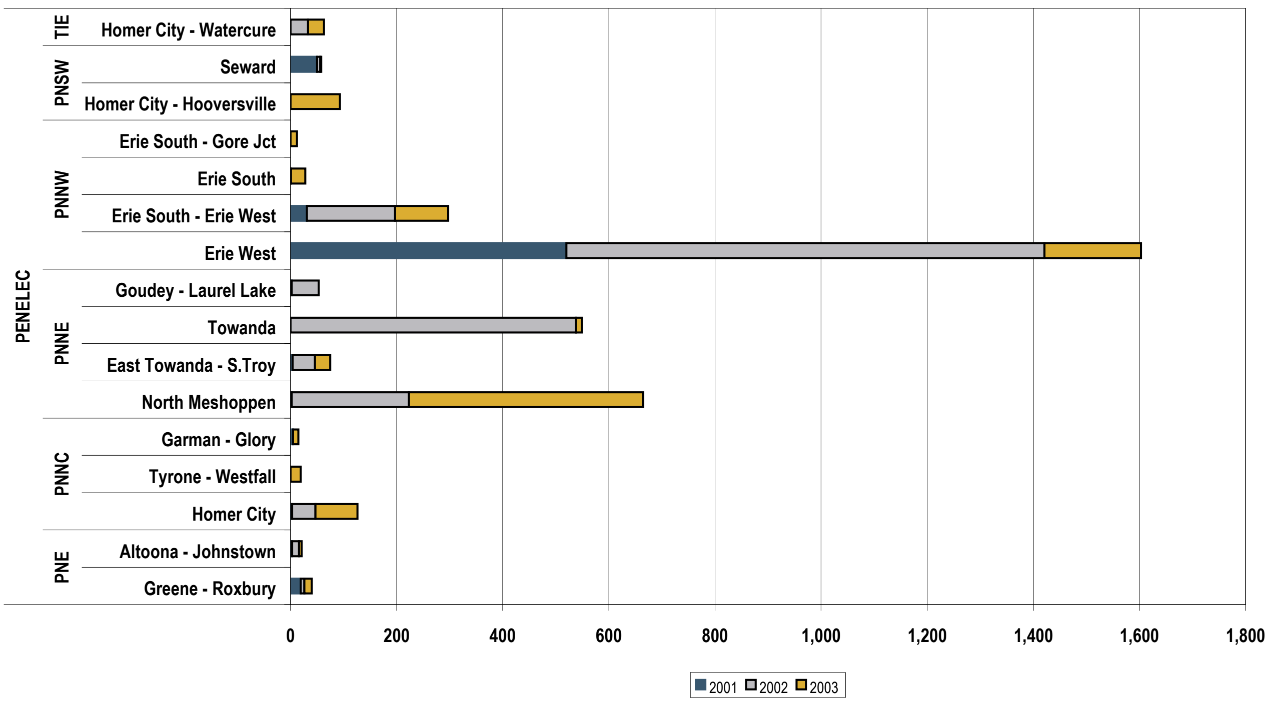


Figure 6-16 illustrates PENELEC zone constraints. It shows that constraints were considerably lower in northwestern PENELEC in 2003. In 2002, the area had experienced nearly triple the frequency in congestion-event hours, with the Erie West 230/115 transformer constrained for 901 hours. In 2003, however, the Erie West transformer, which affects about 2 percent of PJM load, saw only 182 congestion-event hours, a result of a second transformer having been installed at Erie West. The North Meshoppen transformer experienced 442 congestion-event hours in 2003 versus 221 congestion-event hours in 2002, representing nearly 5 percent of the total congestion-event hours in PJM. During 2003, however, a second transformer was installed at North Meshoppen along with series reactors to address this problem. The Towanda reactive interface, which had experienced 538 congestion-event hours in 2002, had 11 congestion-event hours during 2003. During 2002, this interface had been utilized to manage congestion at North Meshoppen, as well as being impacted by area transmission outages. As a result of upgrades at North Meshoppen, this practice was not required during 2003. The Towanda reactive interface constraint affects PJM-NYIS energy transfers through upstate Pennsylvania.

Figure 6-16 PENELEC Zone: Congestion-Event Hours by Facility



The PEPCO zone, for which no figures are included, has experienced very few internal transmission constraints, with 34 congestion-event hours in 2001, 13 congestion-event hours in 2002 and 34 congestion-event hours in 2003.

Figure 6-17 illustrates the frequency of PPL zone constraints. The northern PPL reactive constraint (PL north) appeared during 28 congestion-event hours in 2003 versus 213 congestion-event hours in 2002. During 2002, this interface had been utilized to manage congestion at North Meshoppen, as well as being impacted by area transmission outages. The PPL zone experienced no other significant constraints in 2003.

Figure 6-17 PPL Zone: Congestion-Event Hours by Facility

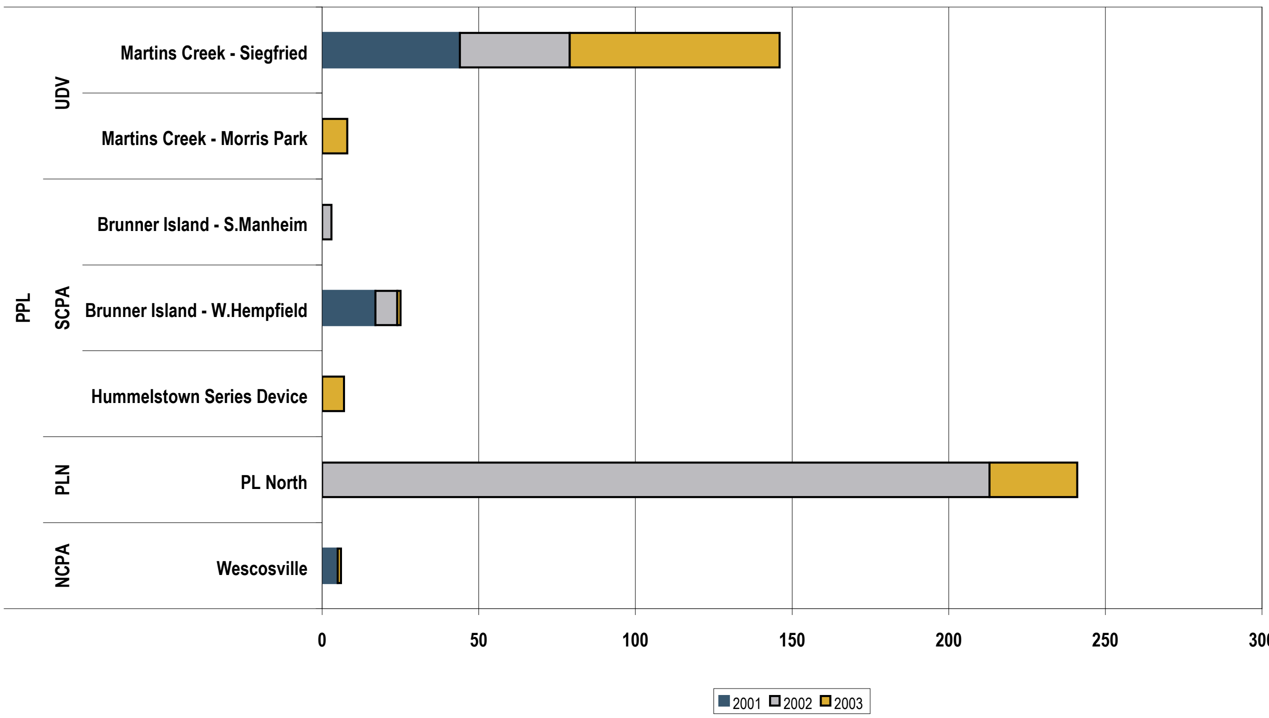


Figure 6-18 illustrates constraint occurrences in the PSEG zone. As shown, constraints in northern PSEG (PSN), primarily Cedar Grove-Roseland 230 which affects approximately one-half of PSEG zone load, were over four times as frequent in 2003 as in 2002. Congestion at Cedar Grove was caused by generation dispatch patterns in northern PSEG and an extended outage of the Linden-Goethals 230 kV line. The Cedar Grove-Roseland 230 kV constraint constituted 7 percent of all congestion-event hours during 2003. Two northcentral PSEG (PSNC) facilities, Branchburg-Readington 230 and Edison-Meadow Road 138 kV, experienced 242 congestion-event hours and 266 congestion-event hours, respectively. Combined, these three facilities accounted for 13 percent of all PJM congestion-event hours for 2003. The increase in congestion on Branchburg-Readington was primarily because of 230 kV transmission outages in the vicinity, while the congestion on Edison-Meadow Road was caused by generation dispatch patterns.

Figure 6-18 PSEG Zone: Congestion-Event Hours by Facility

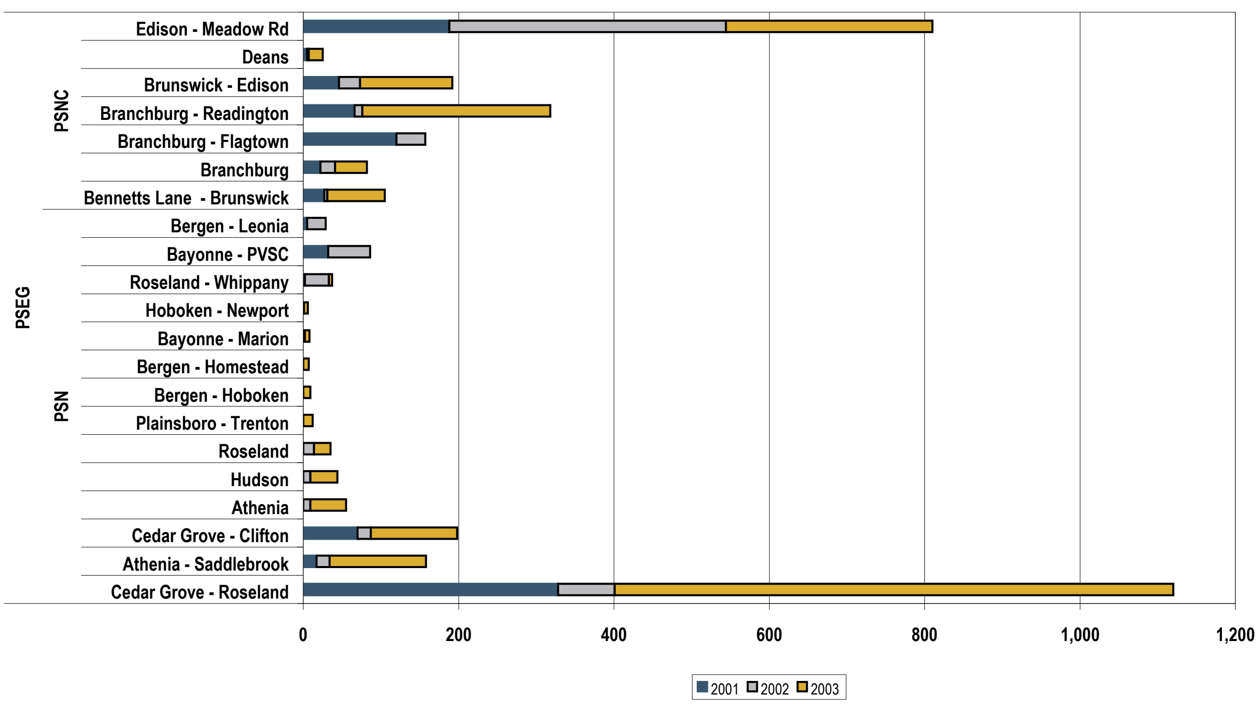


Table 6-5 lists congestion-event hours by facility type and voltage.

Table 6-5 Congestion-Event Hour Summary (by facility type and voltage class)

Type	Voltage (kV)	Congestion-Event Hours				% of Congestion-Event Hours			
		2003	2002	2001	2000	2003	2002	2001	2000
All	All	9,711	11,662	8,435	6,941	100%	100%	100%	100%
	500	1,985	1,888	759	562	20%	16%	9%	8%
	345	705	1,084	38	14	7%	9%	0%	0%
	230	3,016	1,474	1,625	1,294	31%	13%	19%	19%
	138	1,071	2,056	744	869	11%	18%	9%	13%
	115	1,018	2,527	1,154	1,204	10%	22%	14%	17%
	69	1,916	2,619	4,115	2,993	20%	22%	49%	43%
	34	0	14	0	5	0%	0%	0%	0%
Interface	All	1,274	1,683	752	1,159	13%	14%	9%	17%
	500	764	586	747	548	8%	5%	9%	8%
	345	0	5	0	0	0%	0%	0%	0%
	230	103	388	0	240	1%	3%	0%	3%
	115	11	538	0	321	0%	5%	0%	5%
	69	396	166	5	50	4%	1%	0%	1%
Line	All	5,590	5,552	5,507	4,737	58%	48%	65%	68%
	500	917	1,128	12	14	9%	10%	0%	0%
	345	168	233	38	14	2%	2%	0%	0%
	230	2,104	658	1,164	912	22%	6%	14%	13%
	138	815	1,163	408	773	8%	10%	5%	11%
	115	187	413	214	348	2%	4%	3%	5%
	69	1,399	1,943	3,671	2,671	14%	17%	44%	38%
	34	0	14	0	5	0%	0%	0%	0%
Transformer	All	2,847	4,427	2,176	1,045	29%	38%	26%	15%
	500	304	174	0	0	3%	1%	0%	0%
	345	537	846	0	0	6%	7%	0%	0%
	230	809	428	461	142	8%	4%	5%	2%
	138	256	893	336	96	3%	8%	4%	1%
	115	820	1,576	940	535	8%	14%	11%	8%
	69	121	510	439	272	1%	4%	5%	4%

Congestion Management Pilot Program

The PJM Transmission Operations Manual states:

> *The PJM 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.*[8]

A pilot program was conducted during the period July 11 through September 31, 2003 to measure the effectiveness of a proposed contingency management policy at reducing the incidence of off-cost operations. Under this pilot, several facilities were selected in the Conectiv territory whose operations would be managed to new 36-minute ratings. No off-cost operations would be initiated on behalf of these facilities unless the calculated post contingency flow would exceed these new short-term ratings.

PJM issued its findings on the program's results on October 1, 2003. Its analysis indicated 272 hours of avoided real-time, off-cost operations because of the new thermal emergency limits supplied under the pilot program. Avoided hours were calculated based on the amount of time the post contingency flow was above the old long-term emergency (LTE) or short-term emergency (STE) ratings in place prior to the pilot program, but below the new 36-minute ratings supplied under this program. The Laurel-Woodstown constraint alone contributed 167 of the 272 total hours of avoided off-cost operation. Total savings were calculated based on these avoided hours.

No trippings were associated with the pilot constraints, consistent with a prerequisite analysis indicating a historical probability of less than 0.05 percent of contingent facility trippings.

Through an open stakeholder process, PJM is currently facilitating discussion as to whether to institutionalize the congestion management procedures tested in the pilot. A decision as to the future of this program is expected in early 2004.

8 See PJM Manual, "Transmission Operations [M03]," page 27.

Section 7 – Financial Transmission and Auction Revenue Rights

In PJM, Financial Transmission Rights (FTRs) have been available to firm point-to-point and network transmission customers as a hedge against congestion charges. These firm transmission customers have had access to FTRs because they pay the costs of the transmission network that makes firm energy delivery possible. Individual firm transmission customers have received FTRs to the extent that they are consistent both with the physical capability of the transmission system and with the other firm transmission customers' requests for FTRs.

On June 1, 2003, PJM replaced the direct allocation of FTRs with an allocation of Auction Revenue Rights (ARRs) coupled with an Annual FTR Auction. The allocation of ARRs is identical to the previous process for allocating FTRs, but the value of the ARRs is based on a separate Annual FTR Auction. The ARR rules also provide that firm transmission customers are not required to take the market-based ARR value and may instead opt to take the underlying FTR via a process termed self-scheduling. ARRs provide holders with a revenue stream based on the locational price differences between ARR sinks and sources that result from the Annual FTR Auction.[1]

The Annual FTR Auction permits market participants to bid for the FTRs and thus provides a market-based determination of both ARR and FTR value. New FTR auction products were offered for the 2003/2004 planning period. These include annual and monthly FTR options, which are FTRs that, unlike traditional FTR obligations, can never be a financial liability. Additionally, 24-hour FTRs were added to the product portfolio consisting of on-peak and off-peak FTRs.

In addition to the Annual FTR Auction, PJM continues to run Monthly FTR Auctions designed to permit bilateral sales of FTRs and to permit participants to buy excess system FTRs.

Both ARRs and FTRs are financial instruments that entitle the holder to receive revenues (or pay charges) based on nodal price differences. The value of the ARRs is based on differences in nodal prices across selected paths that result from the Annual FTR Auction. The price of FTRs is determined by the auction results. The value of the FTR hedge is a function of the nodal prices in the hourly Day-Ahead Energy Market. ARR and FTR holders do not need to deliver energy to receive ARR or FTR credits, and neither instrument represents a right to the physical delivery of power. Both can, however, protect load-serving entities (LSEs) and other market participants from uncertain costs caused by transmission congestion in the PJM Day-Ahead Market. Market participants can also hedge against real-time congestion by matching real-time energy schedules with day-ahead energy schedules.

Overview

Market Structure

- **Supply and Demand.** During the 2003 ARR allocation process, 28,933 MW of ARRs were allocated, or 73 percent, out of 39,888 MW requested. Twenty percent, or 56,743 out of 279,898 MW, of buy bids for annual FTR obligations cleared. Of the cleared FTR buy bids, 25 percent were self-scheduled FTRs. Only 1 percent, or 24,175 out of 2,196,421 MW, of all buy bids for FTR options cleared. During the 2003 Monthly FTR Auctions, as in 2002, bid volume exceeded offer volume by nearly a 10:1 ratio, averaging approximately 55,000 versus 5,800 MW per month.

1 ARR values are functions of the implicit nodal price differences determined in the FTR auction since the final, optimal FTRs sold in the auction may not be identical to the ARRs.

Market Performance

- **Price.** In 2003, the $9,547 per MW-year paid for 24-hour annual FTR obligations was substantially higher than the $2,945 per MW-year paid for on-peak annual FTRs and the $1,357 per MW-year prices paid for off-peak FTRs. The overall average $3,235 per MW-year price paid for all annual FTR obligations was higher than the $1,989 per MW-year price paid for options. Prices in the 2003 Monthly FTR Auctions dropped from $369 per MW-month in 2002 to $195 MW-month in 2003, with most of the decrease occurring during the months after the June implementation of the Annual FTR Auction.

- **Volume.** Under the ARR allocation process, 28,933 MW of ARRs were allocated during the period. Introduction of the Annual FTR Auction in 2003 substantially increased the amount of long-term FTRs held by market participants. Some 32,907 MW of 24-hour, long-term FTRs were awarded, including 5,871 MW of FTRs into the Allegheny Power (APS) zone. Net of APS FTRs, these 27,036 MW of 24-hour FTRs slightly exceeded the 26,813 MW of PJM Mid-Atlantic Region FTRs held by market participants in 2002. However, an additional 28,026 MW of on-peak and 25,843 MW of off-peak FTRs were also awarded in 2003, more than doubling outstanding FTRs compared to 2002. Monthly FTR auction volume increased by 80 percent from 6,390 MW cleared in 2002 to 11,506 MW in 2003. Average monthly auction volume peaked in February 2003, with 23,188 MW of on-peak and off-peak FTRs exchanged.

- **Revenue.** During 2003, the Annual FTR Auction produced $332.8 million of net revenue, while the Monthly FTR Auction generated $22.0 million of net revenue. Average monthly auction revenue grew from $350,000 per month in 2000 to over $600,000 per month in 2001, $1.2 million per month in 2002 and $1.8 million per month in 2003.

- **Congestion Hedge.** Firm transmission customers that were allocated ARRs had $177 million of ARR credits and self-scheduled FTR target allocations and $199 million of congestion costs, a congestion hedging ratio of 89 percent. The ARR hedging shortfall was largely confined to two zones. If firm transmission customers had retained the allocated ARRs without self-scheduling FTRs, the ARRs would not have provided adequate revenue to hedge congestion fully. FTRs were paid $499 million of congestion credits against $521 million of FTR target allocations, a congestion hedging ratio of 96 percent.

A review of the operation of the 2003 FTR auction process indicates that the results were competitive and succeeded in increasing FTR access. Long-term FTR volume increased significantly via the new Annual FTR Auction, and there was a steady increase in MW of cleared FTRs in the ongoing Monthly FTR Auction. The introduction of rules explicitly providing for ARRs to track retail load shifting removes a potential barrier to competition.

Auction Revenue Rights

ARRs are annual financial instruments entitling their holders to a portion of annual FTR auction revenues. ARRs are allocated to network service and firm point-to-point transmission customers. ARRs provide the holder with revenue based on the results of the Annual FTR Auction. Annual ARR revenue is credited monthly to ARR holders. As load shifts among LSEs, ARRs are automatically reassigned to follow the load.

The ARR Approach

Evolution of the Annual ARR Allocation Process

The 2003/2004 Process

ARRs are allocated to network service and long-term, firm point-to-point transmission customers because they pay the costs of the transmission network. Network service customers can request ARRs from their designated capacity resources to their aggregate load, while firm point-to-point transmission customers can request ARRs between their designated sources and sinks. Network customers with load in new transmission zones can elect to receive direct allocation FTRs instead of ARRs during a two-year transition period. The ARRs and FTRs are awarded based on simultaneous feasibility test results. If the requested set of ARRs and FTRs is not simultaneously feasible, customers are assigned a *pro rata* share of transmission capability in inverse proportion to the impact of their requested ARRs or FTRs on the binding constraints.

The 2004/2005 Process

Effective for the 2004/2005 planning period, ARRs and direct allocation FTRs (to firm transmission customers in new transmission zones) will be allocated in a two-stage process:

- **Stage 1.** During stage 1, network customers will be able to obtain ARRs from resources that historically served load in the zone or load aggregate, to their aggregate load. Network customers will not be required to designate capacity resources as the source for the ARR. Direct allocation customers will also be able to obtain FTRs during this stage. As before, ARRs and FTRs will be awarded based on simultaneous feasibility test results. If the requested set of ARRs and FTRs is not simultaneously feasible, customers will be assigned a *pro rata* share of transmission capability into each transmission or load aggregation zone based on their percentage of zonal peak load and in inverse proportion to their impact on binding constraints. ARRs will not be available to long-term, firm point-to-point customers in this stage.

- **Stage 2.** During this multiround allocation, network and direct allocation customers will be able to obtain ARRs and FTRs from any generator, hub, external interface, or load zone to their aggregate load that remains unallocated after the first stage. ARRs will also be available to long-term, firm point-to-point customers in this stage.

Optional ARR Self-Scheduling

Under ARR rules, firm transmission customers can apply to receive ARRs. If they do so, the value of the ARRs, and thus the value of the congestion hedge, is determined entirely by the results of the Annual FTR Auction. This value could be greater than, less than or equal to the actual congestion that occurs on the selected path and thus could provide a hedge with varying levels of completeness.

Firm transmission customers can also opt to retain the underlying FTRs associated with the ARRs they are assigned. The value of the hedge associated with the underlying FTR is the actual day-ahead congestion on the selected path rather than a value determined in the Annual FTR Auction. Such customers can elect to receive the underlying FTRs directly via a process termed self-scheduling. By self-scheduling ARRs as price-taking buy bids in the Annual FTR Auction, customers with ARRs receive FTRs along their ARR path. ARR holders are guaranteed that they will receive their requested FTRs and such self-scheduled bids will be ineligible to set the auction price. Self-scheduling is permitted only for 24-hour FTRs.

A market participant desiring to self-schedule must initiate the process in the first round of the Annual FTR Auction. One-fourth of the self-scheduled FTR MW will then clear in this and each of the three successive rounds. 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 via holding the corresponding ARR and is left with the FTR as a hedge. The FTR hedges the holder against actual day-ahead market congestion whereas the ARR hedges the holder against congestion through revenues received based on the market value of the FTR.

ARR Target Allocations and Credits

ARR target allocations are revenue that ARR holders should receive and are equal to the product of the ARR path price as determined in the Annual FTR Auction and the ARR MW. ARR credits are revenue actually received by ARR holders. If the net annual FTR auction revenue exceeds the sum of ARR target allocations, then ARR credits will equal target allocations for all ARRs. If net annual FTR auction revenue is less than the sum of ARR target allocations, then ARR credits will be less than target allocations for all ARRs, and credits will be paid at less than full value. Monthly FTR auction revenue also is used to satisfy ARR target allocations. If the Annual FTR Auction has insufficient revenue, monthly auction revenue will flow to ARR holders. ARR holders cannot receive credits in excess of their target allocations. Any FTR auction revenue in excess of ARR target allocations is used to offset any FTR congestion credit deficiencies.

Automatic ARR Reassignment for Retail Load Switching

If load switches among LSEs during the planning year, ARRs within a given transmission or load aggregation zone are automatically reassigned. Reassignment of ARRs from an LSE occurs only if that LSE loses load in a zone and has ARRs with net positive economic value. LSEs losing load also lose a proportional share of the associated positively valued ARRs. Likewise, those gaining load are allocated a proportional share of the positively valued ARRs within the zone based on the shifted load. This rule ensures that the hedge against congestion follows load, thereby removing a potential barrier to competition among LSEs. It also assures that an LSE cannot assign poor ARR choices (i.e., those with net negative value) to other LSEs, thus preventing the potential exercise of an anticompetitive strategy.

Initial ARR Results

Market Structure

During the 2003/2004 annual ARR allocation process, 28,933 MW of ARRs were allocated to firm transmission customers out of 39,888 MW requested. The PJM Western Region is under the two-year transition period, and 5,871 MW of direct allocation FTRs into the PJM Western Region were also allocated in the ARR allocation process. The Bedington-Black Oak, Central and Eastern Interface constraints prevented full allocation of desired ARRs. For comparison, 26,813 MW of annual FTRs were allocated in 2002.

Market Performance

Volume

Allocated ARRs

One measure of the effectiveness of ARRs as a hedge against congestion is a comparison between ARR revenue and self-scheduled FTR revenue. Summary data are shown in Table 7-1 for the seven-month period from June 1, to December 31, 2003.

Table 7-1 ARR and Self-Scheduled FTR Portfolio Congestion Hedging: 2003

Sink	Day-Ahead Congestion ($1,000)	Revenue ($1,000)			Hedge Provided by		
		ARR Credits	Self-Scheduled FTR Target Allocations	Total	ARRs	Self-Scheduled FTRs	ARRs & Self-Scheduled FTRs
PENELEC	($5,388)	$1,646	$202	$1,848	100%	100%	100%
FE	($333)	$0	($333)	($333)	100%	100%	100%
JCPL	$927	$153	$574	$727	17%	62%	78%
Western Hub	$1,243	$0	$1,243	$1,243	0%	100%	100%
Met-Ed	$7,836	$172	$7,630	$7,802	2%	97%	100%
AECO	$9,168	$3,010	$4,876	$7,886	33%	53%	86%
PPL	$12,543	$2,931	$10,131	$13,062	23%	81%	104%
DPL	$20,437	$13,788	$4,918	$18,706	67%	24%	92%
BGE	$21,379	$14,144	$8,667	$22,812	66%	41%	107%
PEPCO	$37,837	$20,120	$19,061	$39,181	53%	50%	104%
PECO	$42,979	$7,270	$26,848	$34,118	17%	62%	79%
PSEG	$50,727	$28,309	$2,081	$30,390	56%	4%	60%
Totals:	$199,356	$91,544	$85,899	$177,442	46%	43%	89%

Note: PENELEC zone FE interface have negative day-ahead congestion and are 100 percent hedged by definition.

Between June 1, 2003, and December 31, 2003, congestion costs across the 28,933 MW of allocated ARR transmission paths were $199.4 million. These costs are calculated as the product of the hourly day-ahead ARR sink and source locational marginal price (LMP) differences and the ARR MW. As has been indicated, 13,986 MW of ARRs were converted into FTRs through the self-scheduling option, with 14,947 MW remaining as ARRs. The ARRs that were not self-scheduled provided $91.5 million of ARR credits, representing a hedge of 46 percent of the congestion incurred, while the self-scheduled FTRs provided $85.9 million of revenue, or a 43 percent hedge. Total congestion hedged by both was $177.4 million, or 89 percent of the $199.4 million total congestion incurred across the selected ARRs.

Figure 7-1 graphically depicts total congestion as well as ARR, FTR and total revenue across the ARR paths into each transmission zone and to each external interface. It shows that seven of 12 transmission zones and interfaces were fully hedged by the selected combination of ARRs and self-scheduled FTRs. The Pennsylvania Electric Company (PENELEC) zone and the FirstEnergy Corp. interface actually experienced negative congestion and would have been fully hedged without ARRs or FTRs. Nonetheless, the ARRs provided additional revenue, enhancing the net revenue position of PENELEC load, although the FTRs resulted in a financial liability. Three zones, Jersey Central Power & Light Company (JCPL), Atlantic City Electric Company (AECO) and Delmarva Power & Light Company (DPL), were almost fully hedged, with ARRs covering $27.3 of $30.5 million of congestion across the selected ARRs. Two remaining transmission zones, PECO Energy Company (PECO) and Public Service Electric and Gas Company (PSEG), received $64.5 million in payments against $93.7 million of congestion.

Figure 7-1 ARR and Self-Scheduled FTR Portfolio Congestion Hedging: 2003

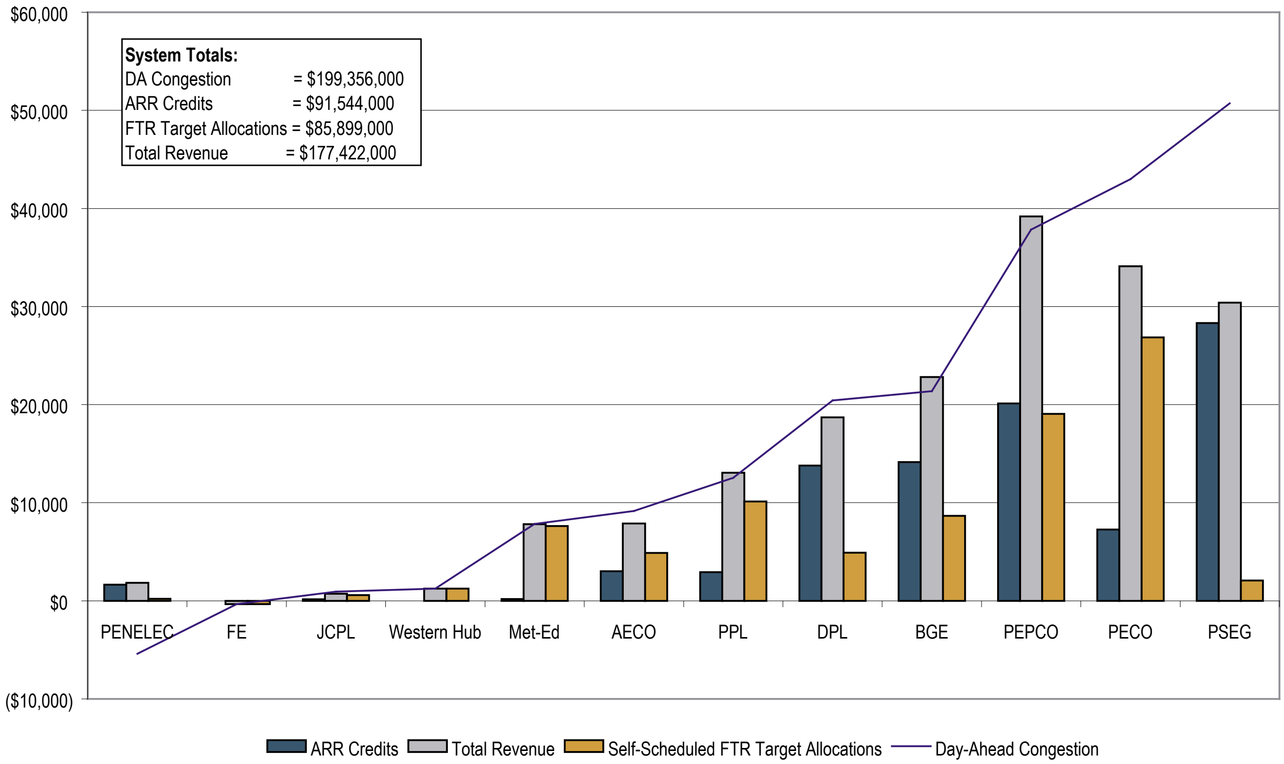


Table 7-1 also presents the extent to which each transmission zone and interface sinks were hedged as a percentage. Most were hedged above 85 percent, with the exceptions of the PSEG (60 percent), PECO (79 percent) and JCPL (78 percent) zones.[2]

Although not explicitly reported in the tables, 14 of 19 load aggregation zones were fully hedged against the congestion incurred between their generating resources and load, with $91 million of combined revenue versus $81 million of congestion. It is worth noting that the smaller load aggregation zones were well-hedged for the period by ARRs and self-scheduled FTRs, with $8.5 million of combined revenue against $8.3 million of congestion among them.

Self-Scheduling

During the 2003 Annual FTR Auction, 13,986 of 28,933 MW, or about 48 percent, of ARRs were self-scheduled. Self-scheduled ARRs constituted 51 percent of the 24-hour FTRs awarded in that auction and provided 48 percent of its revenue.

Reassigned

During the seven-month period, June 1, 2003 through December 31, 2003, 10,824 MW of ARRs were reassigned to various LSEs. These constituted 37 percent of all ARRs. Approximately 85 percent (9,180 MW) of the reassigned ARRs and 74 percent of reassigned ARR credits were associated with load in New Jersey zones. Most load switching occurred on August 1, 2003, when 7,582 MW of New Jersey load changed suppliers under the New Jersey Basic Generation Service (BGS) auction.

Revenue Adequacy

Table 7-2 presents summary data on ARR revenue adequacy. It shows that 34 market participants were awarded 28,933 MW of ARRs effective during the 2003/2004 planning period. Based on settled prices in the Annual FTR Auction, these ARRs had target allocations of $311.2 million. As the table indicates, the Annual FTR Auction generated $332.8 million of net revenue, fully satisfying ARR target allocations with a $21.5 million surplus.

2 Although the hedge for JCPL zone was only 78 percent, there were few ARRs into the zone, and the absolute revenue deficiency was very small.

Table 7-2 ARR Revenue Adequacy: 2003 and 2003/2004

Item	2003	2003/2004
Annual FTR Auction Net Revenue	N/A	$332,762,792
ARR Target Allocations	N/A	$311,245,088
ARR Credits	N/A	$311,245,088
Annual FTR Auction Revenue Surplus	$12,551,994	$21,517,704
Monthly FTR Auction Revenue*	$10,711,011	$10,711,010
Surplus Auction Revenue**	$23,263,005	$23,263,004

An additional $10.7 million of net auction revenue was collected in the June through December 2003 Monthly FTR Auctions. When added to the $12.5 million of excess revenue prorated to 2003 from the 2003/2004 Annual FTR Auction, this amount provided a total of $23.2 million used to offset congestion credit deficiencies in 2003.

Hedging Results

These conclusions are based on data for only the first seven months of the 12-month period of the ARR allocation and the encompassed Monthly FTR Auctions. In aggregate during 2003, $199.4 million of congestion occurred across the ARRs, with $177.4 million of ARR and self-scheduled FTR target allocations, an overall hedging ratio of 89 percent. The ARR hedging shortfall was largely confined to two zones.

Hypothetical Hedging Strategies

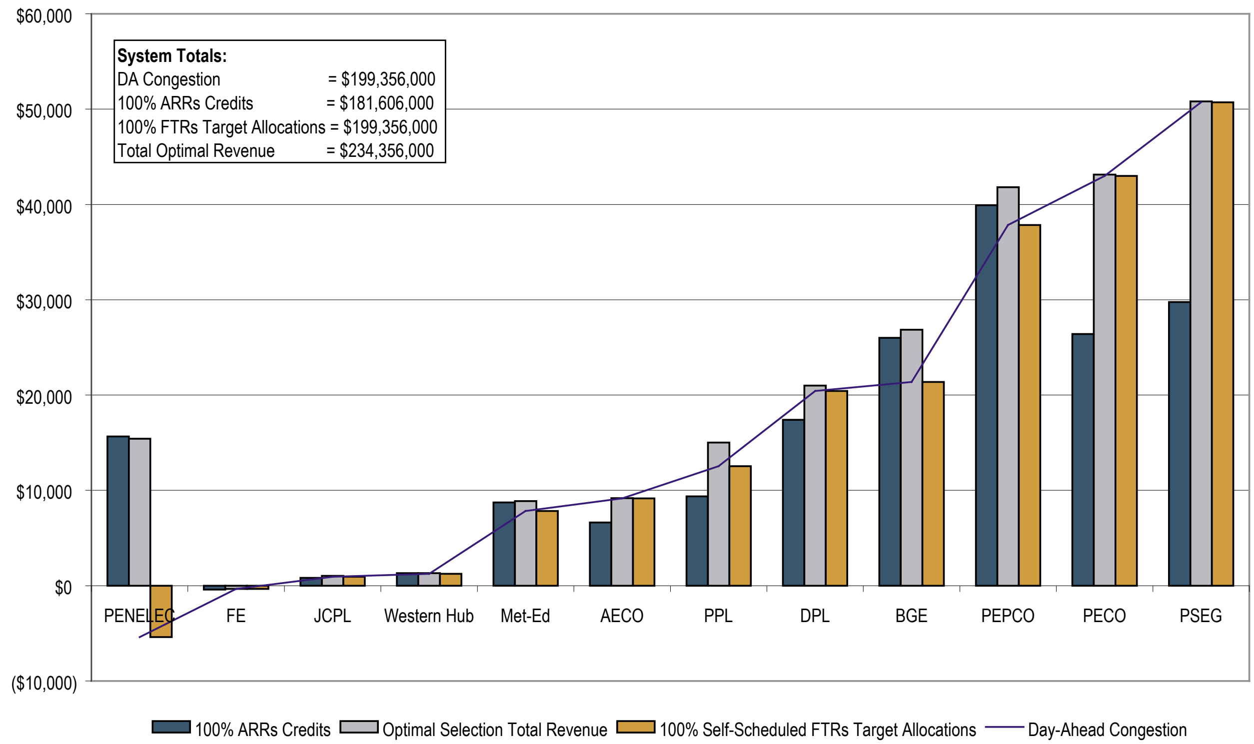
In order to evaluate the consequences of the actual choice of ARRs and self-scheduled FTRs, a range of hedging approaches is compared. The value of the hedge provided by the actual selection of ARRs and self-scheduled FTRs against congestion across the set of selected ARRs is compared to a selection of 100 percent ARRs, a selection of 100 percent FTRs and an optimal mix of ARRs and FTRs. Table 7-3 and Figure 7-2 illustrate these results.

Table 7-3 Optimal ARR and Self-Scheduled FTR Portfolio Congestion Hedging: 2003

Sink	Day-Ahead Congestion ($1,000)	Revenue ($1,000)			Hedge Provided by		
		100% ARRs Credits	100% Self-Scheduled FTRs Target Allocations	Optimal ARR/FTR Selection Total Revenue	100% ARRs Credits	100% Self-Scheduled FTRs Target Allocations	Optimal ARR/FTR Selection
PENELEC	($5,388)	$15,656	($5,388)	$15,428	100%	100%	100%
FE	($333)	($398)	($333)	($333)	120%	100%	100%
JCPL	$927	$820	$927	$1,021	88%	100%	110%
Western Hub	$1,243	$1,320	$1,243	$1,320	106%	100%	106%
Met-Ed	$7,836	$8,738	$7,836	$8,885	112%	100%	113%
AECO	$9,168	$6,637	$9,168	$9,194	72%	100%	100%
PPL	$12,543	$9,362	$12,543	$15,015	75%	100%	120%
DPL	$20,437	$17,406	$20,437	$20,999	85%	100%	103%
BGE	$21,379	$25,994	$21,379	$26,853	122%	100%	126%
PEPCO	$37,837	$39,912	$37,837	$41,802	105%	100%	110%
PECO	$42,979	$26,406	$42,979	$43,133	61%	100%	100%
PSEG	$50,727	$29,753	$50,727	$50,811	59%	100%	100%
Totals:	**$199,356**	**$181,606**	**$199,356**	**$234,128**	**91%**	**100%**	**117%**

Note: PENELEC zone FE interface have negative day-ahead congestion and are 100 percent hedged by definition.

Figure 7-2 Optimal ARR and Self-Scheduled FTR Portfolio Congestion Hedging: 2003



One strategy would be to obtain ARRs, but not self-schedule any FTRs. If all ARR holders had held their ARRs, they would have received $181.6 million of ARR credits against $199.4 million of congestion, resulting in a 91 percent hedge.[3]

Another strategy would be to obtain ARRs and self-schedule all ARRs as FTRs, an approach which would hedge all congestion less any FTR funding deficiencies. Such a strategy would have hedged $191.4 million, or 96 percent, of congestion. As the data show, firm transmission customers in some zones would have received more revenue by employing the all ARR strategy [PENELEC, Metropolitan Edison Company (Met-Ed), Baltimore Gas and Electric Company (BGE) and Pepco (PEPCO) zones]; others would have benefited more by implementing the all FTR strategy [AECO, PPL Electric Utilities Corporation (PPL), DPL, PECO and PSEG zones]. Zones benefiting from the former strategy are all located west of the Eastern Interface; with the exception of the PPL zone, those benefiting from the latter strategy are all located east of the Eastern Interface.

The final strategy would be to obtain an optimally selected combination of allocated ARRs and self-scheduled FTRs. While this strategy could not be implemented in exactly this manner because it includes an after the fact evaluation based on perfect choices, it does represent the maximum value of a hedge based on ARRs and self-scheduled FTRs. The optimal mix of ARRs and self-scheduled FTRs was created by selecting the self-scheduled FTR whenever the cost of congestion across an ARR path was greater than the ARR revenue received. If the congestion across an ARR path was less than the ARR revenue, then the ARR was selected.

In 2003, the optimally selected combination of ARRs and self-scheduled FTRs would have netted approximately $139.6 million from the FTRs and $94.5 million from ARRs. The combined revenue of $234.1 million would have more than covered the $199.4 million of congestion with a surplus of $34.7 million.

3 Each of the comparisons of hedging strategies must recognize that the actual results of the FTR auctions are, in part, a function of the actual strategies pursued.

Financial Transmission Rights

On June 1, 2003, PJM introduced 24-hour FTRs into the Annual and Monthly FTR Auctions. Because FTRs may be feasible in either the on-peak or off-peak period but not over all 24 hours, these different contracts provide market participants with more flexibility in obtaining FTRs.

FTR options were also introduced on June 1, 2003. A traditional FTR obligation is a directional instrument that provides revenue, either positive or negative, based on the difference between source and sink LMPs. An FTR option, on the other hand, is a directional instrument that provides only positive revenue. Its value becomes zero when the difference between the source and sink LMPs would otherwise result in negative revenue to the holder. As a result of the fact that the feasibility test is more restrictive for options than for obligations (the system must be feasible both with and without the option being exercised), FTR options are generally priced higher than obligations.

Market Structure

Before 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 market participants can participate in the Annual FTR Auction. Furthermore, auction market participants are free to request long-term 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, the universe of FTRs available in the Annual FTR Auction has expanded.

FTR Auctions

Annual FTRs are allocated in a four-round auction:

- **Round 1.** ARR holders wishing to self-schedule their ARRs as FTRs must initiate the self-scheduling process in the first round of the Annual FTR Auction. One-quarter of each self-scheduled FTR clears as a 24-hour FTR in this and each of the subsequent three rounds. The self-scheduled FTR must have the same source and sink as the ARR. There is no bid price associated with self-scheduled FTRs, and such self-scheduled FTRs are guaranteed to clear as price-taking FTR obligations. Market participants bid for FTRs between any source and sink. These may include 24-hour, on-peak or off-peak FTR obligations or options. Locational prices are determined by maximizing the bid-based value of FTRs cleared. Auction participation is not restricted to any class of customers, and any market participant may bid for available FTRs.

- **Rounds 2-4.** During each of the subsequent three rounds, one-quarter of the self-scheduled FTRs clear as price-taking FTR obligations. Market participants bid for FTRs, and locational prices are determined by maximizing the bid-based value of FTRs cleared. FTRs purchased in earlier rounds may be offered for sale in subsequent rounds.

In the Monthly FTR Auctions, market participants can bid for FTRs consistent with residual system transmission capability. Monthly FTRs are allocated in a single-round auction. Market participants bid for FTRs between any source and sink. These may be 24-hour, on-peak, or off-peak FTR obligations or options. Locational prices are determined by maximizing the bid-based value of FTRs cleared. Participation in the auction is not restricted to any class of customers, and any market participant may bid for available FTRs.

Annual FTR Auction Results

During 2003, participants purchased 80,928 MW of 24-hour, on-peak and off-peak annual FTR obligations and options at a cost of $345.7 million. There were 13,986 MW of 24-hour, self-scheduled FTRs purchased at a cost of $159.2 million, accounting for 48 percent of the net annual FTR auction revenue. Such self-scheduled ARRs constituted 51 percent of the 24-hour FTRs and 17 percent of all FTRs awarded in the Annual FTR Auction. These data are presented on an annual basis in Table 7-4. Prior data on performance of ARRs and FTRs as a hedge applied only to the seven-month period beginning June 1, 2003, and ending December 31, 2003.

Table 7-4 Annual FTR Auction Price, Volume and Revenue

Transaction	Volume (MW)	Price ($/MW-year)	Cost ($)
Buy	66,941	$2,785	$186,451,454
Self-Scheduled	13,986	$11,389	$159,293,918
Buy + Self-Scheduled	80,928	$4,272	$345,745,372
Sell	1,574	$8,246	($12,982,580)
Net	82,502	$4,033	$332,762,792

The $11,389 per MW-year average price of self-scheduled FTRs was considerably higher than the $2,785 per MW-year price paid for those FTRs which were purchased rather than self-scheduled. This is because all self-scheduled FTRs clear as price-takers, while regular buy bids clear only if their bid exceeds the path price. Indeed, only 3 percent of regular buy bids cleared. Even though self-scheduled FTRs accounted for only 17 percent of FTRs purchased, they accounted for 46 percent of paid FTR revenue. Market participants sold 1,574 MW of FTRs for $13.0 million at an average price of $8,246 per MW-year.

FTR options accounted for 30 percent of cleared volume and 14 percent of auction revenue. Only 1 percent of all option bids and offers cleared compared to 20 percent of FTR obligations.

Table 7-5 Mean FTRs by Term

Year	Annual 24-hour (MW)	Monthly On-Peak (MW)	Total (MW)	Annual 24-hour (%Total)	Monthly On-Peak (%Total)	Secondary (MW)	Secondary (% Total)
2003	58,741	8,579	67,320	87%	13%	1,352	2%
2002	26,813	6,805	33,618	80%	20%	7,173	21%
2001	25,272	3,616	28,888	87%	13%	3,333	12%
2000	30,941	3,547	34,488	90%	10%	4,438	13%
1999	31,888	1,097	32,985	97%	3%	3,805	12%

Table 7-5 presents the FTRs outstanding at the end of 2003. Annual 24-hour FTRs represent the sum of network and point-to-point FTRs for 1999 to 2002, and the sum of all annual 24-hour FTRs in 2003, including APS. The 58,741 MW of 2003 24-hour FTRs is comprised of 32,907 MW of 24-hour FTRs plus 25,834 MW of 24-hour equivalent FTRs.[4] As shown, the introduction of the Annual FTR Auction substantially increased the amount of long-term FTRs. In 2003, 24-hour, long-term FTRs increased from the historical average of 28,729 MW to 58,741. It must be noted that 5,871 MW of the 30,012 MW increase is directly attributable to the inclusion of the APS zone. Regardless, long-term FTRs have increased by 24,141 MW outside of APS, a substantial increase.

4 There are 28,026 MW of on-peak and 25,834 MW of off-peak annual FTRs that are combined into 25,834 MW of 24-hour equivalent FTRs for comparison purposes.

Monthly on-peak FTRs are the average of the on-peak FTRs awarded in the monthly auction. Compared to historical data, monthly auction volume more than doubled during the same period.

Figure 7-3 shows the 10 FTRs that generated the greatest amount of annual auction revenue grouped by the FTR destination (sink). FTRs to these sinks accounts for $309 million or 90 percent of all revenue paid and comprised 44 percent of the 82,505 MW of FTRs purchased. These sinks are located throughout the PJM system. For reporting ease, the PEPCO zone also includes PEPCO's D.C., MD and Southern Maryland Electric Cooperative (SMECO) aggregates. The DPL zone includes the Delmarva north (DPLN), Delmarva south (DPLS) and Old Dominion Electric Cooperative (ODEC) aggregates.

Figure 7-3 Highest Revenue Producing Annual FTR Auction Sinks Purchased

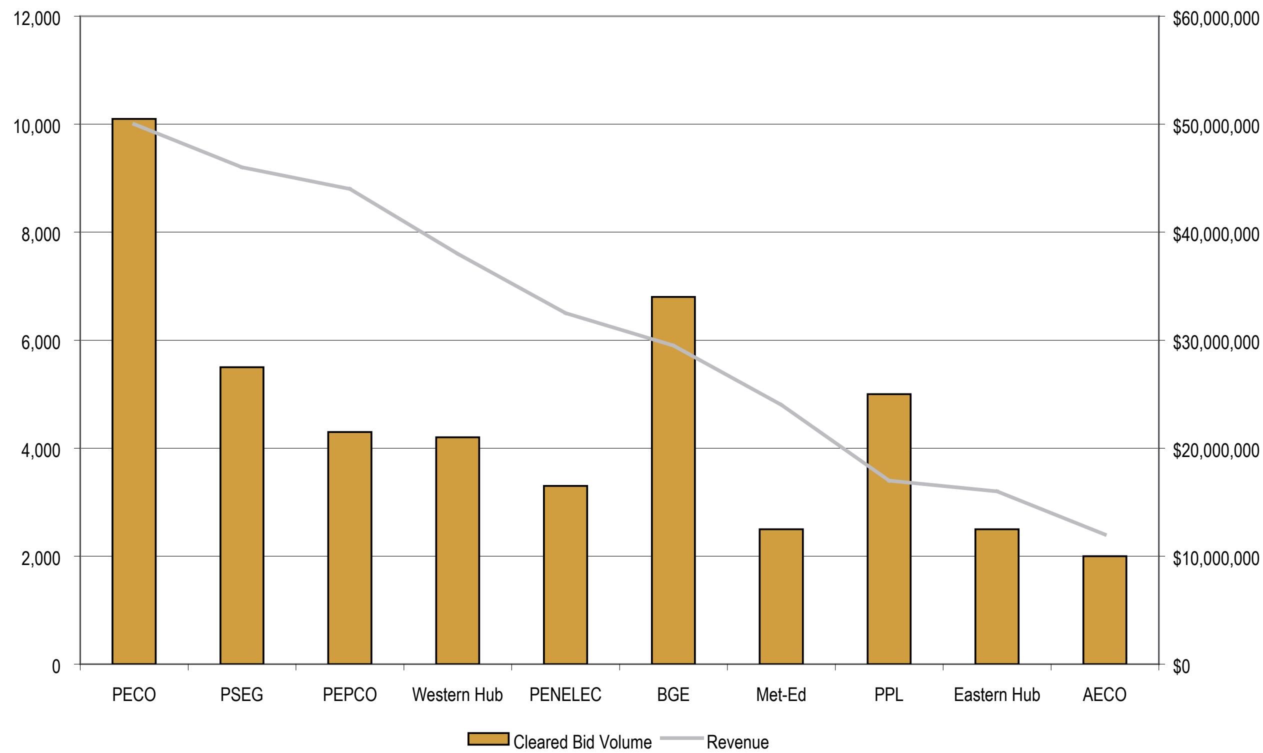
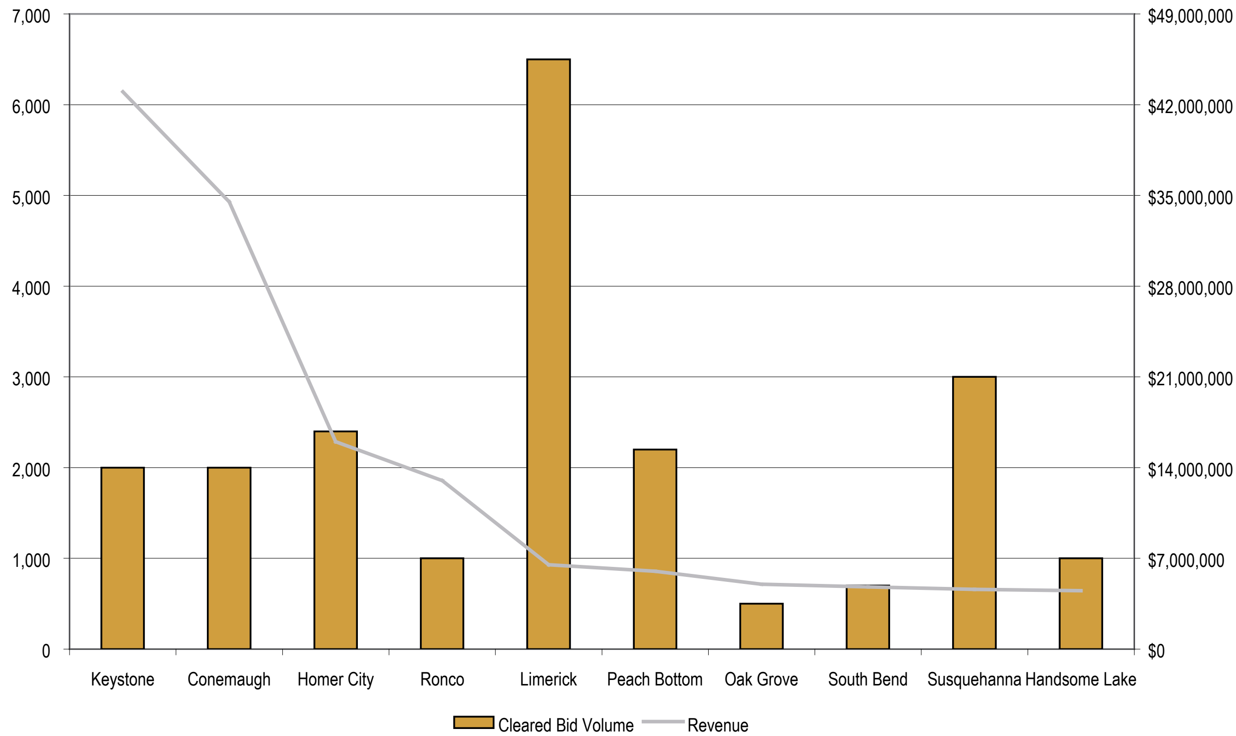


Figure 7-4 shows the 10 FTRs generating the greatest amount of annual auction revenue grouped by the FTR origin (source). FTRs from these sources accounted for $138 million or 40 percent of all revenue paid and comprised 30 percent of all FTRs purchased in the annual auction. Keystone, Conemaugh, Homer City located in northwestern part of the PJM system together accounted for 27 percent of revenue and 2 percent of volume.

Figure 7-4 Highest Revenue Producing Annual FTR Auction Sources Purchased



Monthly FTR Auction Results

Figure 7-5 Cleared Monthly FTR Auction Volume and Net Revenue

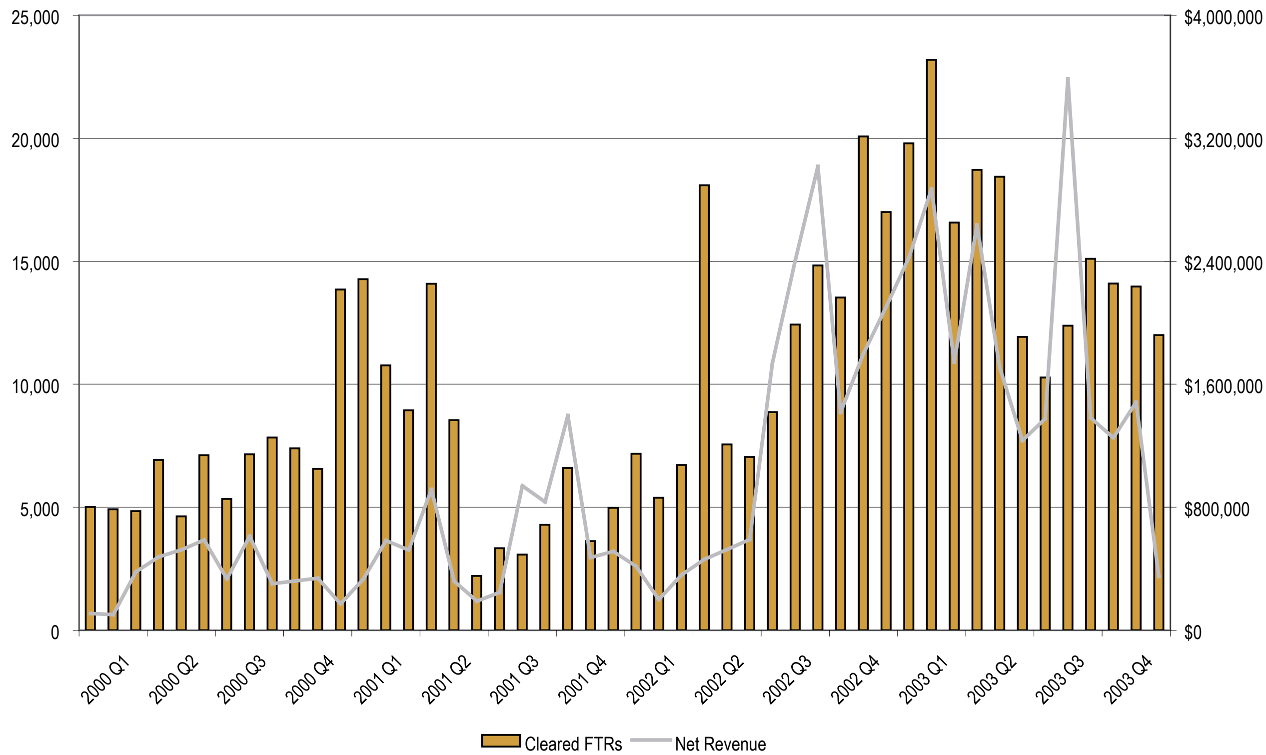
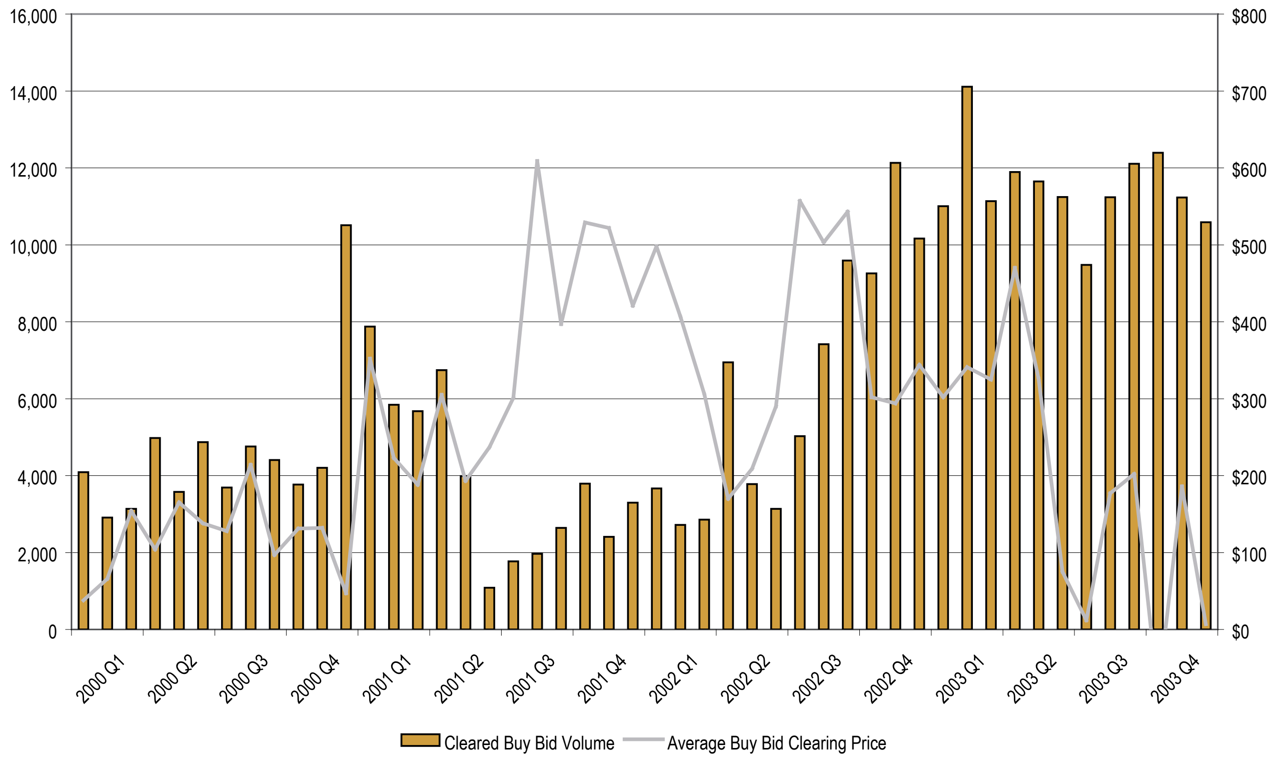


Figure 7-5 depicts the total cleared bid and offer volume together with the total auction revenue generated each month. Average monthly auction revenue grew from $350,000 per month in 2000 to over $600,000 per month in 2001, $1.2 million per month in 2002 and $1.8 million per month in 2003. The $21.6 million 2003 total revenue represented a $10 million increase from 2002. As of December 31, 2003, $52 million of net revenue had been produced by the Monthly FTR Auction and distributed to transmission owners and customers.

Figure 7-6 Cleared Monthly FTR Auction Buy Bids and Average Buy Bid Price: 2003



Total bid and offer volume increased from an historical average of 5,300 MW-months during 1999 through 2001 to 11,500 and 15,500 MW-months in 2002 and 2003, respectively. Also shown is that after PJM implemented the Annual FTR Auction, the monthly auction revenue and volume both dropped off considerably, another indication that the Annual FTR Auction has made more long-term FTRs available. The new design has allowed market participants to obtain long-term FTRs directly in the annual auction, which has reduced reliance on monthly FTR auctions.

Figure 7-6 presents Monthly FTR Auction cleared bid volume and average buy bid clearing price. As shown, average cleared bid price dropped from the historical average of $350 in 2001 and 2002 to $195 in 2003, with the entire drop occurring after the advent of the Annual FTR Auction. The volume remained high during the postauction period, and, as shown in the previous figure, net auction revenue also remained higher in 2003 than during previous years. Bid and offer volume comparison continues to show that bid volume far exceeds offer volume by a nearly 10:1 ratio.

Figure 7-7 Highest Revenue Producing Monthly FTR Auction Sinks Purchased

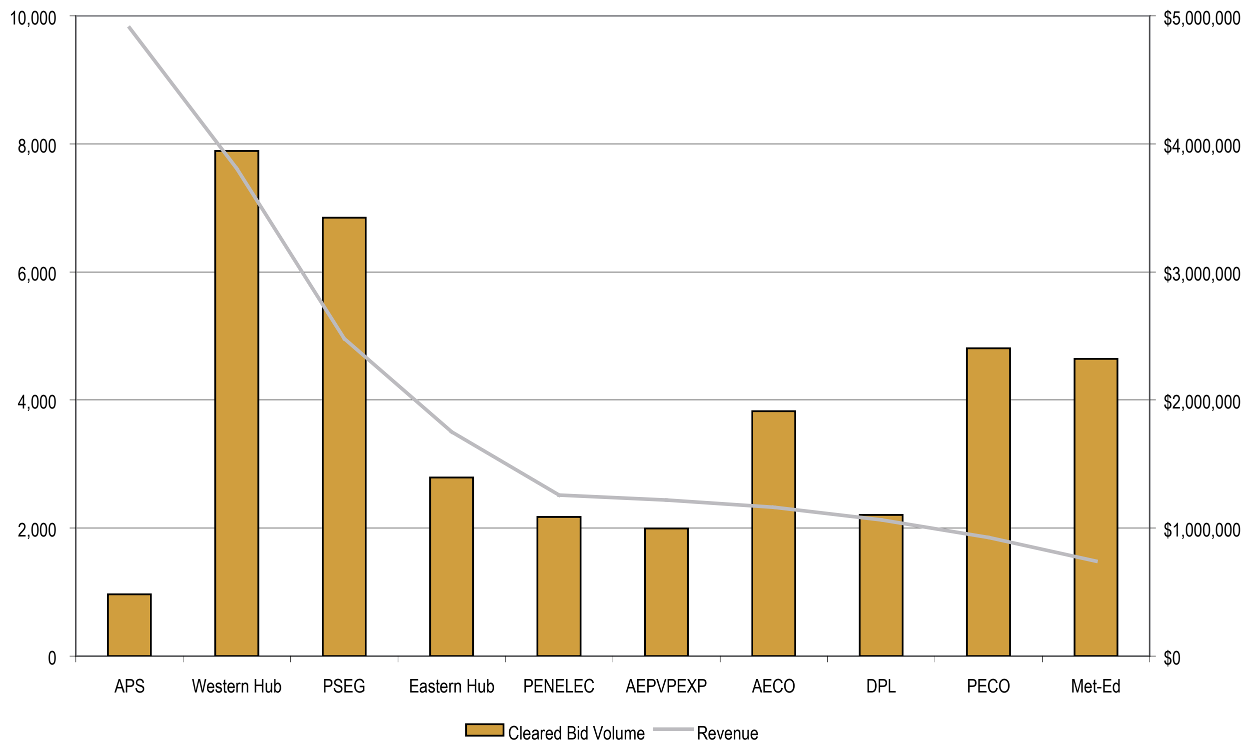
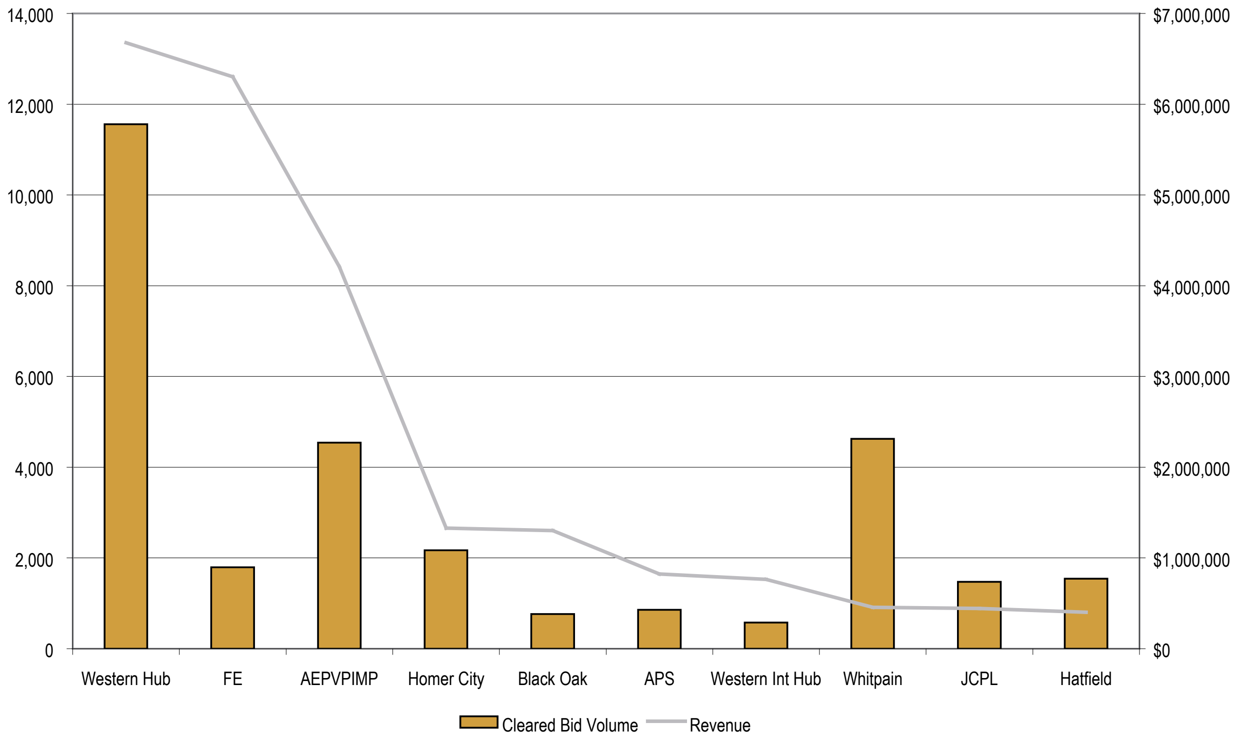


Figure 7-7 shows the 10 FTRs that generated the greatest amount of monthly auction revenue grouped by the FTR destination (sink). FTRs to these sinks accounted for $19.3 million, just under 40 percent, of all revenue paid and comprised 12 percent of all FTRs bought in Monthly FTR Auctions. These sinks tended to be at the western-most and eastern-most parts of the PJM system.

Figure 7-8 shows the 10 FTRs that generated the greatest amount of monthly auction revenue, grouped by the FTR origin (source). FTRs from these sources accounted for $22.7 million, just under 40 percent, of all revenue paid and comprised 12 percent of all FTRs purchased in Monthly FTR Auctions. These sources are concentrated in the western part of the PJM system.

Figure 7-8 Highest Revenue Producing Monthly FTR Auction Sources Purchased



Daily FTR Market Activity

Outside of the annual and monthly FTR auction processes, FTRs may be traded between market participants through bilateral transactions. Bilateral activity declined to 1,352 MW, or 2 percent of all FTRs in 2003 from 7,173 MW in 2002, or 21 percent of all FTRs in 2002.

FTR Revenue Adequacy

FTR target allocations are based on hourly, day-ahead FTR path prices and represent revenue required to hedge FTR holders fully against congestion. FTR credits represent revenue actually paid to FTR holders, and, depending on market conditions, can be less than the target allocations needed to fully hedge congestion incurred during some periods. During the 2003 calendar year, target allocations totaled $521 million and congestion credits totaled $499 million, fulfilling FTR target allocations at the 96 percent level, a level consistent with historical payouts. For full congestion accounting and FTR revenue adequacy data, please refer to Table 6-2 in the Congestion section of this report.

FTR Target Allocations

Table 7-6 Ten Greatest Net, Positive and Negative FTR Target Allocations Summed by Sink and Source

Ten Greatest Net FTR Target Allocations Summed by Sink and Source

Sink	Target Allocations	%Total	Source	Target Allocations	%Total
APS Zone	$88,932,116	22%	Keystone/Conemaugh	$42,314,224	10%
PSEG Zone	$61,626,730	15%	AEP/VP Imports	$41,994,676	10%
PECO Zone	$58,331,194	14%	Western Hub	$32,776,081	8%
PEPCO Zone	$42,432,176	10%	First Energy	$27,138,623	7%
Western Hub	$24,645,017	6%	Pleasants Generators	$21,859,195	5%
PPL Zone	$22,314,865	5%	Peach Bottom Generators	$13,463,131	3%
BGE Zone	$15,870,417	4%	Homer City Generators	$9,236,795	2%
AECO Zone	$14,017,776	3%	TMI Generator	$8,528,145	2%
Met-Ed Zone	$12,530,250	3%	Limerick Generators	$7,984,787	2%
Eastern Hub	$10,933,168	3%	Fort Martin Generators	$5,306,623	1%
Totals	**$351,633,708**	**85%**	**Totals**	**$210,602,280**	**51%**

Ten Greatest Positive FTR Target Allocations Summed by Sink and Source

Sink	Target Allocations	%Total	Source	Target Allocations	%Total
APS Zone	$93,406,781	19%	Keystone/Conemaugh	$42,354,397	9%
PECO Zone	$64,077,266	13%	AEP/VP Imports	$42,119,352	9%
PSEG Zone	$62,797,633	13%	Western Hub	$35,378,963	7%
PEPCO Zone	$42,852,561	9%	First Energy	$27,141,584	6%
Western Hub	$27,215,587	6%	Peach Bottom Generators	$13,506,349	3%
PPL Zone	$26,439,756	5%	Pleasants Generators	$13,108,080	3%
BGE Zone	$18,383,546	4%	Limerick Generators	$8,958,622	2%
PENELEC Zone	$17,262,301	4%	TMI Generator	$8,919,777	2%
AECO Zone	$14,785,803	3%	PECO Zone	$5,457,599	1%
Met-Ed Zone	$14,544,835	3%	Fort Martin Generators	$5,306,623	1%
Totals	**$381,766,068**	**78%**	**Totals**	**$202,251,349**	**41%**

Ten Greatest Negative FTR Target Allocations Summed by Sink and Source

Sink	Target Allocations	%Total	Source	Target Allocations	%Total
PENELEC Zone	($9,328,042)	12%	Salem Generators	($4,221,721)	5%
Western Interface Hub	($7,467,701)	10%	Limerick Generators	($4,176,501)	5%
PECO Zone	($5,746,072)	7%	Eastern Hub	($3,788,439)	5%
JCPL Zone	($5,163,883)	7%	Calvert Cliffs Generators	($2,666,023)	3%
APS Zone	($4,474,665)	6%	New Jersey Hub	($2,637,822)	3%
PPL Zone	($4,124,891)	5%	Western Hub	($2,602,883)	3%
First Energy	($3,171,850)	4%	Marlowe	($2,536,063)	3%
Western Hub	($2,570,571)	3%	Peco Zone	($2,442,644)	3%
BGE Zone	($2,513,129)	3%	Edgemoor Generators	($1,682,639)	2%
Met-Ed Zone	($2,014,585)	3%	England Generators	($1,672,100)	2%
Totals	**($46,575,390)**	**60%**	**Totals**	**($28,426,834)**	**37%**

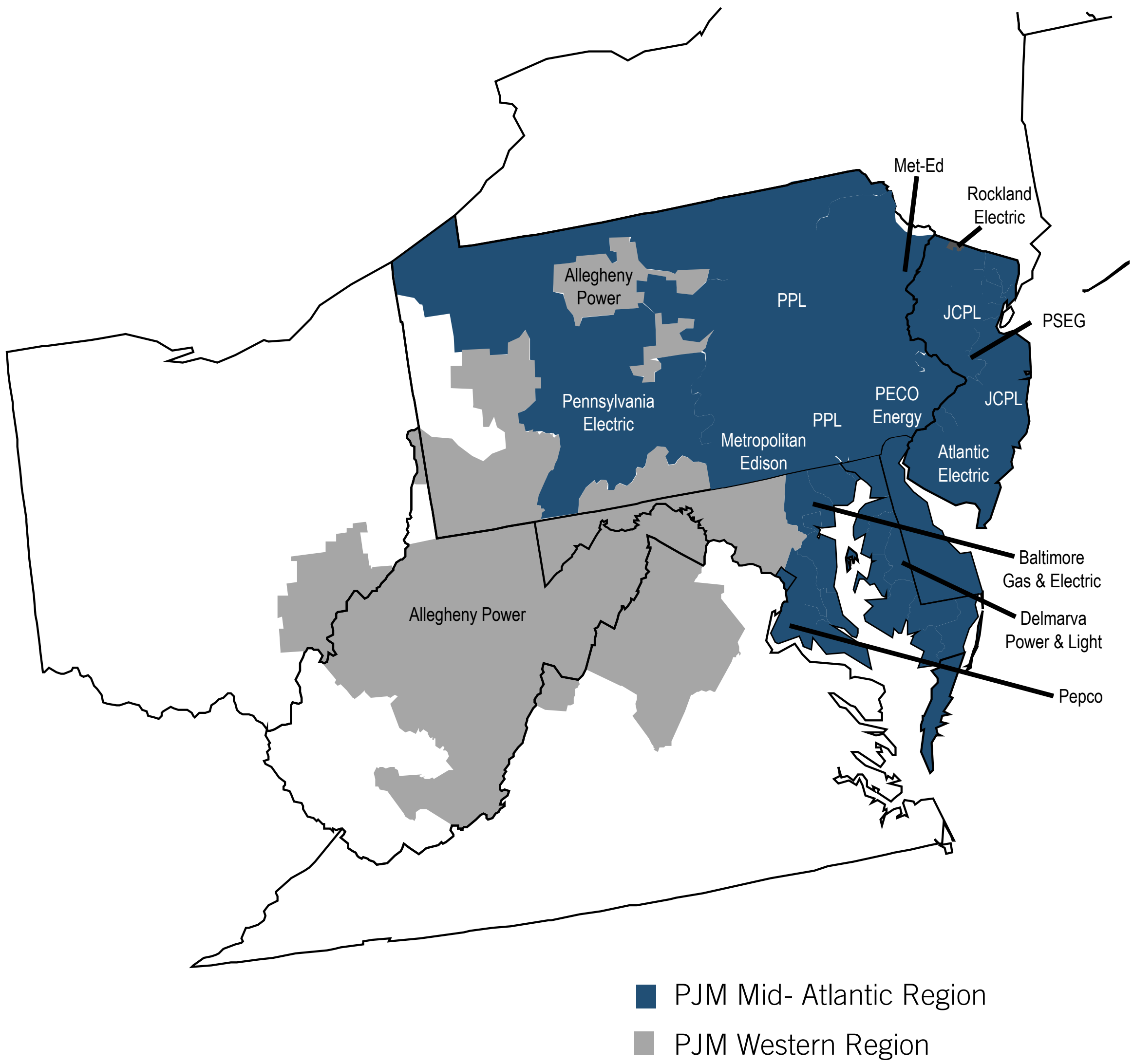
Table 7-6 itemizes the highest value net positively valued and negatively valued FTR target allocations for 2003 by sources and sinks.

- **Largest Net Financial Benefits.** The top section of Table 7-6 shows the 10 FTR sinks and sources with the largest targeted, net financial benefits for the period. The top-10 sinks are spread throughout PJM and accounted for more than $352 million (85 percent) of the net $413 million net target allocations. FTRs with the APS zone as the sink had 22 percent (over $88 million) of all target allocations. The table also shows target allocations for FTR sources. These top-10 sources accounted for more than $211 million (51 percent) of net target allocations. Seven of the top-10 sources are located in or near the PJM Western Region. FTRs with the Keystone/Conemaugh generators as the source had over $42 million (10 percent) of all target allocations.

- **Largest Positive Financial Benefits.** The middle section of Table 7-6 shows the 10 FTR sinks and sources with the largest targeted, positive financial benefits for the period. The top-10 sinks are spread throughout PJM and accounted for more than $382 million (78 percent) of the $490 million positive target allocations. FTRs with APS zone as the sink had 19 percent ($93 million) of all positive target allocations. The table also shows the same data for FTR sources. These top-10 sources accounted for $202 million (41 percent) of positive target allocations. Six of these top-10 sources are located in or near the PJM Western Region. FTRs with the Keystone/Conemaugh generators and American Electric Power Company, Inc./Virginia Electric and Power Company (AEP/VAP) interface as sources each had over $42 million (9 percent) of all positive target allocations.

- **Largest Financial Liabilities.** The bottom section of Table 7-6 shows the 10 FTR sinks and sources with the largest targeted financial liabilities for the period. The top-10 sinks are spread throughout PJM and accounted for over $47 million (60 percent) of the $77 million negative target allocations. FTRs with PENELEC zone as the sink had 12 percent ($9 million) of all negative target allocations. The table also shows negative target allocations for FTR sources. The top-10 sources accounted for $28 million (37 percent) of negative target allocations. Most of these sources are located in the eastern part of the PJM system. FTRs with Salem and Limerick as the source each had over $4 million (5 percent) of all negative target allocations.

Appendix A – PJM Service Area



JCPL	Jersey Central Power & Light Company
Met-Ed	Metropolitan Edison Company
PECO Energy	PECO Energy Company
Pepco	Pepco (formerly Potomac Electric Power Company)
PPL	PPL Electric Utilities Corporation
PSEG	Public Service Electric and Gas Company

Appendix B – PJM Market Milestones

Year	Month	Event
1996	April	FERC Order 888
1997	April	Bid-based Energy Market
	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
	April	Competitive 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 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

Appendix C – Energy Market

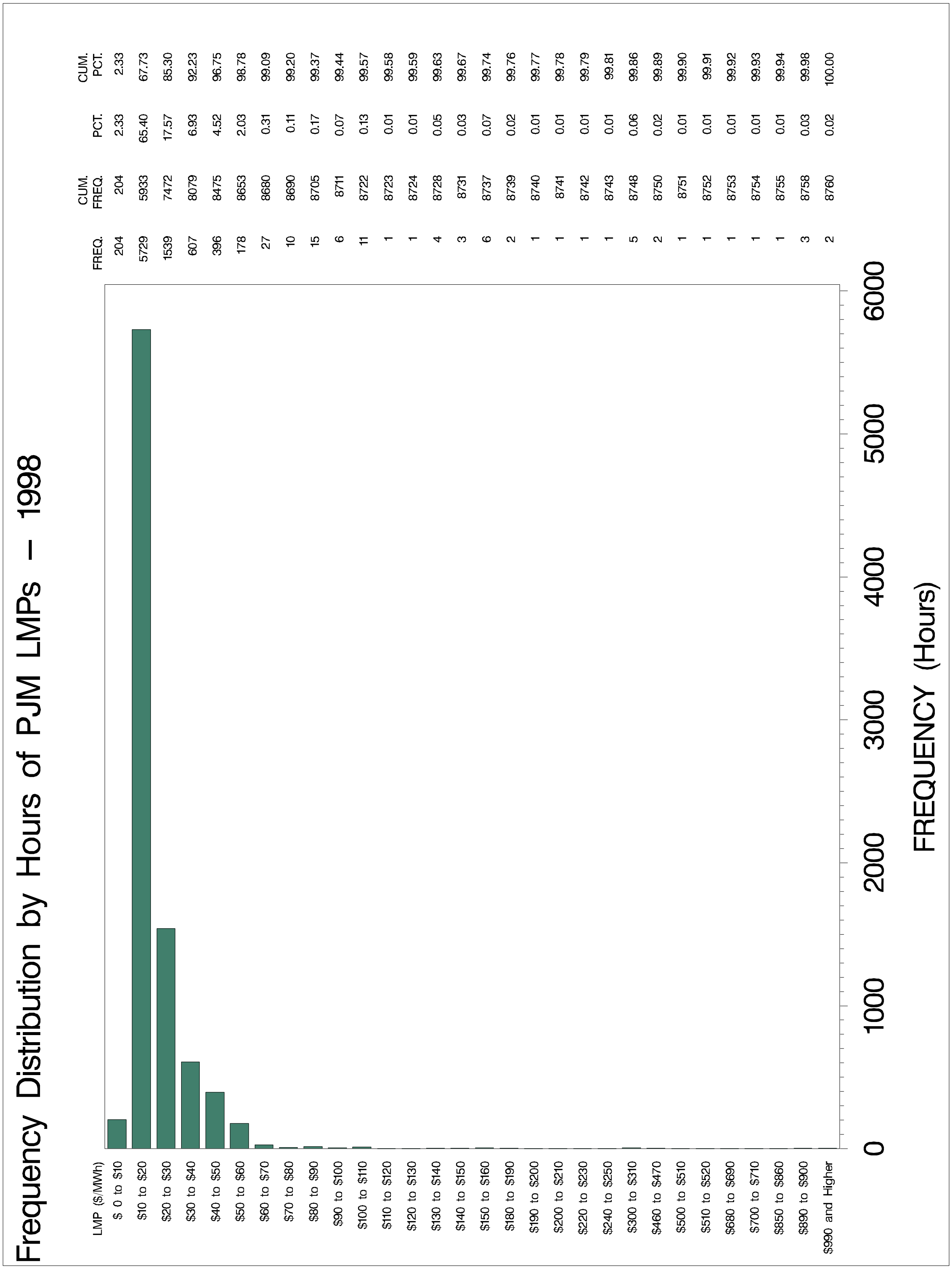
Frequency Distribution of LMP

Figure C-1, Figure C-2, Figure C-3, Figure C-4, Figure C-5 and Figure C-6 provide frequency distribution of real-time locational marginal price (LMP), by hour, for 1998, 1999, 2000, 2001, 2002 and 2003.[1] The figures show the number of hours (FREQ.), the cumulative number of hours (CUM FREQ.), the percent of hours (PCT.) and the cumulative percent of hours (CUM PCT.) that LMP was within a given, $10-price interval, or for the cumulative columns, within the interval plus all the lower price intervals.[2]

1 LMP was instituted in PJM in April 1998. Before then, there had been a single system price, the market-clearing price (MCP).

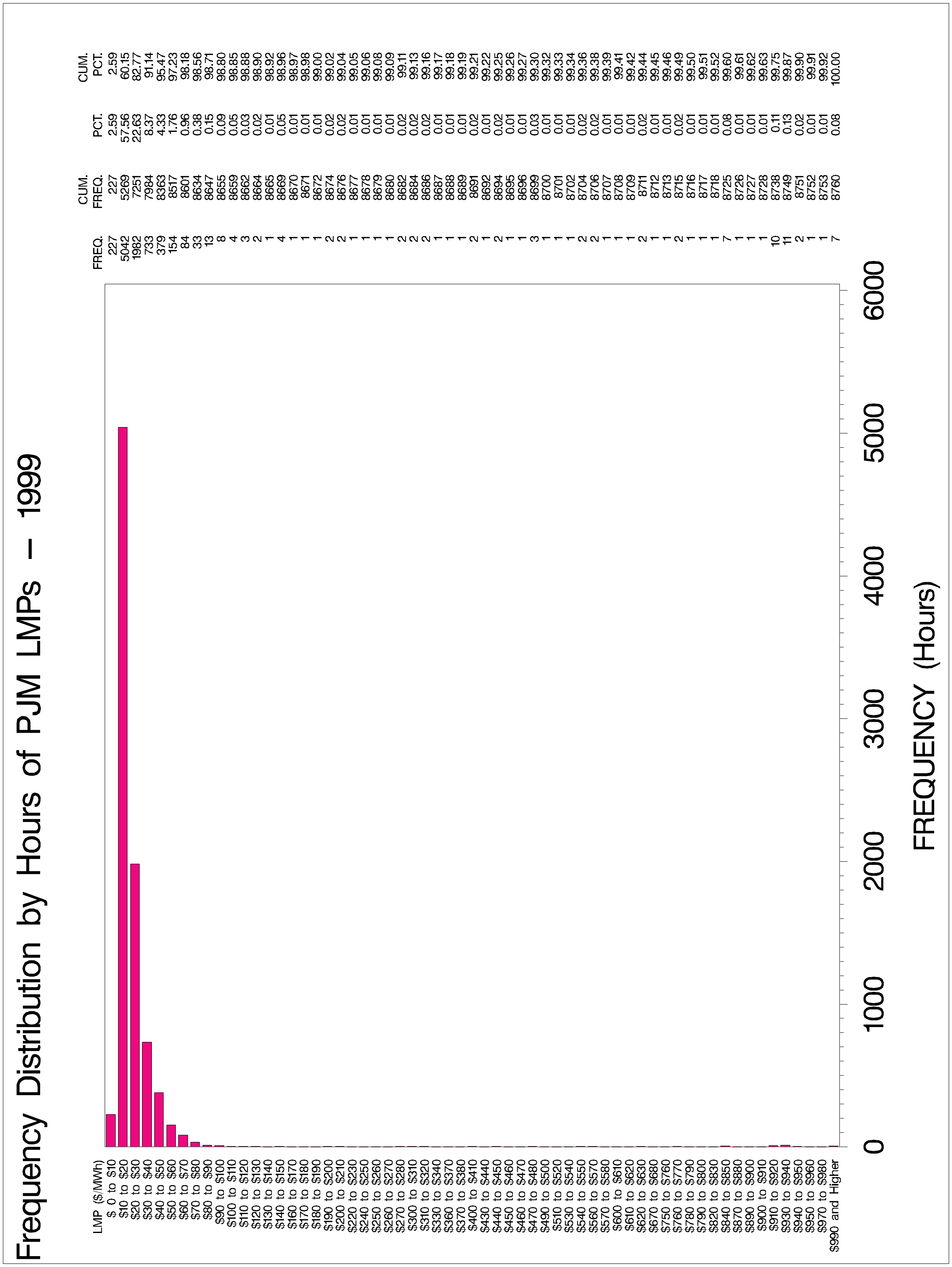
2 Only LMP intervals with a positive frequency are included in the figures.

Figure C-1 Frequency Distribution by Hours of PJM LMP: 1998



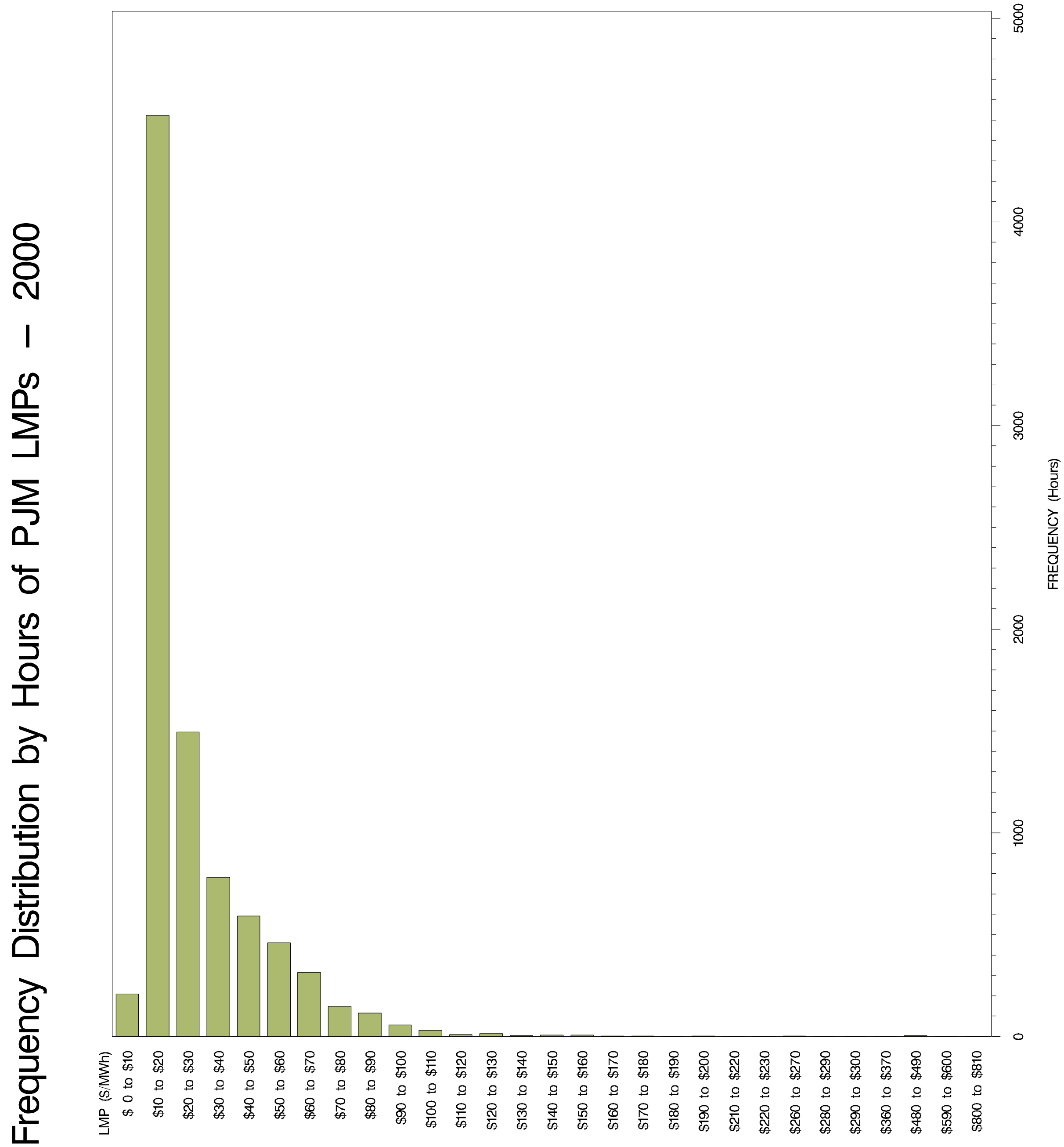
LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	204	204	2.33	2.33
$10 to $20	5729	5933	65.40	67.73
$20 to $30	1539	7472	17.57	85.30
$30 to $40	607	8079	6.93	92.23
$40 to $50	396	8475	4.52	96.75
$50 to $60	178	8653	2.03	98.78
$60 to $70	27	8680	0.31	99.09
$70 to $80	10	8690	0.11	99.20
$80 to $90	15	8705	0.17	99.37
$90 to $100	6	8711	0.07	99.44
$100 to $110	11	8722	0.13	99.57
$110 to $120	1	8723	0.01	99.58
$120 to $130	1	8724	0.01	99.59
$130 to $140	4	8728	0.05	99.63
$140 to $150	3	8731	0.03	99.67
$150 to $160	6	8737	0.07	99.74
$180 to $190	2	8739	0.02	99.76
$190 to $200	1	8740	0.01	99.77
$200 to $210	1	8741	0.01	99.78
$220 to $230	1	8742	0.01	99.79
$240 to $250	1	8743	0.01	99.81
$300 to $310	5	8748	0.06	99.86
$460 to $470	2	8750	0.02	99.89
$500 to $510	1	8751	0.01	99.90
$510 to $520	1	8752	0.01	99.91
$680 to $690	1	8753	0.01	99.92
$700 to $710	1	8754	0.01	99.93
$850 to $860	1	8755	0.01	99.94
$890 to $900	3	8758	0.03	99.98
$990 and Higher	2	8760	0.02	100.00

Figure C-2 Frequency Distribution by Hours of PJM LMP: 1999



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	227	227	2.59	2.59
$10 to $20	5042	5269	57.56	60.15
$20 to $30	1982	7251	22.63	82.77
$30 to $40	733	7984	8.37	91.14
$40 to $50	379	8363	4.33	95.47
$50 to $60	154	8517	1.76	97.23
$60 to $70	84	8601	0.96	98.18
$70 to $80	33	8634	0.38	98.56
$80 to $90	13	8647	0.15	98.71
$90 to $100	8	8655	0.09	98.80
$100 to $110	4	8659	0.05	98.85
$110 to $120	3	8662	0.03	98.88
$120 to $130	2	8664	0.02	98.90
$130 to $140	1	8665	0.01	98.92
$140 to $150	4	8669	0.05	98.96
$160 to $170	1	8670	0.01	98.97
$170 to $180	1	8671	0.01	98.98
$180 to $190	1	8672	0.01	99.00
$190 to $200	2	8674	0.02	99.02
$200 to $210	2	8676	0.02	99.04
$220 to $230	1	8677	0.01	99.05
$240 to $250	1	8678	0.01	99.06
$250 to $260	1	8679	0.01	99.08
$260 to $270	1	8680	0.01	99.09
$270 to $280	2	8682	0.02	99.11
$300 to $310	2	8684	0.02	99.13
$310 to $320	2	8686	0.02	99.16
$330 to $340	1	8687	0.01	99.17
$360 to $370	1	8688	0.01	99.18
$370 to $380	1	8689	0.01	99.19
$400 to $410	2	8691	0.02	99.21
$430 to $440	1	8692	0.01	99.22
$440 to $450	2	8694	0.02	99.25
$450 to $460	1	8695	0.01	99.26
$460 to $470	1	8696	0.01	99.27
$470 to $480	3	8699	0.03	99.30
$490 to $500	1	8700	0.01	99.32
$510 to $520	1	8701	0.01	99.33
$530 to $540	1	8702	0.01	99.34
$540 to $550	2	8704	0.02	99.36
$560 to $570	2	8706	0.02	99.38
$570 to $580	1	8707	0.01	99.39
$600 to $610	1	8708	0.01	99.41
$610 to $620	1	8709	0.01	99.42
$620 to $630	2	8711	0.02	99.44
$670 to $680	1	8712	0.01	99.45
$750 to $760	1	8713	0.01	99.46
$760 to $770	2	8715	0.02	99.49
$780 to $790	1	8716	0.01	99.50
$790 to $800	1	8717	0.01	99.51
$820 to $830	1	8718	0.01	99.52
$840 to $850	7	8725	0.08	99.60
$870 to $880	1	8726	0.01	99.61
$890 to $900	1	8727	0.01	99.62
$900 to $910	1	8728	0.01	99.63
$910 to $920	10	8738	0.11	99.75
$930 to $940	11	8749	0.13	99.87
$940 to $950	2	8751	0.02	99.90
$950 to $960	1	8752	0.01	99.91
$970 to $980	1	8753	0.01	99.92
$990 and Higher	7	8760	0.08	100.00

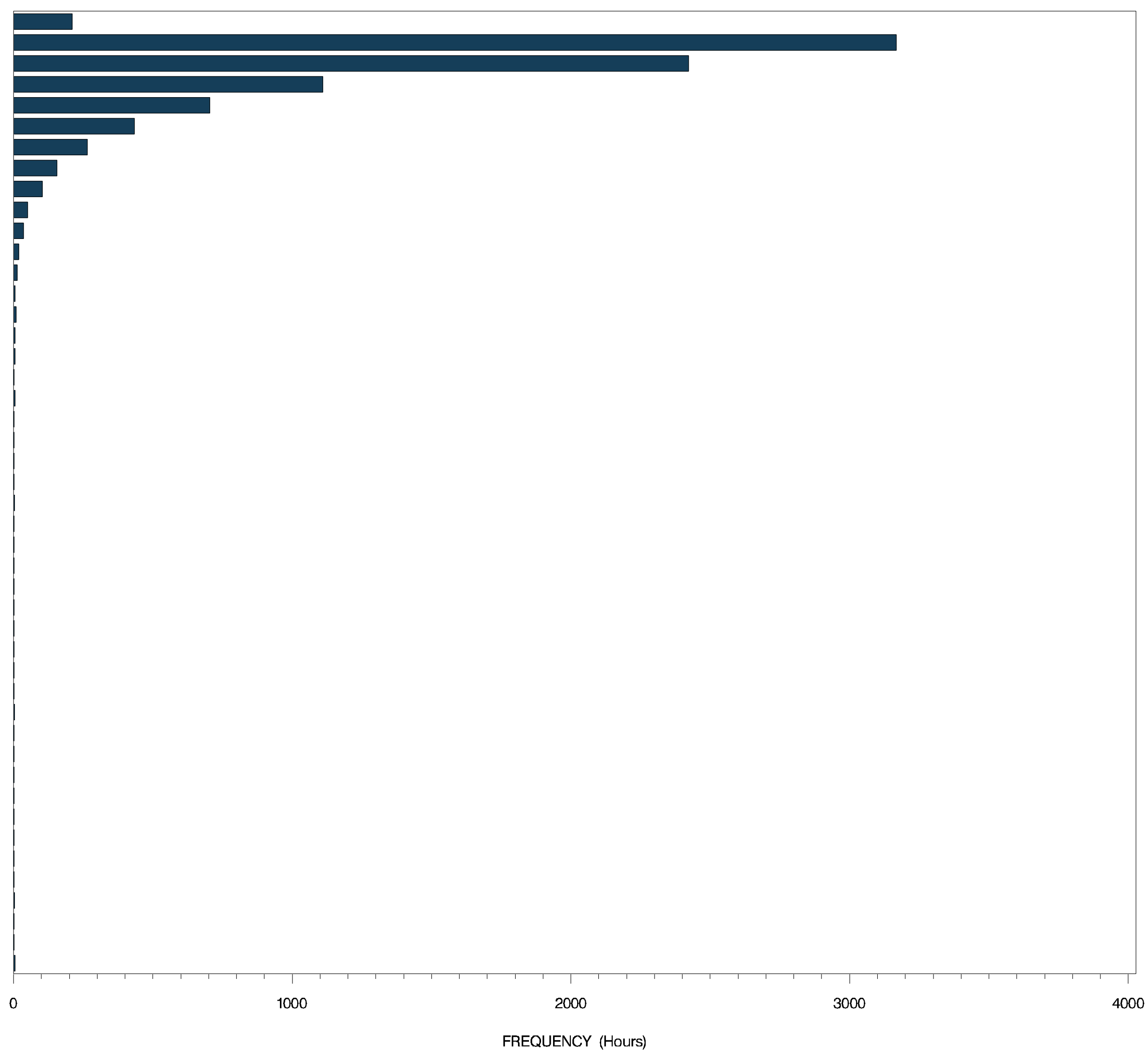
Figure C-3 Frequency Distribution by Hours of PJM LMP: 2000



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	210	210	2.39	2.39
$10 to $20	4522	4732	51.48	53.87
$20 to $30	1494	6226	17.01	70.88
$30 to $40	782	7008	8.90	79.78
$40 to $50	591	7599	6.73	86.51
$50 to $60	459	8058	5.23	91.73
$60 to $70	315	8373	3.59	95.32
$70 to $80	147	8520	1.67	96.99
$80 to $90	115	8635	1.31	98.30
$90 to $100	56	8691	0.64	98.94
$100 to $110	31	8722	0.35	99.29
$110 to $120	9	8731	0.10	99.40
$120 to $130	13	8744	0.15	99.54
$130 to $140	5	8749	0.06	99.60
$140 to $150	8	8757	0.09	99.69
$150 to $160	6	8763	0.07	99.76
$160 to $170	3	8766	0.03	99.80
$170 to $180	2	8768	0.02	99.82
$180 to $190	1	8769	0.01	99.83
$190 to $200	2	8771	0.02	99.85
$210 to $220	1	8772	0.01	99.86
$220 to $230	1	8773	0.01	99.87
$260 to $270	2	8775	0.02	99.90
$280 to $290	1	8776	0.01	99.91
$290 to $300	1	8777	0.01	99.92
$360 to $370	1	8778	0.01	99.93
$480 to $490	4	8782	0.05	99.98
$590 to $600	1	8783	0.01	99.99
$800 to $810	1	8784	0.01	100.00

Figure C-4 Frequency Distribution by Hours of PJM LMP: 2001

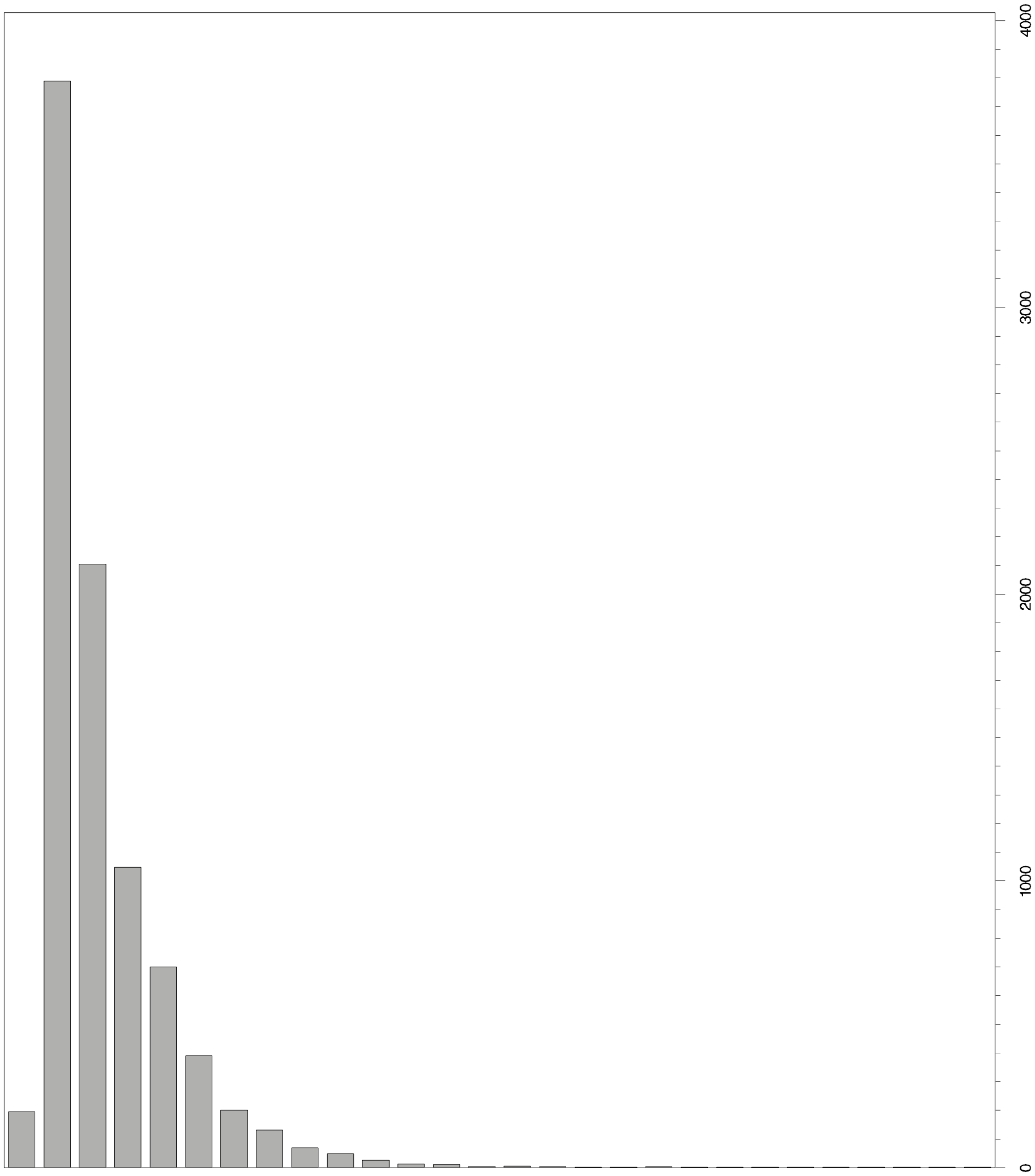
Frequency Distribution by Hours of PJM LMPs – 2001



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	210	210	2.40	2.40
$10 to $20	3167	3377	36.15	38.55
$20 to $30	2423	5800	27.66	66.21
$30 to $40	1109	6909	12.66	78.87
$40 to $50	704	7613	8.04	86.91
$50 to $60	433	8046	4.94	91.85
$60 to $70	264	8310	3.01	94.86
$70 to $80	155	8465	1.77	96.63
$80 to $90	104	8569	1.19	97.82
$90 to $100	50	8619	0.57	98.39
$100 to $110	36	8655	0.41	98.80
$110 to $120	18	8673	0.21	99.01
$120 to $130	13	8686	0.15	99.16
$130 to $140	5	8691	0.06	99.21
$140 to $150	9	8700	0.10	99.32
$150 to $160	6	8706	0.07	99.38
$160 to $170	6	8712	0.07	99.45
$170 to $180	2	8714	0.02	99.47
$180 to $190	5	8719	0.06	99.53
$190 to $200	1	8720	0.01	99.54
$210 to $220	1	8721	0.01	99.55
$240 to $250	1	8722	0.01	99.57
$250 to $260	1	8723	0.01	99.58
$260 to $270	3	8726	0.03	99.61
$280 to $290	1	8727	0.01	99.62
$290 to $300	1	8728	0.01	99.63
$320 to $330	1	8729	0.01	99.65
$330 to $340	2	8731	0.02	99.67
$360 to $370	1	8732	0.01	99.68
$370 to $380	2	8734	0.02	99.70
$390 to $400	1	8735	0.01	99.71
$440 to $450	1	8736	0.01	99.73
$470 to $480	1	8737	0.01	99.74
$520 to $530	3	8740	0.03	99.77
$530 to $540	1	8741	0.01	99.78
$550 to $560	2	8743	0.02	99.81
$620 to $630	1	8744	0.01	99.82
$650 to $660	2	8746	0.02	99.84
$690 to $700	1	8747	0.01	99.85
$740 to $750	1	8748	0.01	99.86
$770 to $780	1	8749	0.01	99.87
$830 to $840	1	8750	0.01	99.89
$900 to $910	3	8753	0.03	99.92
$910 to $920	1	8754	0.01	99.93
$920 to $930	1	8755	0.01	99.94
$930 to $940	5	8760	0.06	100.00

Figure C-5 Frequency Distribution by Hours of PJM LMP: 2002

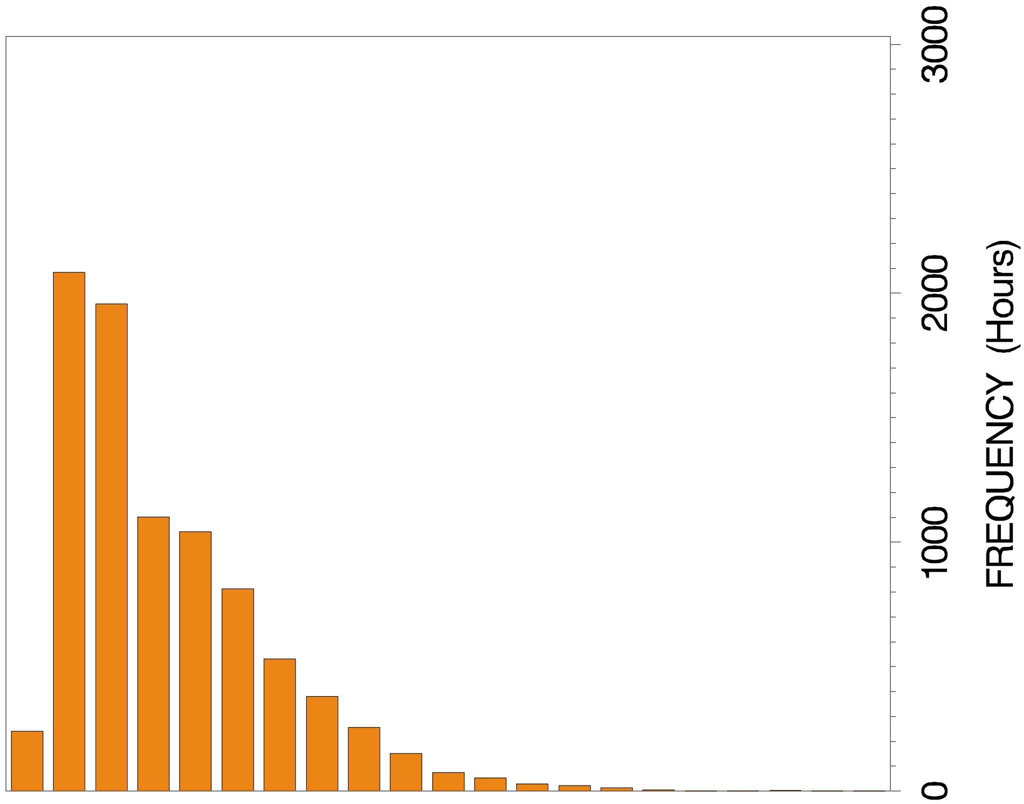
Frequency Distribution by Hours of PJM LMPs – 2002



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	195	195	2.23	2.23
$10 to $20	3790	3985	43.26	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: 2003

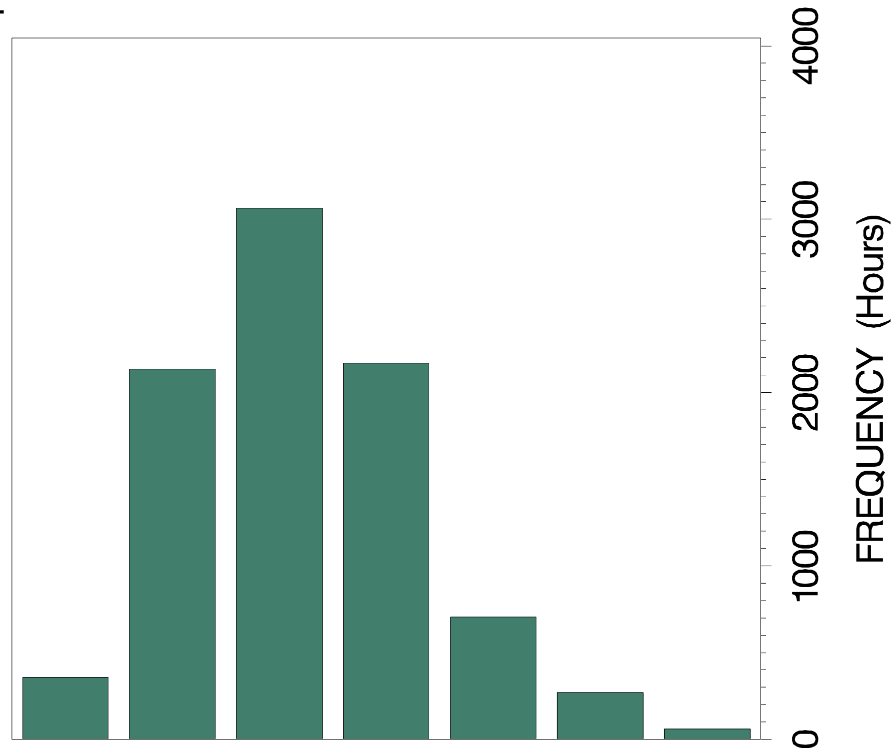
Frequency Distribution by Hours of PJM LMPs – 2003



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	241	241	2.75	2.75
$10 to $20	2083	2324	23.78	26.53
$20 to $30	1957	4281	22.34	48.87
$30 to $40	1102	5383	12.58	61.45
$40 to $50	1043	6426	11.91	73.36
$50 to $60	812	7238	9.27	82.63
$60 to $70	532	7770	6.07	88.70
$70 to $80	380	8150	4.34	93.04
$80 to $90	255	8405	2.91	95.95
$90 to $100	152	8557	1.74	97.68
$100 to $110	75	8632	0.86	98.54
$110 to $120	52	8684	0.59	99.13
$120 to $130	28	8712	0.32	99.45
$130 to $140	23	8735	0.26	99.71
$140 to $150	14	8749	0.16	99.87
$150 to $160	5	8754	0.06	99.93
$160 to $170	1	8755	0.01	99.94
$170 to $180	1	8756	0.01	99.95
$180 to $190	2	8758	0.02	99.98
$190 to $200	1	8759	0.01	99.99
$210 to $220	1	8760	0.01	100.00

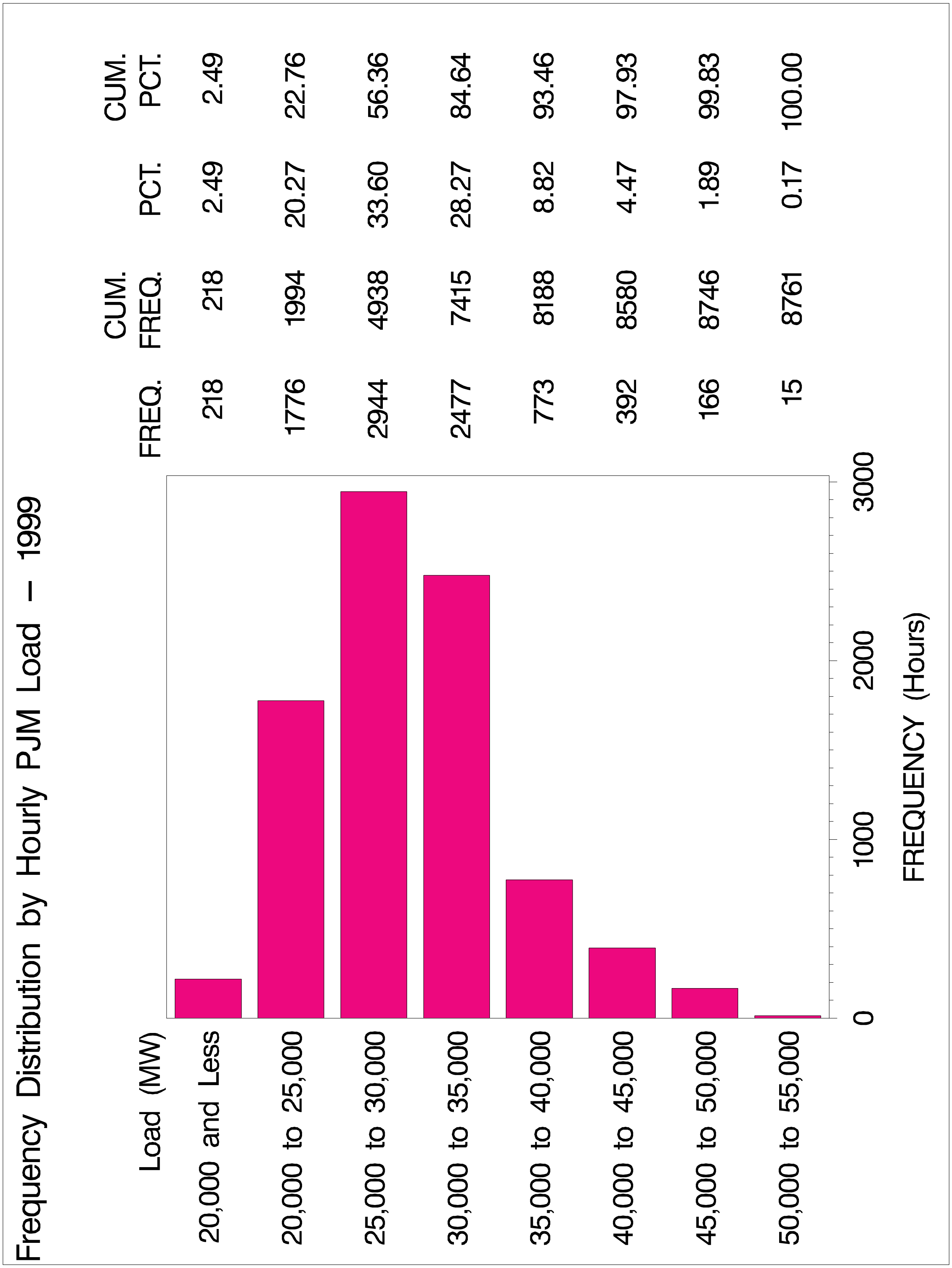
Figure C-7 Frequency Distribution of Hourly PJM Load: 1998

Frequency Distribution by Hourly PJM Load – 1998



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	356	356	4.06	4.06
20,000 to 25,000	2137	2493	24.39	28.46
25,000 to 30,000	3063	5556	34.97	63.42
30,000 to 35,000	2171	7727	24.78	88.21
35,000 to 40,000	704	8431	8.04	96.24
40,000 to 45,000	270	8701	3.08	99.33
45,000 to 50,000	59	8760	0.67	100.00

Figure C-8 Frequency Distribution of Hourly PJM Load: 1999



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	218	218	2.49	2.49
20,000 to 25,000	1776	1994	20.27	22.76
25,000 to 30,000	2944	4938	33.60	56.36
30,000 to 35,000	2477	7415	28.27	84.64
35,000 to 40,000	773	8188	8.82	93.46
40,000 to 45,000	392	8580	4.47	97.93
45,000 to 50,000	166	8746	1.89	99.83
50,000 to 55,000	15	8761	0.17	100.00

Figure C-9 Frequency Distribution of Hourly PJM Load: 2000

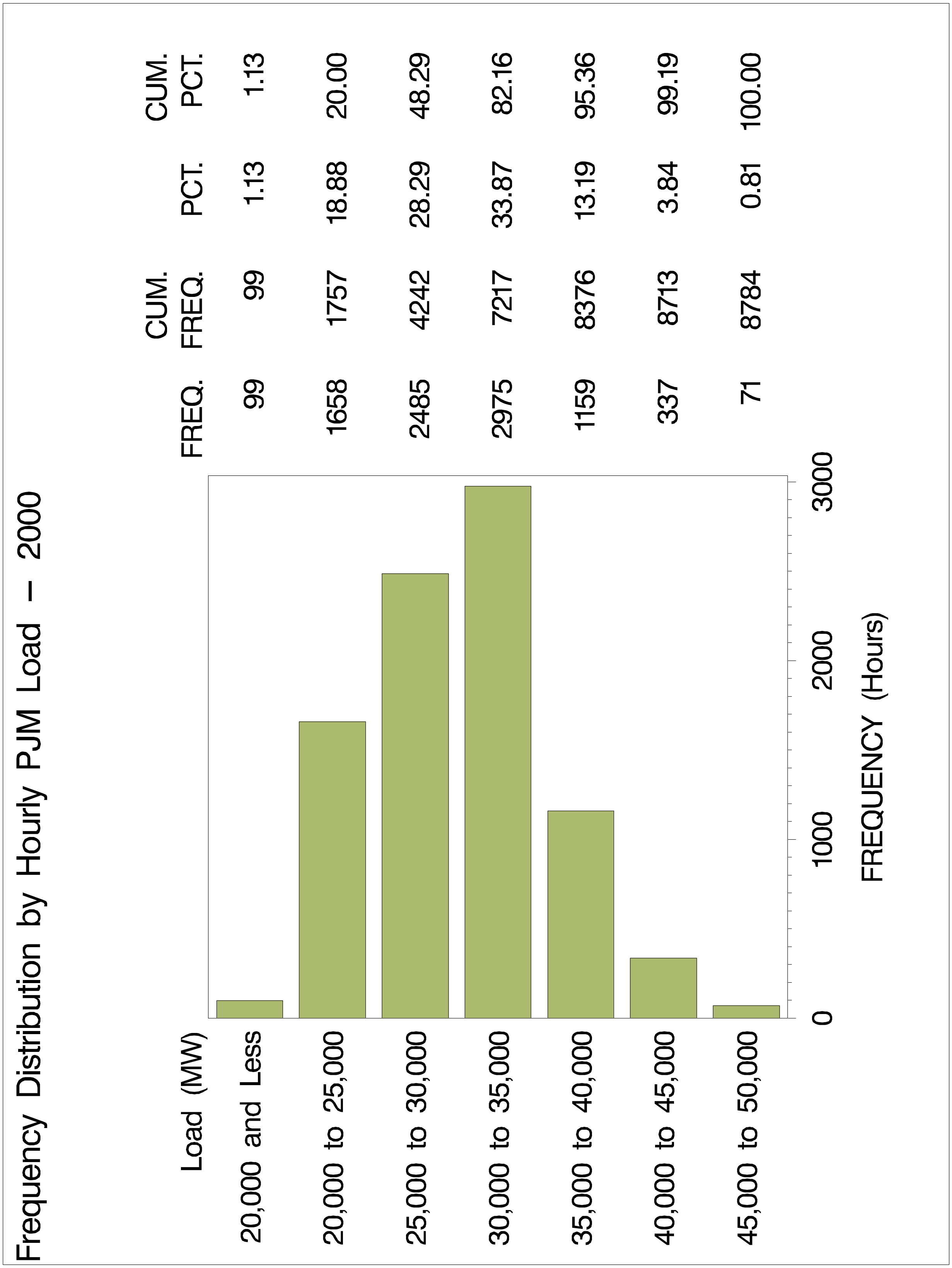


Figure C-10 Frequency Distribution of Hourly PJM Load: 2001

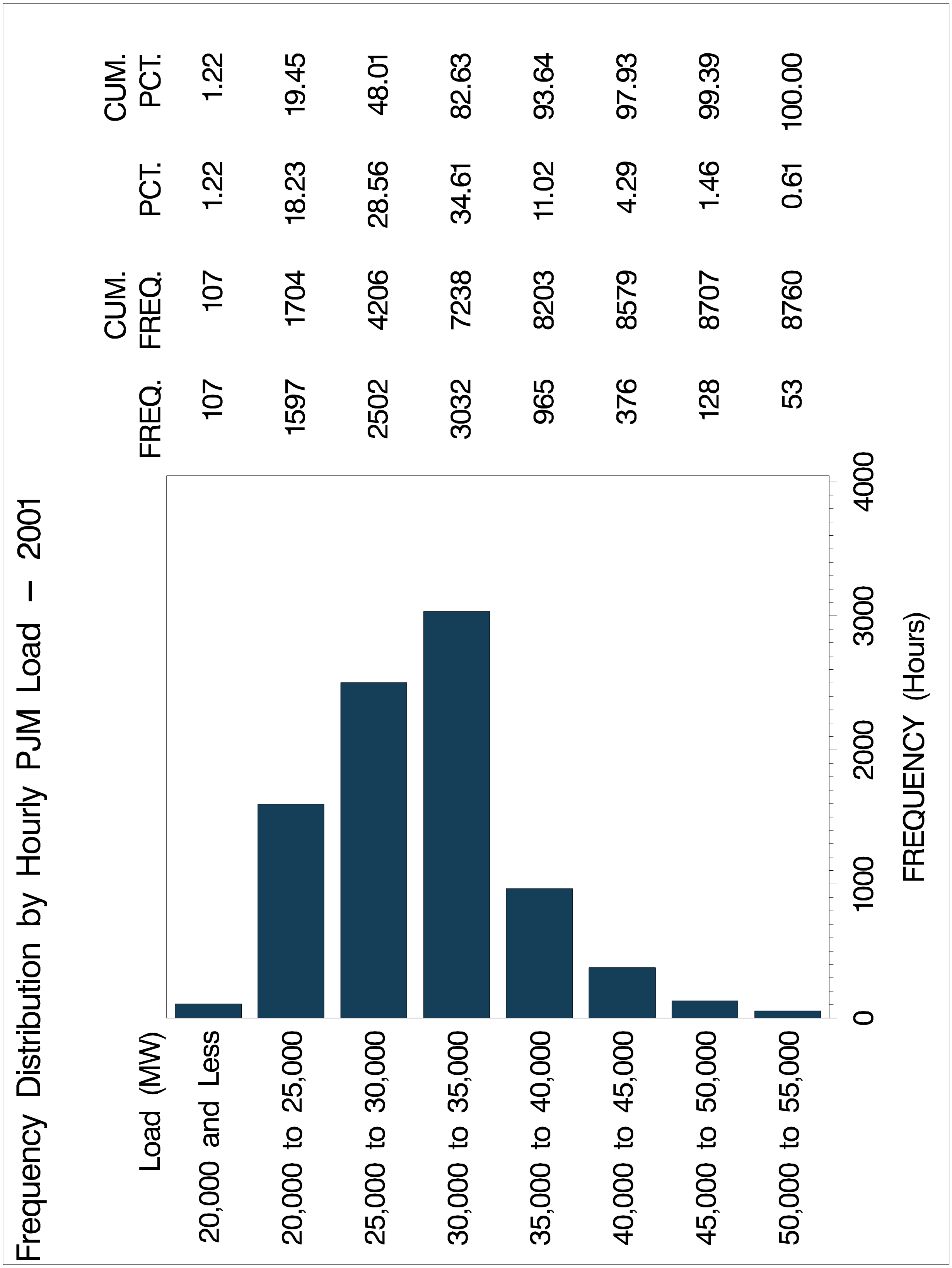
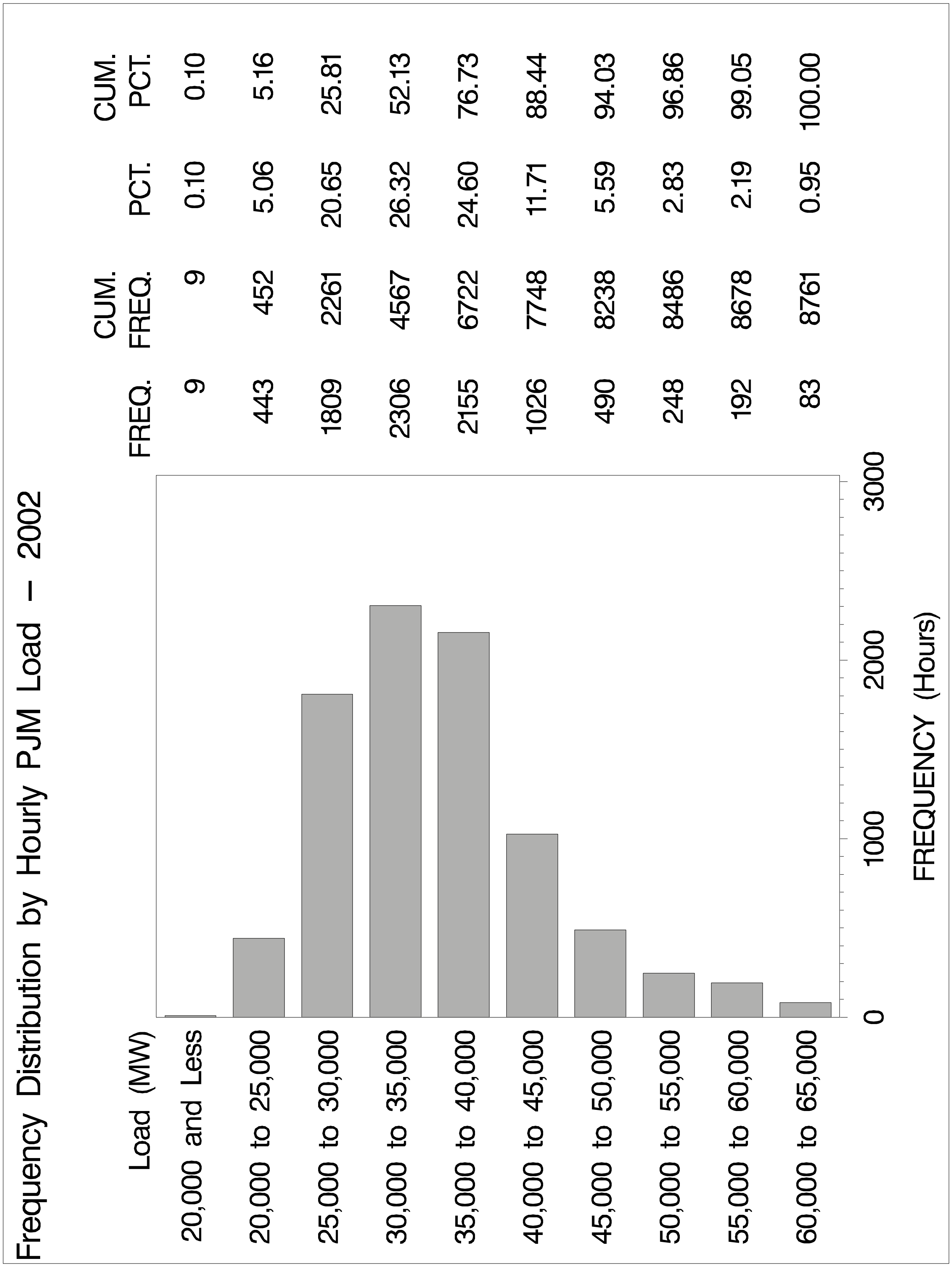
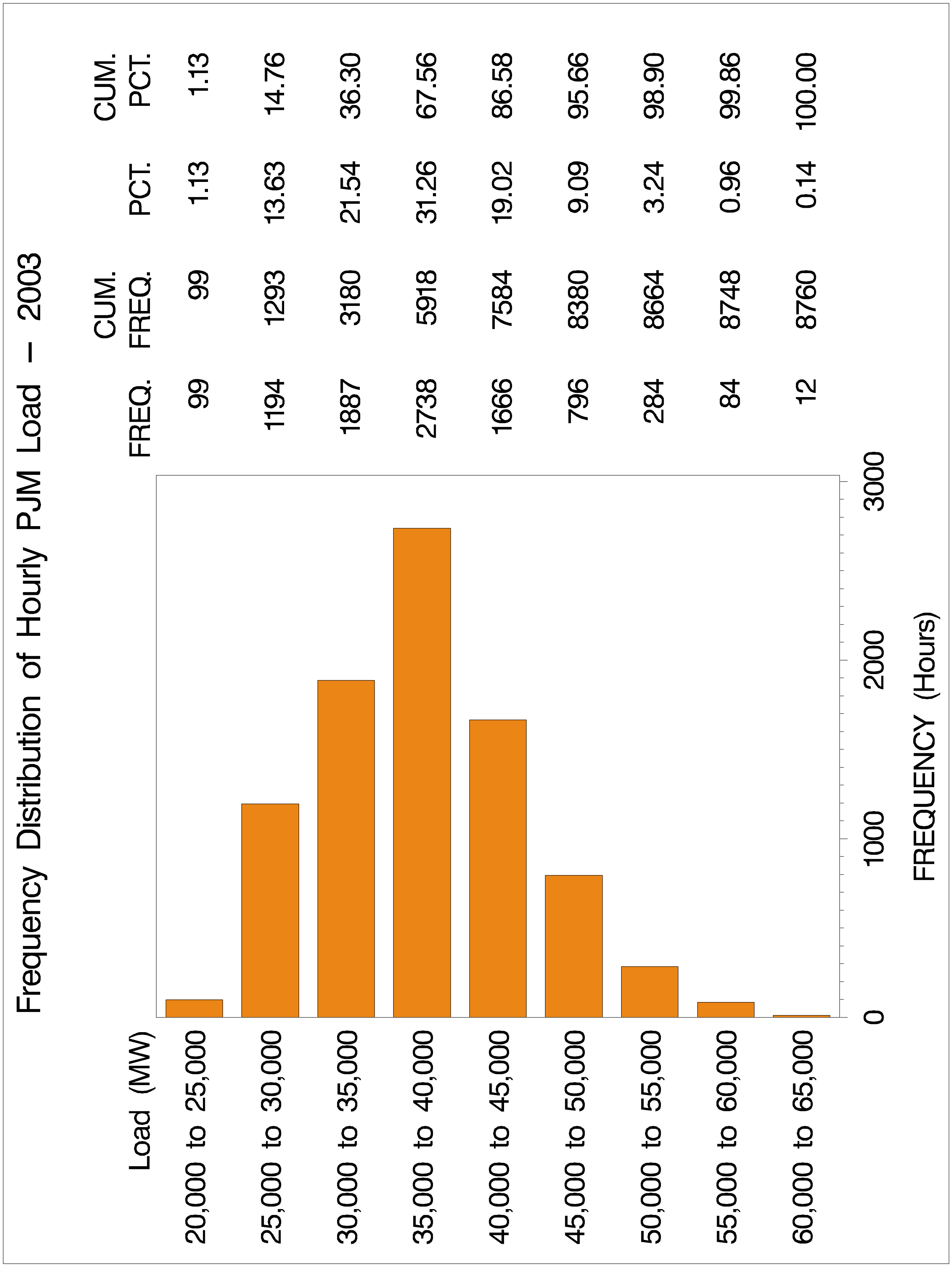


Figure C-11 Frequency Distribution of Hourly PJM Load: 2002



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	9	9	0.10	0.10
20,000 to 25,000	443	452	5.06	5.16
25,000 to 30,000	1809	2261	20.65	25.81
30,000 to 35,000	2306	4567	26.32	52.13
35,000 to 40,000	2155	6722	24.60	76.73
40,000 to 45,000	1026	7748	11.71	88.44
45,000 to 50,000	490	8238	5.59	94.03
50,000 to 55,000	248	8486	2.83	96.86
55,000 to 60,000	192	8678	2.19	99.05
60,000 to 65,000	83	8761	0.95	100.00

Figure C-12 Frequency Distribution of Hourly PJM Load: 2003



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 to 25,000	99	99	1.13	1.13
25,000 to 30,000	1194	1293	13.63	14.76
30,000 to 35,000	1887	3180	21.54	36.30
35,000 to 40,000	2738	5918	31.26	67.56
40,000 to 45,000	1666	7584	19.02	86.58
45,000 to 50,000	796	8380	9.09	95.66
50,000 to 55,000	284	8664	3.24	98.90
55,000 to 60,000	84	8748	0.96	99.86
60,000 to 65,000	12	8760	0.14	100.00

In comparing the figures, one can see that, during each year, LMP was most frequently in the interval $10 per MWh to $20 per MWh. In 2003, however, LMP occurred in the interval from $20 per MWh to $30 per MWh nearly as frequently (24 percent in the $10 to $20 interval and 22 percent in the $20 to $30 interval). In 2003, LMP was less than $60 per MWh for 83 percent of the hours and less than $100 per MWh for 98 percent of the hours. LMP was $150 per MWh or greater for 11 hours (0.07 percent of the hours) in 2003.

Frequency Distribution of Load

Figure C-7, Figure C-8, Figure C-9, Figure C-10, Figure C-11 and Figure C-12 provide the frequency distribution of PJM load by number of hours, for 1998, 1999, 2000, 2001, 2002 and 2003. In 2003, the most frequently occurring load interval was 35,000 MW to 40,000 MW (31 percent of the hours). These figures show that, before the PJM Western Region was added in April 2002, the most frequently occurring load interval had been 30,000 MW to 35,000 MW. In 2003, load was less than 35,000 MW for 36 percent of the hours, less than 50,000 MW for 96 percent of the hours and less than 60,000 MW for all but 12 hours (0.14 percent of the hours). In 2002, load was less than 35,000 MW for 52 percent of the hours, less than 50,000 MW for 94 percent of the hours and less than 60,000 MW for 99 percent of the hours. The peak demand for the year occurred on August 22, 2003, with a peak demand of 61,500 MW.

Off-Peak and On-Peak Load

Table C-1 presents summary load statistics for 1998 to 2003 for the off-peak and on-peak hours, while Table C-2 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, excluding NERC holidays. As one can see from the table, in 2003, on-peak load was about 20 percent higher than off-peak load. During the previous five years, on-peak load had been about 30 percent higher than off-peak load, while median peak load had ranged from 20 percent to 30 percent higher. With the addition of the PJM Western Region, average load during on-peak hours in 2003 was about 4 percent higher than in 2002. Off-peak load in 2003 was 6 percent higher than in 2002.

Table C-1 Off-Peak and On-Peak Load: 1998 to 2003 (in MW)

Year	Average Load			Median Load			Standard Deviation		
	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak	On-Peak/ Off-Peak
2003	33,595	41,755	1.2	32,971	40,802	1.2	5,546	5,424	1.0
2002	31,584	40,102	1.3	30,457	38,243	1.3	6,044	7,400	1.2
2001	26,804	34,303	1.3	26,433	33,076	1.3	4,225	4,851	1.1
2000	26,921	33,766	1.3	26,327	32,771	1.2	4,453	4,226	0.9
1999	26,409	33,291	1.3	25,795	31,987	1.2	4,862	4,870	1.0
1998	25,268	32,344	1.3	24,728	31,081	1.3	4,091	4,388	1.1

Table C-2 Year-Over-Year Percent Change in Load: 1998-1999 through 2002-2003

Year	Average Load		Median Load		Standard Deviation	
	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak
2003	6.4%	4.1%	8.3%	6.7%	-8.2%	-26.7%
2002	17.8%	16.9%	15.2%	15.6%	43.1%	52.5%
2001	-0.4%	1.6%	0.4%	0.9%	-5.1%	14.8%
2000	1.9%	1.4%	2.1%	2.5%	-8.4%	-13.2%
1999	4.5%	2.9%	4.3%	2.9%	18.8%	11.0%
1998	-	-	-	-	-	-

Off-Peak and On-Peak Load-Weighted LMP: 2002 and 2003

Table C-3 shows load-weighted average LMP for 2002 and 2003 during off-peak and on-peak periods. In 2002, the on-peak, load-weighted LMP was 80 percent greater than the off-peak LMP, while in 2003 it was 60 percent greater. On-peak, load-weighted, average LMP in 2003 was 25.6 percent higher than in 2002. Off-peak, load-weighted LMP in 2003 was 40.9 percent higher than in 2002. Similarly, both on-peak and off-peak median LMP were higher in 2003 than in 2002, by 42.5 percent and 26.6 percent, respectively. Dispersion in load-weighted LMP, as indicated by standard deviation, was 26.1 percent lower in 2003 than in 2002 during on-peak hours, while the standard deviation was 69.5 percent higher in 2003 than in 2002 during off-peak hours.

Table C-3 Off-Peak and On-Peak, Load-Weighted LMP for 2002 and 2003 (in Dollars per MWh)

	2003			2002			% Change 2002 to 2003	
	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak
Average LMP	$31.75	$49.97	1.6	$22.53	$39.79	1.8	40.9%	25.6%
Median LMP	$22.52	$46.08	2.0	$17.79	$32.34	1.8	26.6%	42.5%
Standard Deviation	$23.53	$23.88	1.0	$13.88	$32.33	2.3	69.5%	-26.1%

Fuel-Cost Adjustment

Fuel costs for 2002 and 2003 were taken from various published sources. Coal prices were obtained from The Energy Argus and adjusted for transportation costs. Both natural gas and petroleum prices were obtained from Platts and adjusted for transportation costs.

The price index for each fuel was calculated as a chain-weighted index, where the weights are the number of MW generated in each month of 2002 and 2003 for which the price was determined by the marginal generating unit firing the indicated fuel. First, an index was calculated using 2002 fuel-specific MW as the weights: (year 2003 fuel-specific prices times year 2002 fuel-specific MW) divided by (year 2002 fuel-specific prices times year 2002 fuel-specific MW). Second, an index was calculated using year 2003 fuel-specific MW as the weights: (year 2003 fuel-specific prices times year 2003 fuel-specific MW) divided by (year 2002 fuel-specific prices times year 2003 fuel-specific MW). The two indices were then chain-weighted by calculating their geometric mean. Each year 2003 hourly LMP for a month was then divided by the chain-weighted price index for that month to derive the fuel-cost-adjusted LMP. Fuel-cost-adjusted LMPs were then weighted by load to derive the load-weighted, fuel-cost-adjusted LMP.

LMP During Constrained Hours: 2002 and 2003

Figure C-13 shows the number of constrained hours during each month in 2002 and 2003 and the average number of constrained hours per month for each year.[3] There were 5,230 constrained hours in 2002 and 4,855 in 2003, a decrease of approximately 7 percent. Figure C-13 also shows that the average number of constrained hours per month was slightly less in 2003 than in 2002, with 405 per month in 2003 versus 436 per month in 2002.

Table C-4 presents summary statistics for load-weighted average LMP during constrained hours in 2002 and 2003. During constrained hours, the average, load-weighted LMP was 24 percent higher in 2003 than it was for constrained hours in 2002. During constrained hours, the median, load-weighted LMP was 43.1 percent higher in 2003 than in 2002, and the dispersion of LMP, as shown by the standard deviation, was 24.6 percent lower in 2003 than in 2002.

Table C-4 2002 and 2003 Load-Weighted Average LMP During Constrained Hours (in Dollars per MWh)

	2003	2002	Percent Change
Average LMP	$45.77	$36.90	24.0%
Median LMP	$41.77	$29.18	43.1%
Standard Deviation	$24.81	$30.93	-24.6%

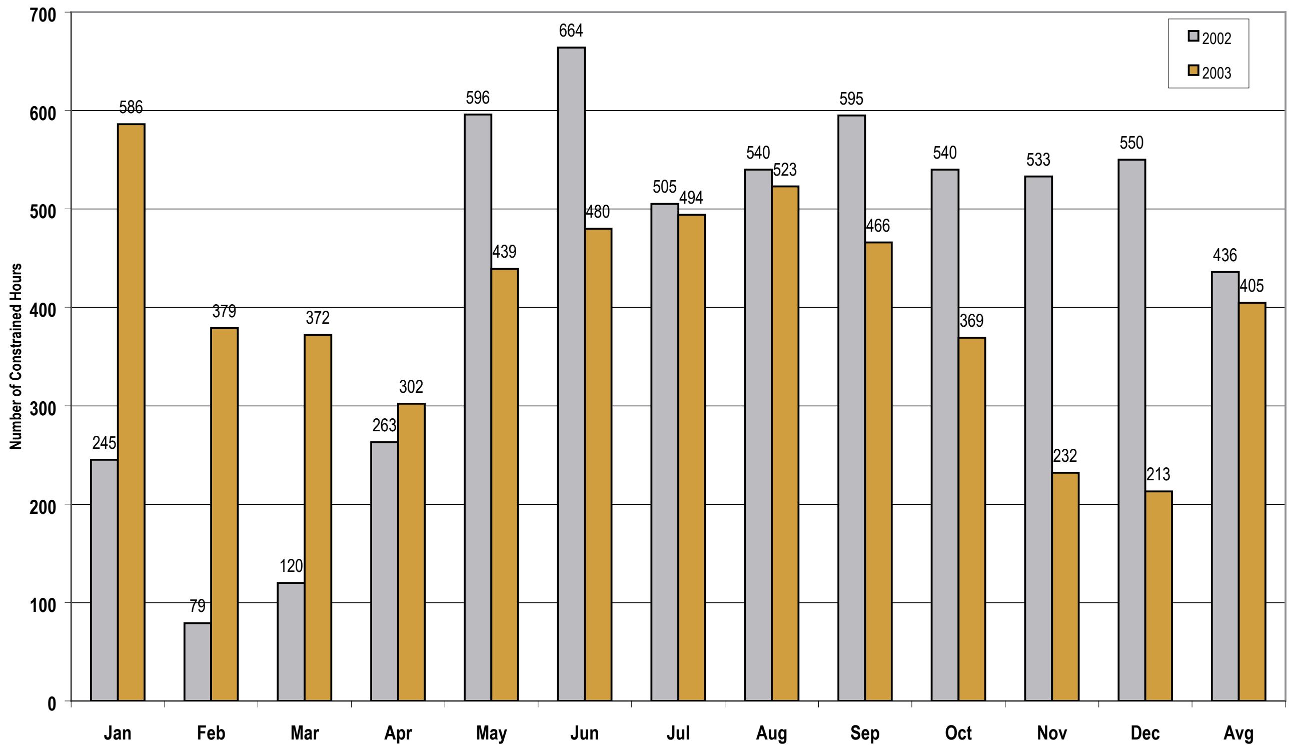
Table C-5 provides a comparison of load-weighted average LMP during constrained and unconstrained hours for the two years. In 2003, average load-weighted LMP during constrained hours was 31.2 percent higher than average load-weighted LMP during unconstrained hours. The comparable number for 2002 was 16.8 percent.

Table C-5 2002 and 2003 Load-Weighted Average LMP During Constrained and Unconstrained Hours (in Dollars per MWh)

	2003			2002		
	Unconstrained Hours	Constrained Hours	Percent Difference	Unconstrained Hours	Constrained Hours	Percent Difference
Average LMP	$34.87	$45.77	31.2%	$31.60	$36.90	16.8%
Median LMP	$25.24	$41.77	65.5%	$23.41	$29.18	24.6%
Standard Deviation	$24.84	$24.81	-0.1%	$26.74	$30.93	15.7%

3 For purposes of this discussion, a constrained hour is defined as one in which the difference in LMP between at least two buses in that hour is greater than $1.00.

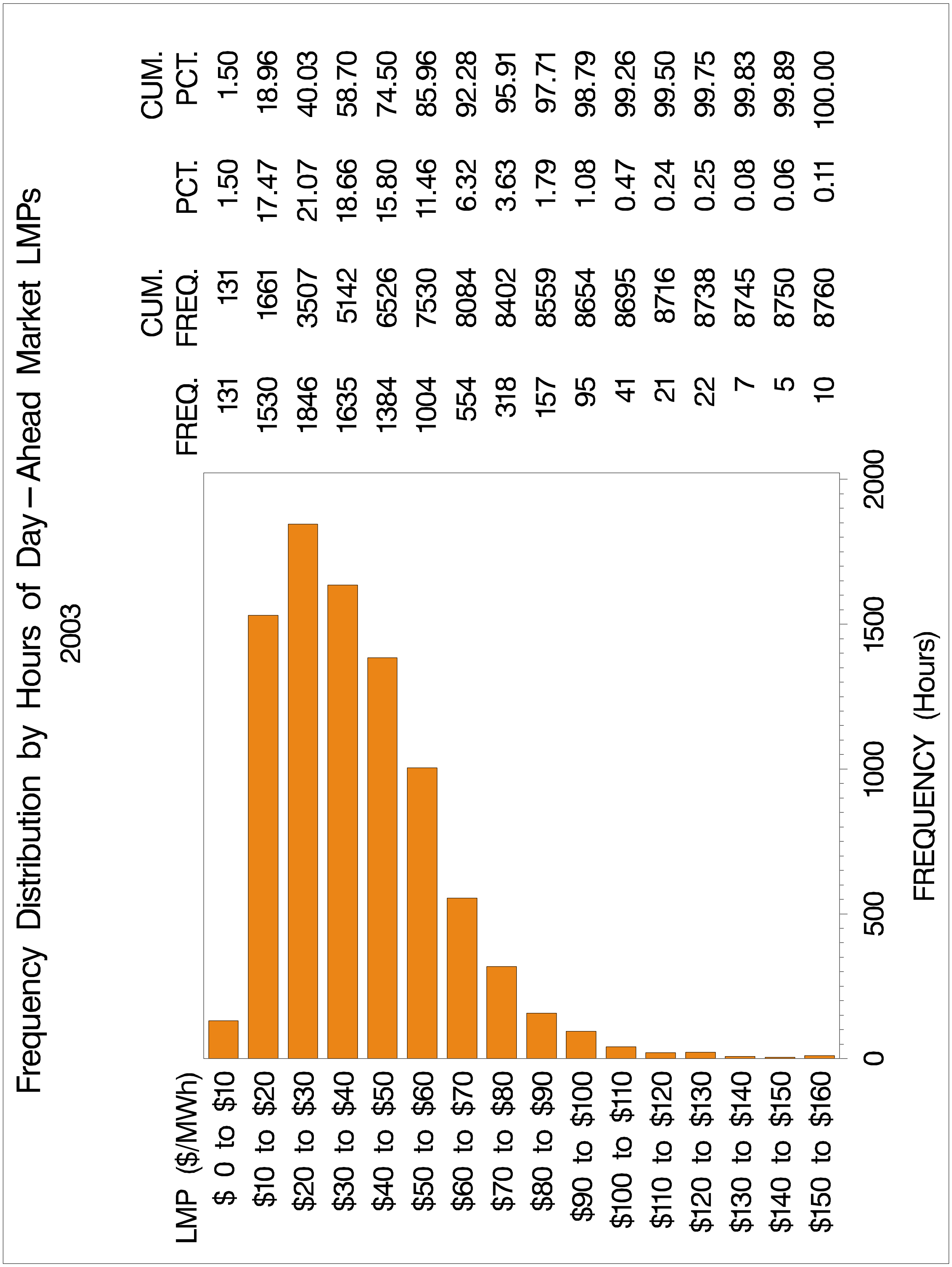
Figure C-13 PJM Constrained Hours: 2002 and 2003



Day-Ahead and Real-Time Prices

As noted earlier, real-time prices are only slightly lower than day-ahead prices on average, but real-time prices show greater dispersion. This pattern of average systemwide LMP price distribution for 2003 can be seen in Figure C-6 and Figure C-14. Together they show the frequency distribution by hours for the two markets. In PJM's Real-Time Market, both the $10-per-MWh to $20-per-MWh, and $20-per-MWh to $30-per-MWh intervals occurred with nearly equal frequency, 24 percent and 22 percent of the hours, respectively. The most frequently occurring price interval in the PJM Day-Ahead Energy Market was the $20-per-MWh to $30-per-MWh interval with 21 percent of the hours. The $30-per-MWh to $40-per-MWh interval was the next most frequent with 19 percent of the hours, only slightly above the $10-per-MWh to $20-per-MWh interval which occurred during 17 percent of the hours. In the Real-Time Market, prices were less than $30 per MWh for 49 percent of the hours, while prices were less than $30 per MWh in the Day-Ahead Market for 40 percent of the hours. Cumulatively, prices were less than $40 per MWh for 61 percent of the hours in the Real-Time Market and 59 percent of the hours in the Day-Ahead Market; less than $50 per MWh for 73 percent of the hours in the Real-Time Market and 75 percent of the hours in the Day-Ahead Market; less than $60 per MWh for 83 percent of the hours in the Real-Time Market and 86 percent of the hours in the Day-Ahead Market. In the Real-Time Market, prices were above $150 per MWh for 11 hours (0.07 percent of the hours), reaching a high for the year of $210.83 per MWh on February 16. In the Day-Ahead Market, prices were above $150 per MWh for 10 hours (0.11 percent of the hours), but reached a high for the year of $155.71 per MWh on March 11.

Figure C-14 Frequency Distribution by Hours of Day-Ahead Market LMP: 2003



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	131	131	1.50	1.50
$10 to $20	1530	1661	17.47	18.96
$20 to $30	1846	3507	21.07	40.03
$30 to $40	1635	5142	18.66	58.70
$40 to $50	1384	6526	15.80	74.50
$50 to $60	1004	7530	11.46	85.96
$60 to $70	554	8084	6.32	92.28
$70 to $80	318	8402	3.63	95.91
$80 to $90	157	8559	1.79	97.71
$90 to $100	95	8654	1.08	98.79
$100 to $110	41	8695	0.47	99.26
$110 to $120	21	8716	0.24	99.50
$120 to $130	22	8738	0.25	99.75
$130 to $140	7	8745	0.08	99.83
$140 to $150	5	8750	0.06	99.89
$150 to $160	10	8760	0.11	100.00

Off-Peak and On-Peak LMP

Table C-6 shows average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Markets. Day-ahead and real-time on-peak average LMPs were about 70 percent higher than the corresponding off-peak average LMP. The real-time peak average LMP was 1.7 percent lower than the day-ahead peak average LMP. Median LMPs during on-peak hours were 94 percent and 111 percent higher in the Day-Ahead and Real-Time Markets, respectively, than median LMPs during off-peak hours. The day-ahead median on-peak LMP was also 2.9 percent higher than the real-time median on-peak 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 Market as compared to the Day-Ahead Market, during both on-peak and off-peak periods (9 percent and 39 percent compared to 8 percent and 25 percent, respectively). The difference reflects the larger positive skewness in the Real-Time Market. During on-peak hours, the standard deviation in the Real-Time Market was about 23 percent higher than in the Day-Ahead Market while it was 25 percent higher during off-peak hours.

Figure C-15 and Figure C-16 show the difference between real-time and day-ahead LMP in 2003 during the on-peak and off-peak hours, respectively. The average difference between real-time and day-ahead LMP during on-peak hours was only $0.81 per MWh (day-ahead LMP higher than real-time LMP). By contrast, during off-peak hours, the average difference between real-time and day-ahead LMP was $0.13 per MWh (day-ahead LMP higher than the real-time LMP). The figures also indicate that the largest price differences between the real-time and day-ahead LMPs, during both the off-peak and on-peak periods, occurred during the first quarter of 2003.

Table C-6 2003 Off-Peak and On-Peak LMP (in Dollars per MWh)

	Day-Ahead			Real-Time			% Change Day-Ahead to Real-Time	
	Off-Peak	On-Peak	On-Peak/ Off-Peak	On-Peak	On-Peak	On-Peak/ Off-Peak	On-Peak	On-Peak
Average LMP	$29.45	$49.35	1.68	$29.32	$48.54	1.66	-0.4%	-1.7%
Median LMP	$23.64	$45.76	1.94	$21.10	$44.45	2.11	-10.8%	-2.9%
Standard Deviation	$17.66	$19.05	1.08	$22.10	$23.52	1.06	25.1%	23.5%

LMP During Constrained Hours: Day-Ahead and Real-Time Markets

Figure C-17 shows the number of constrained hours in each month for the Day-Ahead and Real-Time Markets and the average number of constrained hours for 2003.[4] Overall, there were 4,855 constrained hours in the Real-Time Market and 7,874 constrained hours in the Day-Ahead Market, 62 percent more. Figure C-17 shows that in every month of 2003 the number of constrained hours in the Day-Ahead Market exceeded those in the Real-Time Market. On average for the year, the Day-Ahead Market had 62 percent more constrained hours than the Real-Time Market.

4 For purposes of this discussion, a constrained hour is defined as one in which the difference in LMP between at least two buses in that hour is greater than $1.00.

Figure C-15 Hourly Real-Time LMP minus Day-Ahead LMP: 2003 On-Peak Hours

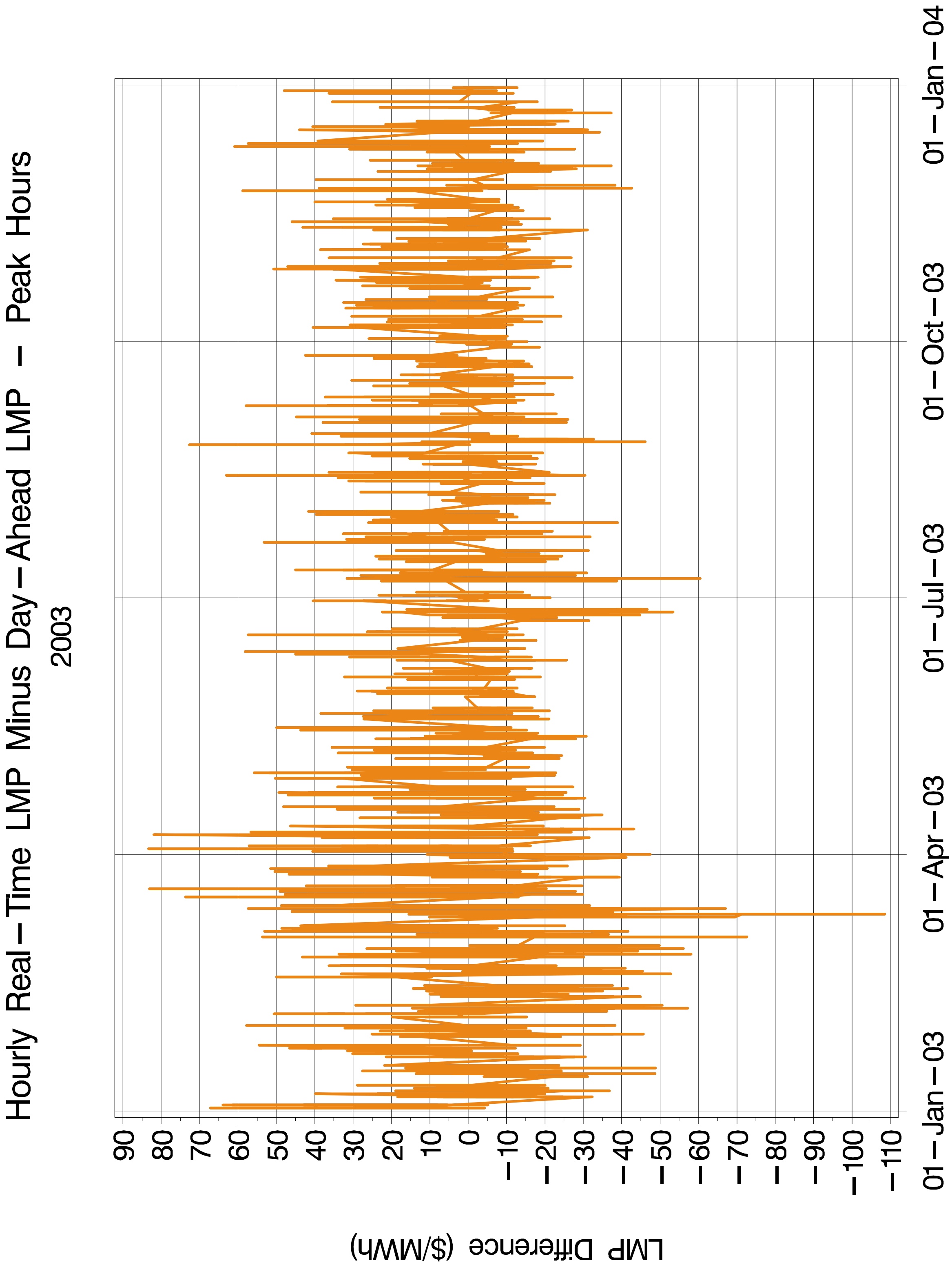


Figure C-16 Hourly Real-Time LMP minus Day-Ahead LMP: 2003 Off-Peak Hours

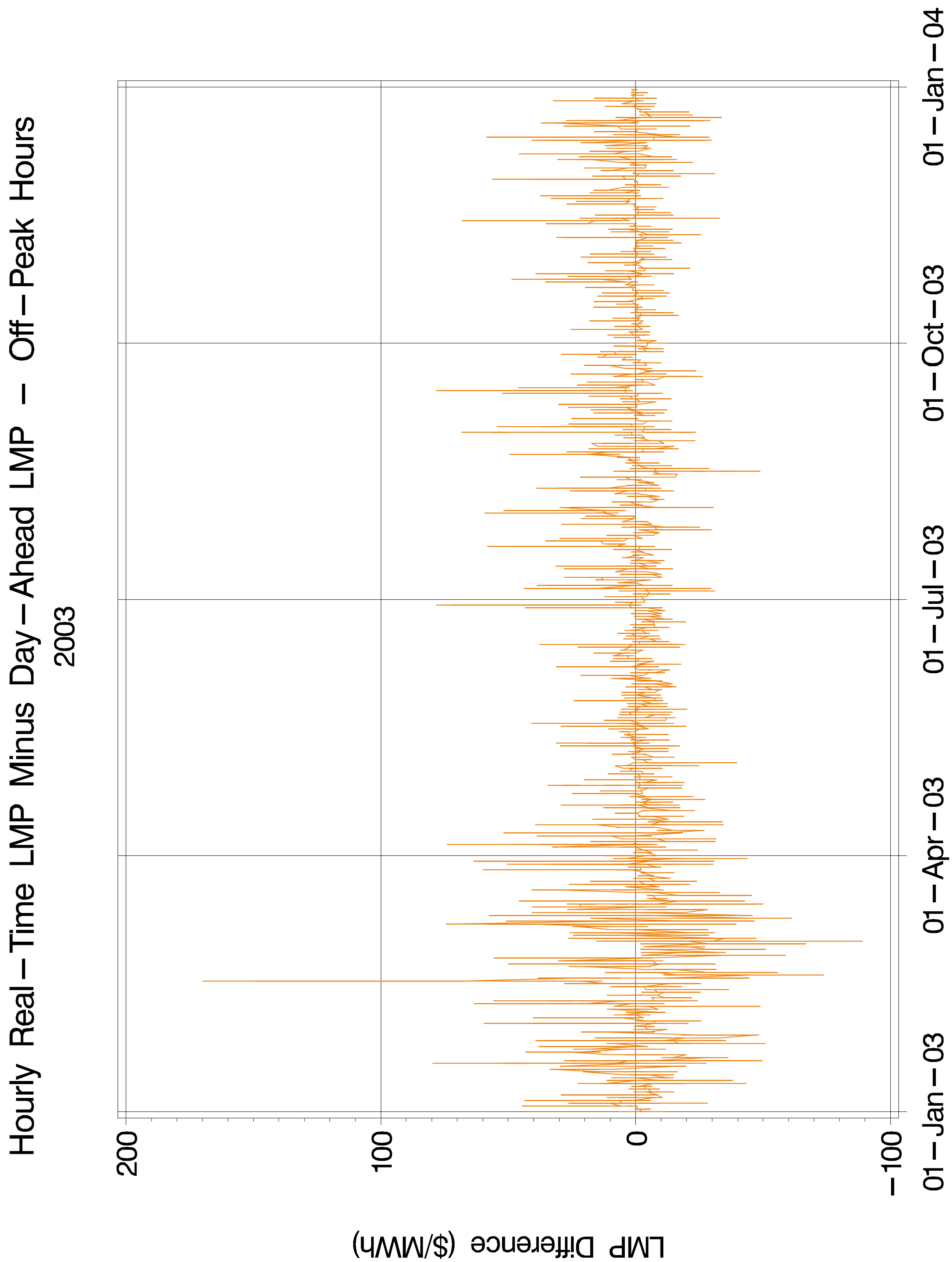


Figure C-17 Real-Time and Day-Ahead Market-Constrained Hours: 2003

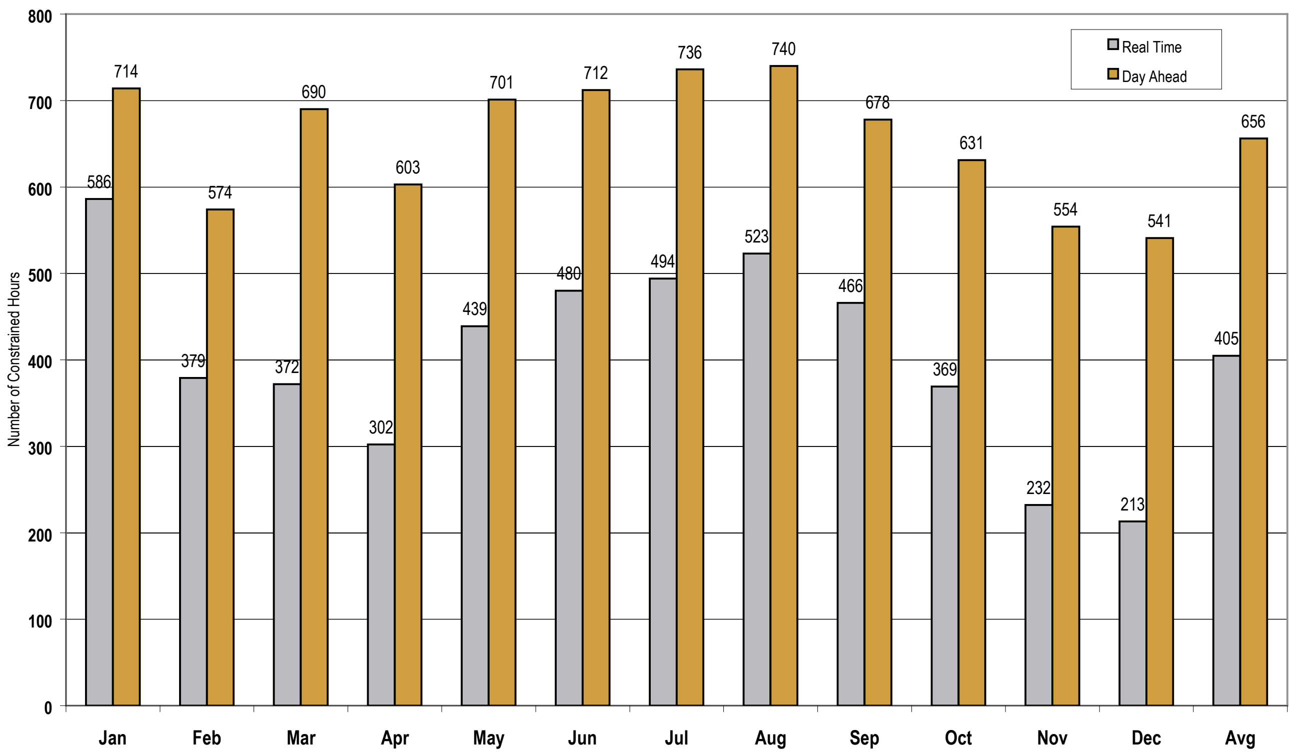


Table C-7 shows average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Markets. In the Day-Ahead Market, average LMP during constrained hours was 32.7 percent higher than average LMP during unconstrained hours. In the Real-Time Market, average LMP during constrained hours was 34.3 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 8.8 percent higher in the Real-Time Market than in the Day-Ahead Market. Both markets exhibited greater price dispersion during constrained hours than during unconstrained hours.

Table C-7 2003 LMP During Constrained and Unconstrained Hours (in Dollars per MWh)

	Day-Ahead			Real-Time		
	Unconstrained Hours	Constrained Hours	Percent Change	Unconstrained Hours	Constrained Hours	Percent Change
Average LMP	$29.93	$39.71	32.7%	$32.15	$43.19	34.3%
Median LMP	$20.19	$36.44	80.5%	$22.65	$38.26	68.9%
Standard Deviation	$21.97	$20.47	-6.8%	$23.80	$24.33	2.2%

Table C-7 shows that average LMP in the Day-Ahead Market during constrained hours was 2.6 percent higher than the overall average LMP for the Day-Ahead Market, while average LMP during unconstrained hours was 22.7 percent lower. In the Real-Time Market, average LMP during constrained hours was 12.9 percent higher than the overall average LMP for the Real-Time Market, while average LMP during unconstrained hours was 16 percent lower.

Appendix D – Capacity Markets

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 PJM Energy Markets. Adequate capacity resources, equal to 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.[1] 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.

The "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Control Area" (RAA) states that as competitive markets evolve the purpose of capacity obligations is to "ensure that adequate Capacity Resources will be planned and made available to provide reliable service to loads within the PJM Control Area, to assist other Parties during Emergencies and to coordinate planning of Capacity Resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace."[2] When the PJM Western Region joined PJM, a new reliability assurance agreement was developed, the "PJM-West Reliability Assurance Agreement Among Load-Serving Entities in the PJM-West Region," that specified the Capacity Market rules initially implemented in the PJM Western Region.

Under the RAA for both the PJM Mid-Atlantic and Western Regions, 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 installed capacity or capacity imports.

On April 1, 2002, the PJM Western Region joined PJM. On June 1, 2003, the PJM Western Region Capacity Market and the PJM Mid-Atlantic Region Capacity Market were combined into a single market, referred to as the PJM Capacity Market. The PJM Capacity Market currently operates under the same common set of rules previously associated with the PJM Mid-Atlantic Region alone.

1 The first Capacity Credit Markets (CCMs) were run in late 1998, with an effective date of January 1, 1999.
2 "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Control Area," revised March 21, 2000 (RAA), Article 2 – "Purpose," page 8.

Capacity Obligations

For the PJM Mid-Atlantic and Western Regions, an annual load forecast is used to determine the forecast peak load for each region. These forecast peak load values are further adjusted to determine capacity obligations.

- **PJM Mid-Atlantic Region.** In the PJM Mid-Atlantic Region, the adjusted forecast peak load value[3] is multiplied by the forecast pool requirement (FPR) to determine the unforced capacity obligation. The FPR is equal to one plus a reserve margin, multiplied by the PJM Mid-Atlantic Region unforced outage factor. An LSE's unforced capacity obligation is its forecast peak load multiplied by the FPR. The FPR is set for each planning period which commences every June 1.

- **PJM Western Region.** Prior to June 1, 2003, in the PJM Western Region, the forecast peak load was multiplied by 6 percent to determine, for each entity, its maximum daily available capacity obligation (DACO). Unlike the PJM Mid-Atlantic Region in which the unforced capacity obligation is set annually and must be met on a daily basis, the DACO of the PJM Western Region was set daily, based on the daily load forecast, and had to be met on a daily basis. The DACO could not exceed 106 percent of the forecast period peak load (FPPL).

Beginning June 1, 2003, the PJM Mid-Atlantic and Western Regions' Capacity Markets were combined into a single, systemwide PJM Capacity Market with rules identical to those for the PJM Mid-Atlantic Region's market alone. Those rules now provide the framework within which LSEs throughout the PJM service area meet their capacity obligations.

Meeting Capacity Obligations

Two Capacity Markets before June 1, 2003

- **PJM Mid-Atlantic Region.** In the PJM Mid-Atlantic Region (then known as PJM-Eastern Region), an LSE's load could change on a daily basis as customers switched suppliers. The unforced capacity position of every such LSE was calculated daily when its capacity resources were compared to its capacity obligation to determine whether any LSE was short of capacity resources. Deficient entities had to contract for capacity resources to satisfy their deficiency. Any LSE that remained deficient had to pay an interval penalty equal to the capacity deficiency rate (CDR) times the number of days in an interval.[4] If an LSE was short because of a short-term load increase, it paid only the daily penalty until the end of the month. In no case was a deficient LSE charged more than the CDR multiplied by the number of days in the interval multiplied by each MW of deficiency.

- **PJM Western Region.** In the PJM Western Region (then known as PJM-West), an LSE's load changed daily, both because of customers switching suppliers and because of changing daily load forecasts. In the PJM Western Region only currently available units could be used to meet the DACO. If an LSE remained deficient, it was charged the PJM Western Region CDR (then set at $12,755.29 per MW-day), for each deficiency day. In no circumstance was an LSE required to pay more than $63,776.45 for each deficient MW during the period beginning June 1, 2002, and ending May 31, 2003. LSEs were permitted to pay only a daily CDR, then set at $174.73 per MW-day, for their deficiency if they chose to carry a portfolio of installed capacity valued at 118 percent of their respective forecast peak period load.

One Capacity Market after June 1, 2003

On June 1, 2003, the PJM Mid-Atlantic Capacity Market and the PJM Western Region Capacity Market became one market, the PJM Capacity Market, whose rules are the same as those that had governed the PJM Mid-Atlantic Region Capacity Market prior to June 1, 2003. Beginning June 1, 2003, any PJM LSE's load may change on a daily basis as customers switch suppliers. The unforced capacity position of every such LSE is calculated daily when

3 Adjusted for active load-management (ALM) and local diversity.

4 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 $174.73 per MW-day, effective June 1, 2002, and to $170.96 per MW-day, effective June 1, 2003.

its capacity resources are compared to its capacity obligation to determine whether 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 CDR (currently $170.96 per MW-day), times the number of days in an interval. 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 times each MW of deficiency.

Capacity Resources

Capacity resources are defined as MW of net generating capacity meeting specified PJM criteria. They may be located within or outside of the service area, but they must be committed to serving specific PJM loads. 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.[5]

Capacity resources 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, defined in terms of unforced capacity and measured in MW.

- **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 PJM service area.

- **Capacity Credit Markets.** Market purchases may be made from PJM Daily, Monthly, Multimonthly or Interval Capacity Credit Markets.

The sale of a generating unit as a capacity resource within PJM entails obligations for the generation owner:

- **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 and sold outside PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures.[6] 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 service area. When PJM invokes the recall right, the energy supplier is paid the PJM real-time, spot market energy price.

- **Day-Ahead Energy Market Offer Requirement.** Owners of 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, resource owners must provide the offered energy at the offered price. This energy can be provided either from the specific unit offered or by purchasing the energy bilaterally, or at the spot market price, and reselling the energy at the offer price.

- **Deliverability.** In order to qualify as a capacity resource, energy from the generating unit must be deliverable to load on the PJM system. Capacity resources must be deliverable, 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 capacity resources located outside the metered boundaries of the PJM region and used to meet an accounted-for obligation, capacity and energy must be delivered to the metered boundaries of the PJM region through firm transmission service.

5 See RAA, "Capacity Resources," page 2.

6 PJM emergency procedures are defined in the "PJM Manual for Emergency Operations."

- **Generator Outage Reporting Requirement.** Owners of capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.

- **Financial Transmission Right.** A Financial Transmission Right (FTR) was, prior to implementation of the ARR allocation rules on June 1, 2003, available to load only if a specific capacity resource was identified as the source of the delivered energy.[7] Since a capacity credit is not unit-specific, it could not be the basis for an FTR. Under the current ARR allocation rules, an ARR is available to load only if a specific capacity resource is identified as the source of the delivered energy. The next modification of the ARR allocation rules, which will be effective June 1, 2004, breaks the link between capacity resources and ARRs. After June 1, 2004, customers may request ARRs from the resources that were historically designated to serve load in a transmission zone or a load aggregate.

The first three obligations associated with sale of capacity resources are clearly essential to the definition of a capacity resource and contribute directly to system reliability.

Market Dynamics

RAA procedures determine PJM's total capacity obligation and thus the total demand for capacity credits. The RAA includes rules for allocating total capacity obligation to individual LSEs. This obligation is equivalent to a fixed total demand, net of active load-management (ALM), bilateral contracts and self-supply, that must be bid into PJM's Interval, Multimonthly, Monthly or Daily Capacity Credit Markets. Demand for capacity credits in daily markets is the residual demand after capacity credits are purchased in PJM's longer term Capacity Credit Markets or through bilateral transactions.

The supply of capacity credits in all PJM Capacity Credit Markets is a function of:

- Physical capacity in the PJM service area;
- Prices in external energy and capacity markets;
- Prices in the PJM Energy and Capacity Markets;
- Capacity resource imports; and
- Transmission service availability and price.

While physical generating units in PJM are the primary source of capacity resources, capacity resources can be delisted, i.e., exported, from PJM and imported from regions external to PJM, subject to transmission limitations. It is the ability to export and to import capacity resources that makes capacity supply in PJM a function of price in both internal and external capacity and energy markets.

In capacity markets, as in other markets, market power is the ability of a market participant to increase market price above the competitive level. The competitive market price is the marginal cost of producing the last unit of output, assuming no scarcity and including opportunity costs. For capacity, the opportunity cost of selling into the PJM Capacity Market is the additional revenue foregone from 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 the alternative opportunities available to the generation owner. If an owner is considering whether to sell a capacity resource for a year, marginal costs would include the incremental costs of maintaining the unit so that it can qualify as a capacity resource and any relevant

7 An ARR is an Auction Revenue Right.

opportunity costs. If an owner is considering whether to sell a capacity resource for a day, the only relevant costs are the opportunity costs. 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 E — Glossary

Active load management (ALM)	ALM is end-use customer load which can be interrupted at the request of PJM. Such 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 maintaining reliable operation of the transmission provider's transmission system in accordance with good utility practice.
Area control error (ACE)	The ACE of the PJM control area is the actual net interchange minus the biased scheduled net interchange and a frequency deviation component.
Auction Revenue Right (ARR)	Financial instrument entitling its holder to FTR auction revenue based on LMP differences across a specific path in the annual FTR auction.
Average hourly unweighted LMP	Average hourly LMP is calculated by averaging hourly LMP without any weighting.
Balancing market evaluation (BME)	The NYISO defines BME as, "An evaluation performed by the NYISO for the hour in which the dispatch occurs. The BME begins seventy-five (75) minutes before the beginning of the hour in which dispatch occurs. Based upon the Day-Ahead commitment and updated Load forecasts and Generator schedules, BME will assess new Bids for the Locational Based Marginal Pricing ("LBMP") Markets and requests for new Bilateral Transaction schedules for the Dispatch Hour to which the Security Constrained Unit Commitment (SCUC) applies. BME will redispatch Internal Generators, schedule External Generators, schedule new Bilateral Transactions if feasible, update Desired Net Interchanges if needed, and Reduce or Curtail Bilateral Transactions with non-Firm and Firm Transmission Service as needed for the dispatch Hour for which the SCUC applies."[1]
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	Agreement between two parties for the sale and delivery of a service.

1 New York Independent System Operator, "Definitions/Glossary" http://www.nyiso.com/services/training/glossary/index.html (23 February 2004).

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 generation site equalling 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 RTEPP capacity resource project requests that are received during a particular timeframe. There are typically two queues per year and they are referred to alphabetically.
Combined-cycle (CC)	A generating unit generally consisting of a gas-fired turbine 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.
Decrement bids	Financial offers to purchase specified amounts of MW in the Day-Ahead 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 OI.
End-use customer	Any customer purchasing electricity at retail.
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 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.
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 sum of all LSE's individual excess capacity, or the excess of unforced capacity above unforced capacity obligation. The term is referred to as "Accounted-for Excess" in the "PJM Accounted-For Obligation Manual" (Manual 17).
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.
Increment offers	Financial offers in the Day-Ahead market to supply specified amounts of MW at or above a given price.
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.
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.
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 either a market supplier, a market buyer or both. Market buyers and market sellers are members that have met reasonable creditworthiness standards established by the OI. 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.
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.
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 LSE obligations.
Net exports (capacity)	Capacity exports (or delists) less capacity imports.

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 is 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 holiday (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 7:00 a.m.
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 8:00 a.m. until the hour ending at 11:00 p.m.
PJM member	Any entity that has completed an application and satisfies the requirements of PJM to conduct business with the PJM OI 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	Represents 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.
Regional Transmission Expansion Planning Protocol	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.
Residual capacity	Capacity that is unsold after markets clear.
Residual supply index (RSI)	RSI measures the percent of supply remaining in the market net of each generation owner's supply. RSI for generator "i" is: $[(\text{Supply}_m - \text{Supply}_i) / (\text{Demand}_m)]$ Where Supply_m is total supply in an energy market plus net imports. Supply_i is the supply owned by the generation owner "i" and Demand_m is total market demand.

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.
Sources and sinks	Sources are the injection end of a transmission transaction. Sinks are the withdrawal end of a transaction.
Spinning reserve	Reserve capability which is required in order to enable an area to restore its tie-lines to the precontingency state within 10 minutes of a contingency which 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.
System lambda	The cost to the PJM system of generating the next unit of output.
Unforced capacity	Installed capacity adjusted by forced outage rates.

Appendix F — List of Acronyms

ACE	Area control error
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEP	American Electric Power Company, Inc.
ALM	Active Load Management
APS	Allegheny Power
ARR	Auction Revenue Rights
BGE	Baltimore Gas and Electric Company
BGS	Basic Generation Service
BME	Balancing Market Evaluation
CCM	Capacity Credit Market
CC	Combined cycle
CDR	Capacity Deficiency Rate
CDTF	Cost Development Task Force
CPS	Control Performance Standard
CT	Combustion turbine
CUM FREQ	Cumulative frequency
CUM PCT	Cumulative percent
DA	Day ahead
DCS	Disturbance control standard

DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva North
DPLS	Delmarva South
DSR	Demand Side Response
ECAR	East Central Area Reliability Council
EFORd	Equivalent demand forced outage rate
EHV	Extra high voltage
FE	FirstEnergy Corp.
FERC	United States Federal Energy Regulatory Commission
FPPL	Forecast period peak load
FPR	Forecast pool requirement
FREQ	Frequency
FTR	Financial Transmission Rights
HHI	Herfindahl-Hirschman Index
ICAP	Installed capacity
IMO	Independent Electricity Market Operator for Ontario
IPP	Independent Power Producer
ISO	Independent System Operator
JCPL	Jersey Central Power & Light Company
LMP	Locational marginal price

LSE	Load-serving entity
LTE	Long-term emergency
MAIN	Mid-America Interconnected Network, Inc.
MAAC	Mid-Atlantic Area Council
MAPP	Mid-Continent Area Power Pool
MCP	Market-clearing price
Met-Ed	Metropolitan Edison Company
MEW	Western subarea of Metropolitan Edison Company
MP	Market participant
MMU	PJM Market Monitoring Unit
NERC	North American Electric Reliability Council
NYISO	New York Independent System Operator
OA	PJM Operating Agreement
OASIS	Open Access Same-Time Information System
ODEC	Old Dominion Electric Cooperative
OI	PJM Office of the Interconnection
PCT	Percent
PE	PECO zone
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
PEPCO	Pepco (formerly Potomac Electric Power Company)

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/IMO	PJM/IMO interface pricing point
PJM/NYIS	PJM/NYISO interface pricing point
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
RECO	Rockland Electric Company zone
RMCP	Regulation Market clearing price
RSI	Residual supply index
RT	Real time
RTEPP	Regional Transmission Expansion Planning Protocol
SCPA	Southcentral Pennsylvania subarea
SEPJM	Southeastern PJM subarea
SFT	Simultaneous feasibility test

SMECO	Southern Maryland Electric Cooperative
SNJ	Southern New Jersey
SPP	Southwest Power Pool, Inc.
SRMCP	Spinning Reserve Market clearing price
STE	Short-term emergency
TLR	Transmission loading relief
UGI	UGI Utilities, Inc.
VAP	Virginia Electric and Power Company