PJM Interconnection
State of the Market Report
2001

Market Monitoring Unit
PJM Interconnection, L.L.C.
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Contents

STATE OF THE MARKET 2001

Purpose

The *PJM Interconnection State of the Market Report 2001* evaluates the state of the PJM market, identifies specific issues, and recommends potential enhancements to further improve its competitiveness and efficiency.

This report was prepared by the PJM Market Monitoring Unit (MMU) pursuant to Attachment M to the PJM Open Access Transmission Tariff:

> "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."

This report consists of a description of PJM markets, conclusions and recommendations followed by sections covering each of the major market areas in PJM. The report is followed by detailed technical sections describing the competitive dynamics in each of the major market areas and including more detailed analysis and supporting data.

PJM Markets

PJM operates the day-ahead energy market, the real-time energy market, the daily capacity market, the monthly and multi-monthly capacity markets, the regulation market and the monthly FTR auction market. PJM introduced nodal energy pricing with market-clearing prices on April 1, 1998 and nodal, market-clearing prices based on competitive offers on April 1, 1999. PJM implemented a competitive auction-based FTR market on May 1, 1999. Daily capacity markets were introduced on January 1, 1999 and were broadened to include monthly and multi-monthly markets in mid-1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM plans to add a market in spinning reserves in 2002. The markets managed by PJM are the focus of this report.

Conclusions

The MMU concludes that in 2001 the energy markets were reasonably competitive, the capacity markets experienced a significant market power issue in the beginning of the year, the regulation market was competitive and the FTR auction market was competitive and succeeded in its purpose of increasing access to FTRs, although additional action is needed to ensure equal access to FTRs.

The MMU concludes that rule changes implemented by PJM addressed the immediate causes of market power in the capacity market, that the PJM capacity market was reasonably competitive later in 2001, but that market power remains a serious concern given the extreme inelasticity of demand and the high levels of concentration in the capacity credit markets.

The MMU concludes that there are potential threats to competition in the energy, capacity and regulation markets that require ongoing scrutiny and in some cases may require action in order to maintain competition. Under certain conditions, market participants do possess some ability to exercise market power in PJM markets.

Recommendations

The MMU concludes, based on its analysis, that retention of key market rules and certain enhancements to these market rules are required for continued positive results in PJM markets and to continue improvements in the functioning of PJM markets. These include:

1. 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.
2. Modification of the FTR allocation method to eliminate any barriers to retail competition.
3. Development of an approach to identify areas where transmission expansion investments would relieve congestion where that congestion may enhance generator market power and where such investments are needed to support competition.
4. Continued enhancements to the 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.
5. Retention of the $1,000/MWh bid cap in the PJM energy market and investigation of other rules changes to reduce the incentives to exercise market power.
6. Retention of the $100/MW bid cap in the PJM regulation market.

PJM is pursuing actions to address the issues raised in these recommendations. Specifically, PJM:

1. Has taken several steps to encourage demand side price responsiveness in the wholesale markets.
2. Is actively pursuing a change in the FTR allocation method via the stakeholder process.
3. Has begun to address the issue of transmission expansion to relieve congestion to support competition via the stakeholder process.
4. Has modified the capacity market rules to eliminate specific incentives to exercise market power and to make the market term more consistent with the nature of capacity obligations. PJM is also actively engaged in the stakeholder process to review the existing capacity market rules.
5. Has consistently supported the retention of bid caps in markets where they are necessary to limit the exercise of market power.

Based on the experience of the MMU during its third year and its analysis of the PJM markets, the MMU does not recommend any change to the Market Monitoring Unit or the Market Monitoring Plan at this time.

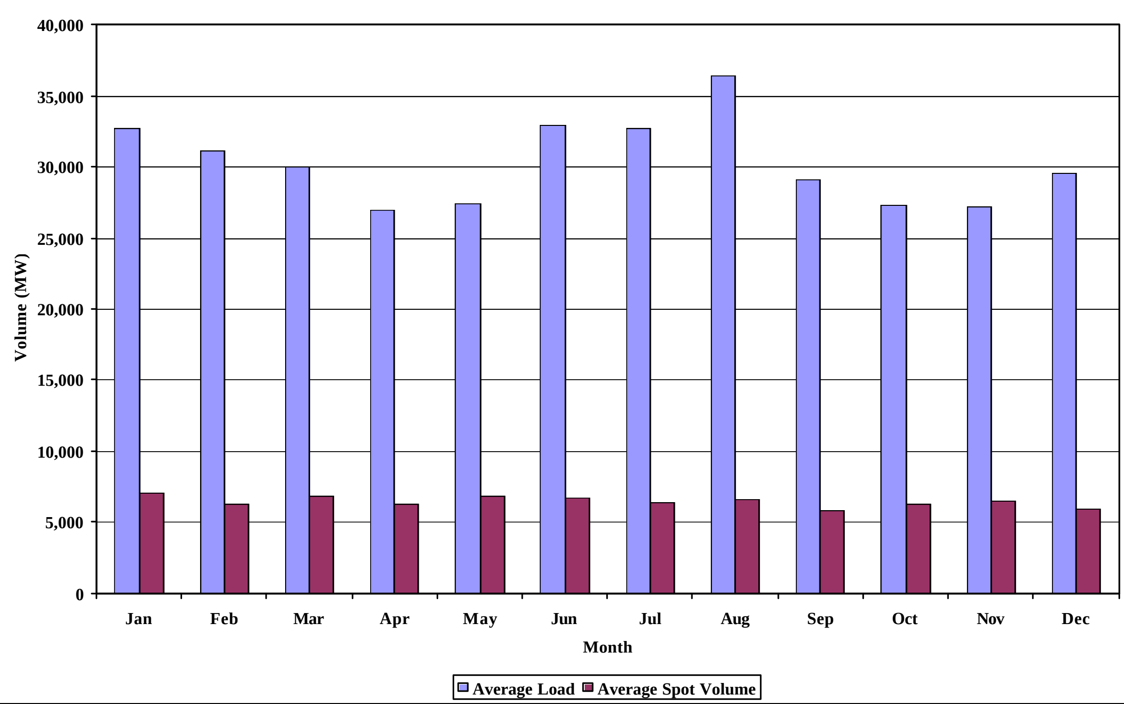
Energy Markets

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, or spot, market. Energy purchases can be made over any time frame from instantaneous real-time balancing market purchases to long term, multi-year bilateral contracts. Purchases may be made from generation located within or outside the PJM control area. Market participants also decide whether and how to sell the output of their generation assets. Generation owners can sell their output within the PJM control area or outside the control area 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 multiple time frames from the real-time spot market to multi-year 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 spot markets, bilateral markets, forward markets, self-supply, imports and exports.

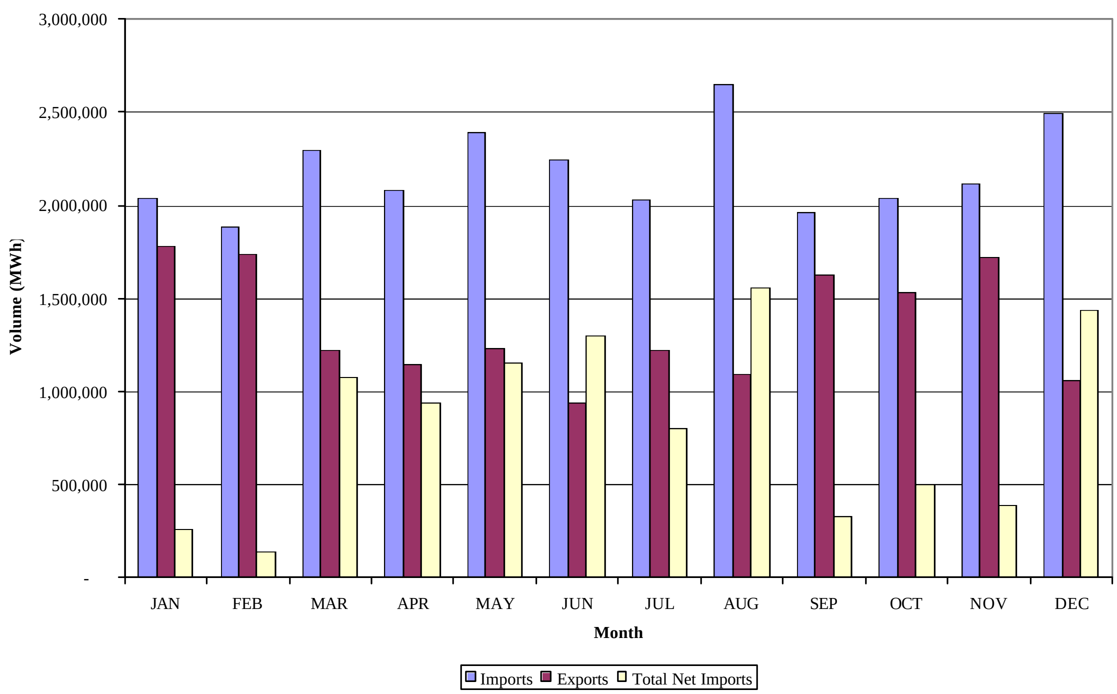
For the full year, real-time spot market activity averaged 6,563 MW during peak periods and 6,395 MW during off peak periods, or 21% of average loads. (Figure 1.) In the day-ahead market, spot market activity averaged 4,794 MW on peak and 4,877 MW off peak, or 15% of average loads. The day-ahead market is a financial market and thus may be used to provide a hedge against price fluctuations in the real-time spot market.

Figure 1: 2001 PJM Average Hourly Load and Spot Market Volume



Market participants can import and export energy in real time in response to price differentials, to fulfill bilateral contracts or to self-supply. PJM was a net importer of energy on a monthly basis for every month in 2001 (Figure 2). On average, PJM imported 1,131 MW in each hour of 2001. Imports and exports respond to market prices. The level of transaction activity illustrates that the PJM energy market exists in the context of a larger energy market. Imports from that larger energy market, in response to PJM prices, served as a source of competition for PJM generation and limited the duration of high prices during 2001 high demand periods.

Figure 2: Total Import and Export Volume - 2001



Energy Market Results

The PJM day-ahead and real-time market prices are key benchmarks against which market participants measure the results of other types of transactions. The MMU has reviewed key measures of market structure and performance for 2001, including net revenue, a price-cost mark up index, concentration levels and prices. In addition, the MMU evaluated the performance and potential of demand side management programs in PJM. Based on that review, the MMU concludes that the energy market was reasonably competitive in 2001.

Net revenue is a significant indicator of overall market performance. Net revenue measures the contribution to capital costs paid by loads and received by generators from energy markets, from capacity markets, from ancillary services and from operating reserve payments. Net revenue is thus an indicator of the profitability of an investment in generation. In 2001, the net revenues from the energy market, the capacity market, ancillary services and operating reserves would have more than covered the fixed costs of peaking units with operating costs of about $45/MWh which ran during all profitable hours. The operating cost of $45/MWh reflects operating cost estimates based on the average cost of gas in 2001 and the heat rate for a peaking unit. The market results in 2001 suggest that the fixed costs of a marginal unit were more than fully covered by net revenues, recognizing that the estimate of net revenues is an upper bound. While market results vary from year to year, the results in 2001 reflect both higher energy prices than in 2000 and higher capacity market prices that resulted in significant part from the exercise of market power during the first quarter of 2001. The net revenue result is consistent with the conclusion that the energy market was reasonably competitive in 2001.

The price-cost markup is a widely used measure of market power. While there are several approaches to this measure, the price-cost markup is defined here as the difference between price and marginal cost, divided by price. Overall, the data on the price-cost markup are consistent with the conclusion that the energy market was reasonably competitive in 2001.

Concentration ratios are a summary measure of market shares, a key element of market structure. High concentration ratios mean that a small number of sellers dominate the market while low concentration ratios mean that a larger number of sellers share in market sales more equally. Concentration measures must be used 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 geographical market areas. However, high aggregate market concentration ratios do indicate an increased potential for market participants to exercise market power. The structural analysis indicates that overall the PJM energy market exhibits moderate market concentration. However, specific geographical areas of the PJM system exhibit moderate to high market concentration that may be problematic when transmission constraints exist. There is no evidence that market power was exercised in these areas in 2001, primarily due to the load obligations of the generators there, but a significant market-power related risk exists going forward should those obligations change. In addition, concentration levels in the intermediate and peaking portions of the PJM supply curve are relatively high.

The result of market structure and the conduct of individual market entities within that structure is reflected in market prices, termed locational marginal prices (LMPs) in PJM. 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. For example, overall average price levels do not reflect congestion, which results in higher prices in some areas and lower prices in other areas.

PJM average prices increased in 2001 over 2000 for several reasons including increased fuel costs and relatively short periods of high load conditions. The simple hourly average system-wide LMP was 15.1% higher in 2001 than in 2000, $32.38/MWh versus $28.14/MWh and 14.3% higher than in 1999. When hourly load levels are reflected, the load-weighted LMP of $36.65/MWh in 2001 was 19.3% higher than in 2000 and 7.6% higher than in 1999. The load-weighted result reflects the fact that market participants typically purchase more energy during high price periods. However, when increased fuel costs are accounted for, the average fuel cost adjusted, load-weighted LMP in 2001 was 7.6% higher than in 2000, $33.05/MWh compared to $30.72/MWh. Thus, after accounting for both the actual pattern of loads and the increased costs of fuel, average prices in PJM were 7.6% higher in 2001 than in 2000.

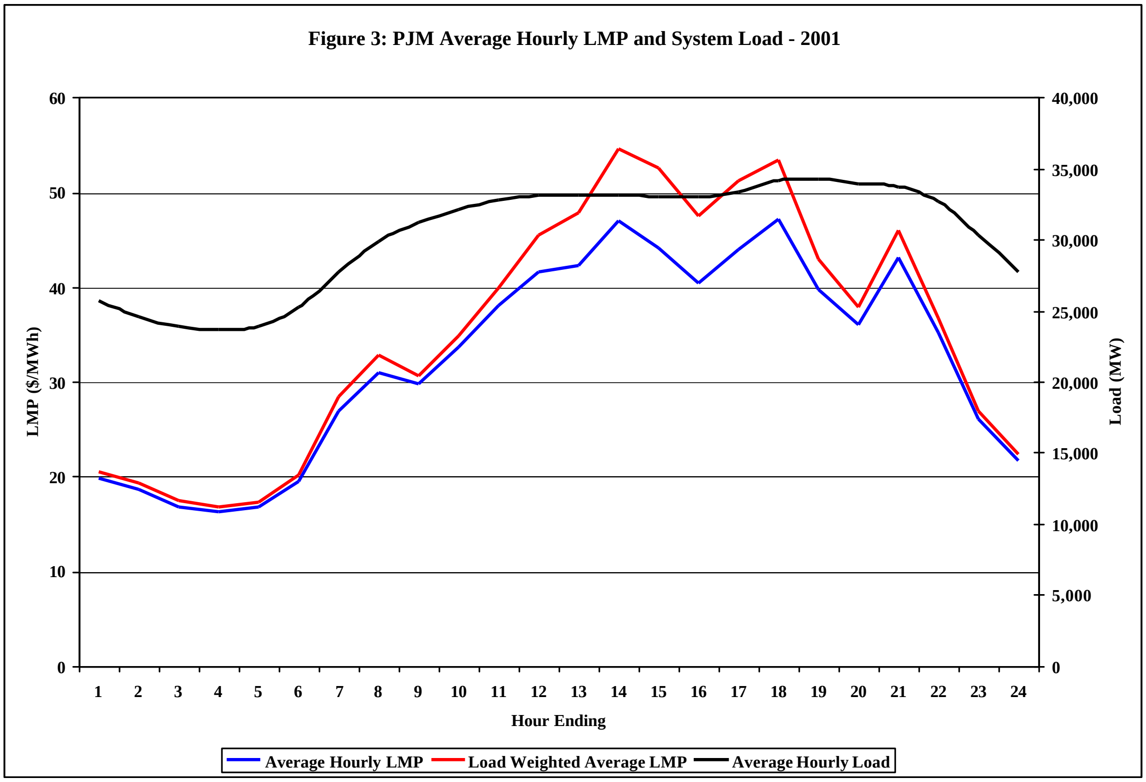
During 2001, PJM average prices exceeded $900/MWH for 10 hours and exceeded $150/MWH for 60 hours. While prices during most hours reflected the interaction of demand and lower-price energy offers, prices on high load days resulted from the interaction of high demands with high price energy offers. These prices reflected a combination of market power and scarcity. If the impact of prices during the high load week of August 6 were excluded, the average load-weighted, fuel cost adjusted price would have been $29.98, a 5.7% decrease from 2000. Energy market price levels are consistent with the conclusion that the energy market was reasonably competitive in 2001.

The energy market results for 2001 were in part the result of periods of hot weather and related demand conditions. Analysis of the energy market has identified a number of concerns regarding competitive conditions including the ability of market participants to exercise market power during periods of high demand, the relatively high levels of concentration during certain periods in markets defined by transmission constraints and the relatively high levels of concentration in the intermediate and peaking portions of the aggregate supply curve.

Energy Market Demand Side

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. 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. In order to develop such demand side response it is necessary to increase the level of load which can see prices in real time, which can react to prices in real time and which can benefit from reacting to prices in real time. This is a complex issue that includes a variety of institutional barriers ranging from jurisdictional issues to fundamental incentive issues. It is difficult to measure the reaction of loads to prices if loads do not have meters that record use by time period. As a result, it is difficult for loads to react to prices in real time and difficult for loads to benefit from reacting to prices in real time. It is not clear what market entity currently has an incentive to invest in the widespread installation of the meters necessary to have effective demand side participation. While retail price caps apparently limit the degree to which price signals from the wholesale market are transmitted to the retail market, retail price caps do not remove the incentive to reduce load at times when wholesale market prices are high. The incentive to reduce load is shifted to the generator or load serving entity which has an obligation to deliver energy to load at a fixed price but which incurs much higher costs to serve that load. These costs include the direct costs incurred by a load serving entity purchasing on the spot market to serve load and the opportunity costs incurred by a generator selling a fixed price product to a load serving entity at times of high spot prices.

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 3) 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.



While PJM's Demand Side Management (DSM) program in 2001 was limited in enrollment, it demonstrated the potential impact of effective demand side participation in the market. The maximum hourly reduction in load that resulted from PJM programs was 1,858 MWh during 2001.[1] The average hourly load reduction during hours when a PJM DSM program was called upon was about 1,200 MW, or about 2.2 percent of peak load. The average price impact of this load reduction was about $135 per MWh. As a measure of the potential of DSM programs to impact price, there would have been a further reduction in price of about $300 per MWh if an additional 2,000 MW of load reductions had been made during the hours when existing programs were activated during the summer of 2001.[2]

Capacity Markets

Capacity Market Design

Under PJM rules, each load-serving entity (LSE) has the obligation to own or acquire capacity resources equal to the peak load that it serves plus a reserve margin. LSEs have the flexibility to acquire capacity by buying or building units, by entering into bilateral arrangements with terms determined by the parties or by participating in the capacity credit markets operated by PJM. Collectively, these arrangements are known as the ICAP market (Installed Capacity Market). The PJM capacity credit markets (CCMs) provide the mechanism to balance the supply of and demand for capacity not met via the bilateral market or via self-supply. Capacity credit markets are intended to provide a transparent, market-based mechanism for new, competitive LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity

1 These load reductions include both the ALM program and the Customer Load Reduction Pilot Program.

2 See: "Report on the 2001-2002 PJM Customer Load Reduction Pilot Program," December 2001.

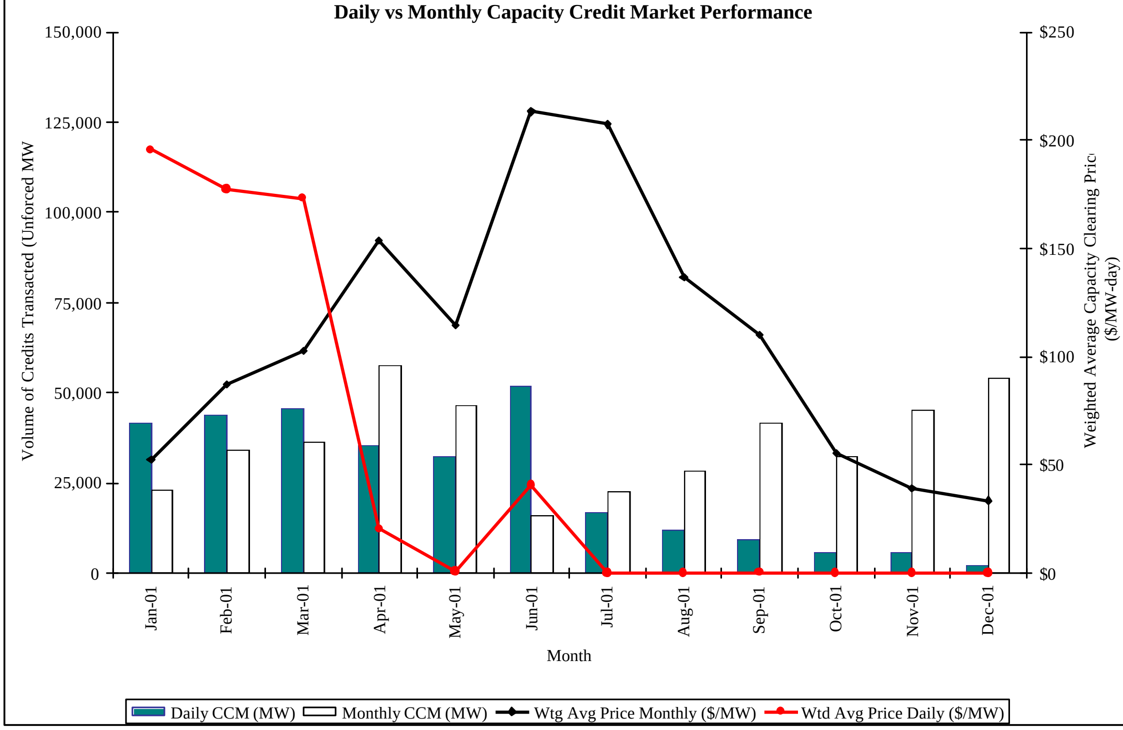
resources when no longer needed to serve load. PJM's daily capacity credit markets enable LSEs to match capacity resources with changing obligations caused by daily shifts in retail load. Monthly, multi-monthly and interval capacity credit markets enable longer-term capacity obligations to be matched with available capacity resources.

Capacity Market Results

The MMU has reviewed the design and structure of the capacity markets, the bidding behavior of market participants and the performance of the capacity markets for 2001. The MMU concludes that there was a significant exercise of market power in the capacity markets in the first quarter of 2001, that the immediate causes of the market power have been successfully addressed by modifications to the rules filed by PJM in the first quarter, but that the potential exercise of market power remains a concern. During 2001, the system of capacity obligations functioned effectively and helped ensure that energy was available during emergency conditions. Nonetheless, given the extreme inelasticity of demand and the high levels of concentration in the capacity credit markets, the potential exercise of market power in the capacity markets requires continued attention. As a result, the MMU recommends that that explicit market power mitigation rules be part of capacity market rules for the future.

The PJM ICAP market plays a critical role in ensuring the reliability of the PJM system by providing a market mechanism to match load obligations of end users in PJM with suppliers of the capacity required to serve those loads reliably. In 2001, 739,262 MW days of capacity were

Figure 4: January Through December 31, 2001
Daily vs Monthly Capacity Credit Market Performance



bought and sold in the capacity markets operated by PJM, a reduction of 29.5 percent from the 1,048,528 MW days transacted in 2000. The overall weighted average price of this capacity was $95.34 per MW-day or $34,894 per MW-year. (Figure 4.) This represents a price increase of

57.9% over 2000. The weighted average annual capacity prices reflect the exercise of market power during the first portion of 2001. Prices returned to more competitive levels in the latter half of 2001.

The State of the Market Reports for 1999 and 2000 recommended modifications to the capacity credit market rules to better align market incentives with PJM's reliability requirements while limiting the exercise of market power. In particular, the reports recommended that the capacity credit market rules should be modified to require that all LSEs meet their obligation to serve load on an annual or semiannual basis and that all capacity resources be offered on a comparable basis. During 2001, PJM filed revised capacity credit market rules that were consistent with these recommendations.

The design of the PJM West capacity market was approved during 2001, with implementation scheduled for 2002. The PJM West capacity market is based on an available capacity design, focused on the short-term deliverability of energy in real time, rather than the installed capacity design used in PJM. The MMU is concerned about the existence of two interacting capacity markets within PJM with different rules and different incentives and the associated potential for gaming. The MMU will carefully monitor these markets as they evolve. The MMU recommends that PJM implement a single capacity market design across all parts of PJM.

Ancillary Services

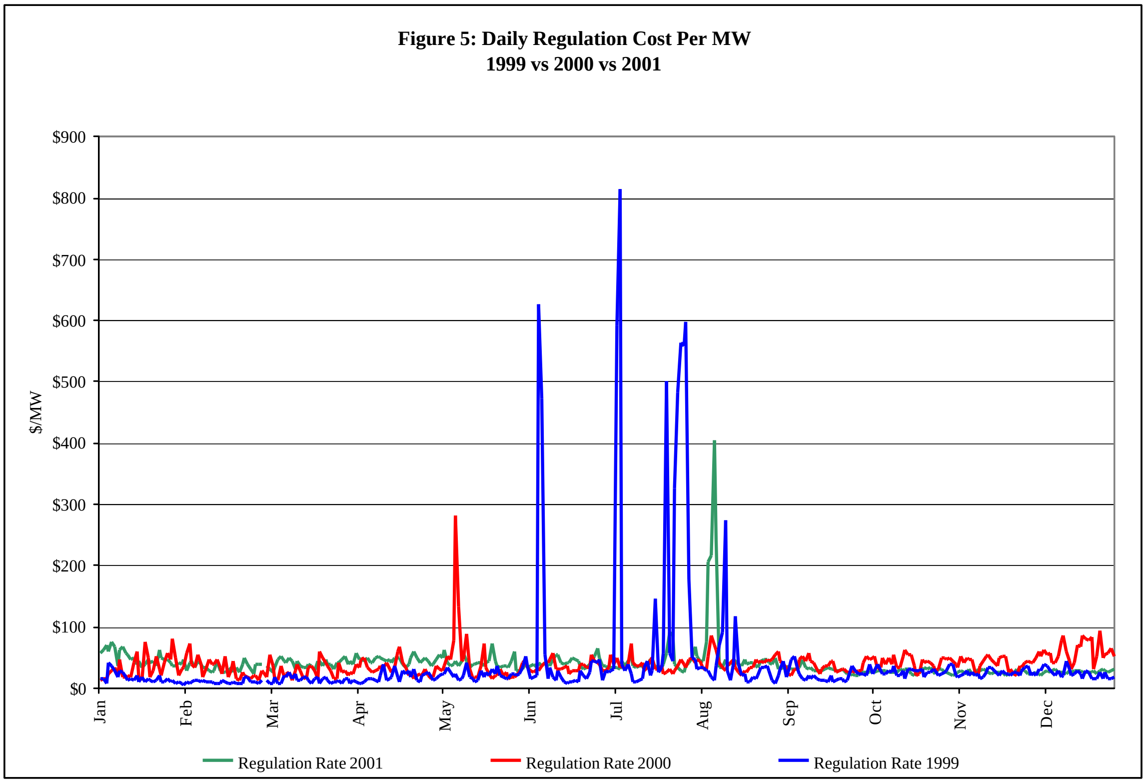
Regulation Market Design

Regulation is one of six ancillary services defined by FERC in Order No. 888. Regulation is required to match generation with short-term increases or decreases in load that would otherwise result in an imbalance between the two. Longer-term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Market participants can acquire regulation in the regulation market in addition to self-scheduling their own resources or purchasing regulation bilaterally.

The market design implemented by PJM provides incentives to owners based on current, unit-specific opportunity costs in addition to the regulation offer price. The market for regulation permits suppliers to make offers of regulation subject to a bid cap of $100 per MW, plus opportunity costs.

Regulation Market Results

The MMU has reviewed the structure of the market, the number and nature of regulation offers, the level of the regulation price and the system regulation performance in 2001. The MMU concludes that the regulation market was competitive in 2001. At present, concerns about the structure of ownership in the regulation market are offset by the available supply of regulation capacity from PJM resources compared to the demand for regulation. The price of regulation under the market introduced on June 1, 2000 has approximately equaled the price under the prior administrative and cost-based system and the market price has exhibited the expected relationship to changes in demand. When energy market demand is high and energy market prices are high, the regulation price is correspondingly high as it includes the opportunity costs associated with not producing energy. (Figure 5.) There is the corresponding potential for non-competitive behavior in the energy market to affect the regulation market. The introduction of a market in regulation resulted in a significant improvement in system regulation performance, measured by the availability of regulation and by NERC Control Performance Standards CPS1 and CPS2.



Spinning Reserve

Spinning reserve is an ancillary service defined as generation synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can be provided by a number of sources including steam units with available ramp (incidental spinning), condensing hydro units, condensing combustion turbines (CTs), CTs running at minimum generation and steam units scheduled day ahead to provide spinning reserves. PJM plans to introduce a market in spinning reserves during 2002.

The total level of required spinning reserves ranged from about 1,100 MW to 1,500 MW from 1999 to 2001 and averaged about 1,200 MW. The costs associated with meeting PJM's demand for spinning reserves declined during 2001 from about $30/MW in January to $17/MW in December. Incidental spinning is not explicitly compensated under current market rules.

Congestion, FTRs and the FTR Auction Market

FTR Auction Market Design

PJM introduced Fixed Transmission Rights (FTRs) in its initial market design in order to provide a hedge against congestion to firm transmission service customers, who pay the costs of the transmission system. PJM introduced the monthly FTR auction market to provide increased access to FTRs and thus increased price certainty for transactions not otherwise hedged by allocated FTRs. The FTR auction provides a mechanism to auction the residual FTR capability on the transmission system and to permit the sale and purchase of existing FTRs.

In PJM, firm point-to-point and network transmission service customers may request FTRs as a hedge against the congestion costs that can result from locational marginal pricing (LMP). An FTR is a financial instrument that entitles the holder to receive revenues (or charges) based on transmission congestion measured as the hourly energy locational marginal price differences in the day-ahead market across a specific path. An FTR does not represent a right to physical delivery of power. FTRs can protect transmission service customers, whose day-ahead energy deliveries are consistent with their FTRs, from uncertain costs caused by transmission congestion in the day-ahead market. Transmission customers are hedged against real-time congestion by matching real-time energy schedules with day-ahead energy schedules. FTRs can also provide a hedge for market participants against the basis risk associated with delivering energy from one bus or aggregate to another. An FTR holder does not need to deliver energy in order to receive congestion credits. FTRs can be purchased with no intent to deliver power on a path.

FTR Auction Market Results

Congestion costs in PJM increased significantly, from $53M in 1999 to $271M in 2001. This increase can be attributed to different patterns of generation, imports and load and, in particular, the increased frequency of congestion at PJM's Western Interface which affects about 75 percent of PJM load. The increased level of congestion suggests the importance of PJM implementing FERC's Order to develop an approach to identify areas where investments in transmission expansion would relieve congestion where that congestion may enhance generator market power and where such investments are needed to support competition.[3]

The FTR Auction Market was designed to make FTRs more widely available to market participants by providing a venue for holders of FTRs to sell them and for PJM to make available unsubscribed FTRs. Since its approval by FERC on April 13, 1999, the basic mechanics of the FTR auction have worked as intended. The FTR auction was competitive in 2001 and has increased access to FTRs. There has been a steady increase in the MW of cleared FTRs. (Figure 6.) The trends in the number of bids, the number of offers and MW of bids have also been upward. The increase in the FTR auction clearing prices reflect the prices bid to purchase FTRs, which were supplied primarily from PJM residual capacity.

Nonetheless, the results of the FTR allocation process and the FTR auction do not yet result in incumbent retail load servers and potential competitors facing the same level of congestion risk for serving the same customers. PJM is currently developing a method for auctioning all FTRs, while continuing to protect the customers who pay for the transmission system from congestion charges, and linking the associated protection from congestion to the end use customers rather than to the incumbent utilities.

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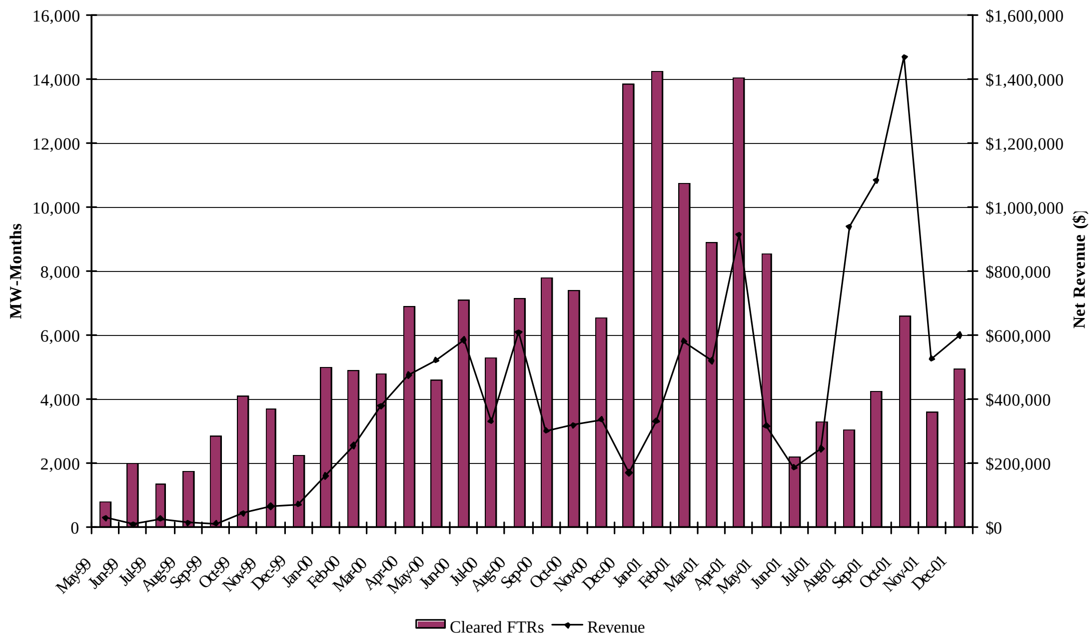
[3] 96 FERC ¶ 61,061 (2001).

Figure 6
FTR Monthly Auction Volume Cleared and Net Revenue



The *PJM Interconnection State of the Market Report 2001* is the fourth annual report on the state of the PJM markets to the Board of Managers of PJM Interconnection, L.L.C. (PJM). This report was prepared by the MMU, fulfilling the commitment described in PJM's Market Monitoring Plan to objectively assess the state of the PJM market and recommend potential enhancements so as to further improve its competitiveness and efficiency.

ENERGY MARKET

Summary and Conclusions

The PJM energy market comprises all types of energy transactions including the sale or purchase of energy in day ahead and real time balancing markets, bilateral and forward markets, and self supply. The energy transactions analyzed in this report include those in the PJM day-ahead and real-time spot markets. These markets provide a key benchmark against which market participants may measure the results of other transaction types. The MMU has analyzed key measures of energy market structure and performance for 2001, including net revenue, price-cost markup, concentration and prices. The MMU concludes that the PJM energy market was reasonably competitive in 2001.

Net revenue is a significant indicator of overall market performance. Net revenue measures the contribution to capital costs paid by loads and received by generators from energy markets, from capacity markets, from ancillary services and from operating reserve payments. Net revenue is thus an indicator of the profitability of an investment in generation. In 2001, the net revenues from the energy market, the capacity market, ancillary services and operating reserves would have more than covered the fixed costs of a peaking unit with operating costs of about $45/MWh which ran during all profitable hours, recognizing that the estimate of net revenues is an upper bound. The operating cost of $45/MWh reflects operating cost estimates based on the average cost of gas in 2001 and the heat rate for a new peaking unit. While market results vary from year to year, the results in 2001 reflect both higher energy prices and higher capacity market prices than in 2000. The higher capacity market prices resulted in significant part from the exercise of market power during the first quarter of 2001.

The price-cost markup is a widely used measure of market power. While there are several approaches to this measure, the price-cost markup is defined here as the difference between price and marginal cost, divided by price. Overall, the data on the price-cost markup are consistent with the conclusion that the energy market was reasonably competitive in 2001 although the evidence is not dispositive. The MMU continues to develop this analysis to refine the measure of the markup over competitive prices and to incorporate explicit accounting for opportunity costs, scarcity rents and economic withholding where appropriate. The increase in the markup index for steam units is a cause for concern, especially given the high levels of concentration in the intermediate segment of the supply curve, as it suggests the potential exercise of market power by mid-merit steam units during times of moderate demand.

Concentration ratios are a summary measure of market shares, a key element of market structure. High concentration ratios mean that a small number of sellers dominate the market while low concentration ratios mean that a larger number of sellers share in market sales more equally. The structural analysis indicates that the PJM control area exhibits moderate market concentration overall, but that concentration in the intermediate and peaking segments of the supply curve is high. In addition, specific areas of the PJM system exhibit moderate to high market concentration that may be problematic when transmission constraints exist. There is no evidence that market power was exercised in these areas during 2001, primarily because of the load obligations of the generators in the areas, but a significant market-power related risk will continue should those obligations change.

The result of market structure and the conduct of individual market entities within that structure is reflected in market prices, termed locational marginal prices (LMPs) in PJM. 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. For example, overall average price levels subsume congestion as well as price differences over time.

PJM average prices increased in 2001 over 2000 for several reasons including increased fuel costs and relatively short periods of high load conditions. The simple hourly average system-wide LMP was 15.1% higher in 2001 than in 2000, $32.38/MWh versus $28.14/MWh and 14.3% higher than in 1999. When hourly load levels are reflected, the load-weighted LMP of $36.65/MWh in 2001 was 19.3% higher than in 2000 and 7.6% higher than in 1999. The load-weighted result reflects the fact that market participants typically purchase more energy during high price periods. However, when increased fuel costs are accounted for, the average fuel cost adjusted, load-weighted LMP in 2001 was 7.6% higher than in 2000, $33.05/MWh compared to $30.72/MWh. Thus, after accounting for both the actual pattern of loads and the increased costs of fuel, average prices in PJM were 7.6% higher in 2001 than in 2000.

During 2001, PJM average prices exceeded $900/MWH for 10 hours and exceeded $150/MWH for 60 hours. While prices during most hours reflected the interaction of demand and lower-price energy offers, prices on high load days resulted from the interaction of high demands with high price energy offers. These prices reflected a combination of market power and scarcity rents. If the impact of prices during the high load week of August 6 were excluded, the average load-weighted, fuel cost adjusted price would have been $29.98, a 5.7% decrease from 2000.

The energy market results for 2001 were in part the result of periods of hot weather and related demand conditions. Analysis of the energy market has identified a number of concerns regarding competitive conditions including the ability of market participants to exercise market power during periods of high demand, the relatively high levels of concentration during certain periods in markets defined by transmission constraints and the relatively high levels of concentration in the intermediate and peaking portions of the aggregate supply curve.

Net Revenue

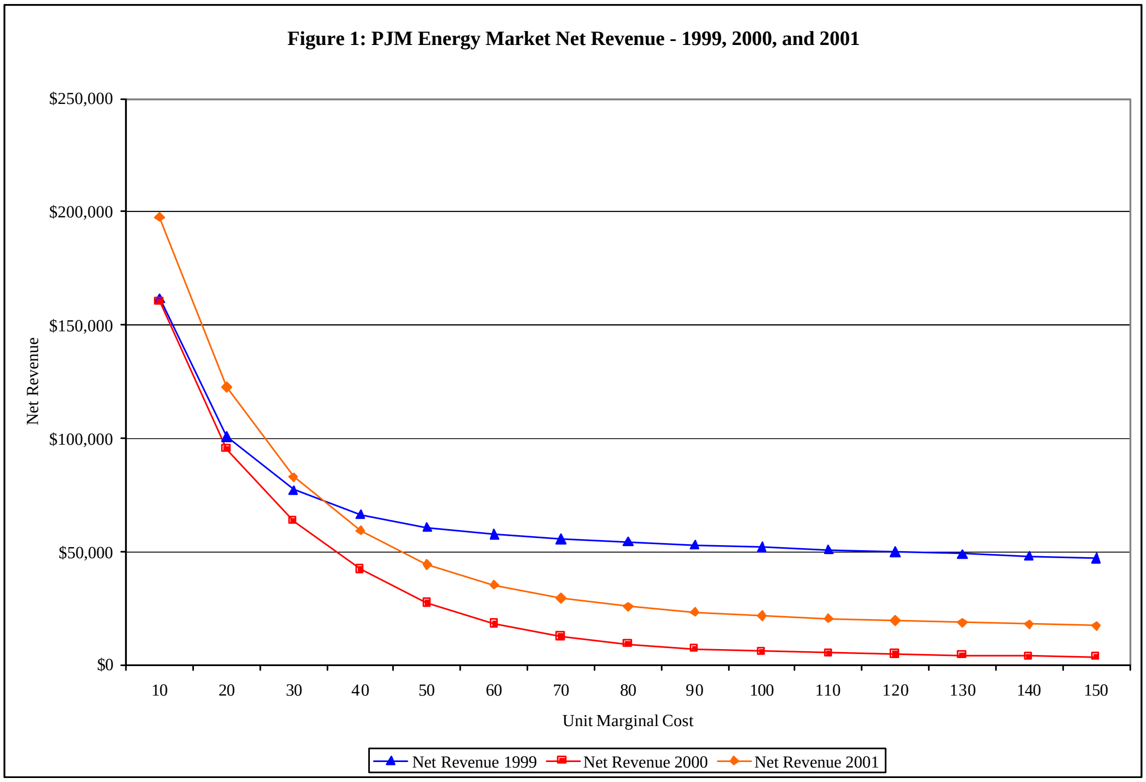
Net revenue is a significant indicator of overall market performance. Net revenue measures the contribution to capital costs paid by loads and received by generators from PJM markets and is thus an indicator of the relative profitability of an investment in generation as well as a measure of the incentives to build new generation to serve PJM markets. The product of energy market prices and output determine gross revenue to generators. Gross revenue less variable cost equals net revenue, and a net revenue curve (Figure 1) illustrates the relationship between net energy revenue and generation cost. Net revenue represents revenue after variable costs, fuel and variable operation and maintenance (O&M) expenses, are covered. Net revenue is available to cover fixed costs, including a return on investment, depreciation and fixed O&M expenses.

In a perfectly competitive, energy-only market, net revenue would be expected to equal the total of all these fixed costs for the marginal unit, including a competitive return on investment, in long run equilibrium. The PJM capacity, energy and ancillary services markets are all sources of revenue to cover the fixed costs of generators. In a perfectly competitive market, with energy, capacity and ancillary services payments, the net revenue from all sources would equal the fixed costs of generation, for the marginal unit, in long run equilibrium. In other words, net revenue is a measure of whether generators are receiving competitive returns on invested capital and whether market prices are high enough to encourage the entry of new capacity. The net revenue curves presented here reflect net revenues from energy markets only, while the additional sources of revenue are shown in Table 1.

Figure 1, PJM Energy Market Net Revenue, shows, on its vertical axis, the dollars per MW-year received by a unit in PJM which operated whenever the system price exceeded the variable cost levels ($/MWh) on the horizontal axis. For example, a unit with marginal costs equal to $30/MWh had an incentive to operate whenever the LMP exceeded $30/MWh. If this unit operated in all profitable hours, whenever LMP exceeded $30/MWh, it would have received about $83,000/MW in net revenue during 2001 from the energy market. The net revenue curve is an approximate measure of the contribution to generators' fixed costs from the energy market and represents the upper bound of such contributions. The net revenue curve does not take account of forced outages or operating constraints. For example, a twelve hour start up time could prevent a unit from running during two profitable hours in the morning and two profitable hours in the evening, separated by eight non-profitable hours. 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.

Energy market net revenues in 2001 exhibited a different shape than in 1999. In 1999, if a unit with marginal costs of $30/MWh operated in all hours when the LMP exceeded $30/MWh, it would have received about $77,000/MW in net energy revenue versus about $64,000 in 2000 and about $83,000 in 2001. The relationship between energy market net revenues in 2000 and 2001 remains approximately constant while it reverses for energy market net revenues in 1999 and 2001. As the marginal cost increases, net revenues in 1999 exceed those in 2001 and the gap widens for higher marginal cost units. In 1999, if a unit with marginal costs of $50/MWh operated in all hours when LMP exceeded $50/MWh, it would have received about $61,000/MW in net energy revenue versus about $27,000 in 2000 and about $44,000 in 2001.

The differences in the shape and position of the net energy revenue curves for the three years result from the different distribution of energy market prices. These differences illustrate the significance of a relatively small number of high price hours to the profitability of high marginal cost units. While 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 hours except hours 1200 through 1800, when 1999 prices significantly exceeded 2000 prices. These peak hours included the hours when 1999 prices spiked to in excess of $900 for a limited number of hours. The 91 hours in 1999 when prices exceeded $150/MWh and the 43 hours in which price exceeded $800 generally occurred during these peak hours and resulted in the shape of the net revenue curve for 1999. In 2000, there were only 27 hours in which the price exceeded $150 and only 1 hour in which the price exceeded $800. The limited number of high price hours in 2000 resulted in lower net revenue for units operating at marginal costs in excess of $30/MWh.



Average prices in 2001 exceeded those in both 2000 and 1999 which explains why the net revenue curve for 2001 is higher for marginal cost levels less than about $35/MWh. While average prices were higher in 2001 than 1999, the price spikes in 2001 were more limited in frequency and duration than in 1999 which explains why the net revenue curve for 2001 is below that for 1999 for marginal costs in excess of $35/MWh.

Generators receive capacity related revenues in addition to energy related revenues. In 2001, PJM capacity resources received a weighted average payment from all capacity markets of $95.34/MW-day, or $36,700/MW for the year. In 2000, the average payment from the capacity markets was $60.55/MW-day, or $23,308/MW-year, while in 1999 the average payment from the capacity markets was $52.86/MW-day, or $20,469/MW-year.[1] The higher capacity market revenues in 2001 offset the positive differential in net energy revenue between 1999 and 2001, for units with marginal costs in excess of $35/MWh, while capacity market revenues increased the differential between 2001 and 2000. Thus, a PJM capacity resource with a marginal cost of $30/MWh which operated in all profitable hours would have received revenues of about $120,000/MW-year in 2001 from capacity and energy markets versus about $98,000/MW-year in 1999 and about $87,000/MW-year in 2000.

Generators received ancillary service revenues and operating reserve revenues in addition to energy and capacity related revenues. Aggregate ancillary services revenues from regulation were about $131,000,000 and from spinning about $35,000,000 or a total of $166,000,000 in 2001. Spread over all installed capacity, this is about $2,900 per MW-year. Total operating

[1] These values are on an installed basis while the capacity prices are on an unforced basis.

reserve payments were about $249,000,000 in 2001. When operating reserve payments are spread over total installed capacity this is about $4,300 per MW-year.

Taking account of all the revenue streams to generation, a PJM capacity resource with a marginal cost of $30/MWh would have received revenues of about $127,000/MW-year in 2001 while a unit with a cost of $50/MWh would have received revenues of about $88,000/MW-year. Table 1 presents the results for units with a range of marginal costs. The differential in net revenues for a unit with a marginal cost of $50/MWh between 2001 and 2000 was about $31,500. This differential results from the $17,000 difference in energy market revenues and $13,400 difference in capacity market revenues, with the balance made of up of differences in ancillary services and operating reserve revenues. The net revenues for a unit with a marginal cost of $50/MWh was basically equal for 2001 and 1999. The composition of net revenues was quite different in each year, with energy market revenues in 1999 exceeding those in 2001 by about $16,000 and capacity market revenues in 2001 exceeding those in 1999 by about $16,000.

To put the net revenue results in perspective, the average gas cost in PJM in 2001 was about $4.60/MMBtu and the corresponding variable cost for a new combustion turbine (CT) was between $45 and $50/MWh. The corresponding variable cost for a combined cycle (CC) was between $30/MWh and $35/MWh.[2] The PJM Capacity Deficiency Rate (CDR) is $58,400/MW-year. The CDR is 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/MW-year designed to reflect the difference between the PJM dispatch rate and CT costs during the hours when the CTs ran. Thus the annual fixed cost of a CT in PJM, per the CDR calculations, is about $63,000/MW-year. The capacity costs of intermediate and base load units are higher while their variable costs are lower than those of a CT.

In 2001, the net revenues from the energy market, the capacity market, ancillary services and operating reserves of between $103,064 and $88,212 would have more than covered the fixed costs of peaking units with operating costs between $40 and $50/MWh which ran during all profitable hours.

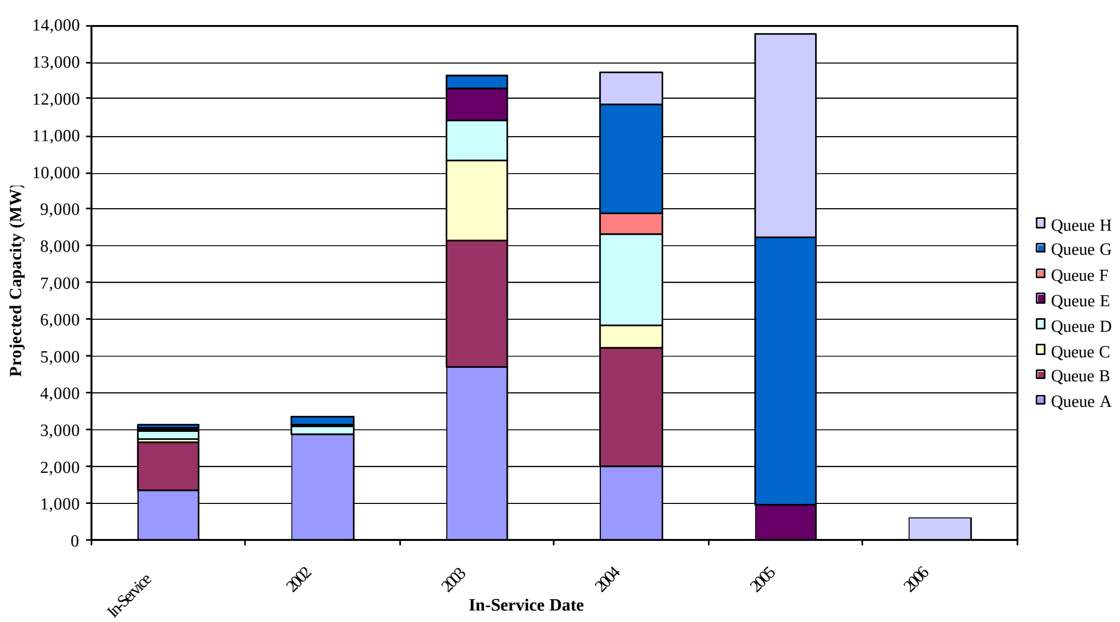
While it can be expected that in the long run, in a competitive market, net revenues from all sources will cover the fixed costs of investing in new generating resources including a return on investment, actual results will vary from year to year. Revenues from the capacity market, ancillary services and operating reserves clearly vary from unit to unit depending on particular capacity market transactions, the provision of specific ancillary services and the receipt of specific operating reserves. The results in 2001 suggest that the fixed costs of a marginal unit were more than fully covered, even given that the estimate of net revenues is an upper bound and that the fixed cost estimate based on the CDR may be somewhat low. The data suggest that generators' net revenues exceeded the fixed costs of generation and that this was primarily the result of the high capacity market prices that resulted from the exercise of market power in PJM capacity credit markets in 2001.

[2] The two key variables are the cost of fuel and the heat rate of the unit.

Table 1: Net Revenues in 2001 by Marginal Cost of Unit					
	Net Revenue Sources ($/MW-year)				
Unit Marginal Cost	Energy	Capacity	Ancillary Services	Operating Reserves	Total
($/MWh)					
$10	$197,632	$36,700	$2,851	$4,275	$241,458
$20	$122,746	$36,700	$2,851	$4,275	$166,572
$30	$82,833	$36,700	$2,851	$4,275	$126,659
$40	$59,238	$36,700	$2,851	$4,275	$103,064
$50	$44,386	$36,700	$2,851	$4,275	$88,212
$60	$35,223	$36,700	$2,851	$4,275	$79,049
$80	$25,753	$36,700	$2,851	$4,275	$69,579
$100	$21,652	$36,700	$2,851	$4,275	$65,478
$120	$19,498	$36,700	$2,851	$4,275	$63,324
$140	$17,968	$36,700	$2,851	$4,275	$61,794

Net revenues provide an incentive to build new generation to serve PJM markets. While these incentives operate with a significant lag and are based on expectations of future net revenues, the level of planned new generation in the PJM area reflects the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary services markets plus operating reserve payments. At the end of 2001, about 46,000 MW of capacity are in the

Figure 2: PJM Control Area Queued Capacity



Project in-service dates are provided by the generation developers.

generation request queues for construction through 2007, compared to installed capacity of about 59,000 MW. (Figure 2.) While it is clear that not all of this generation will be completed, PJM is steadily adding capacity.

Price-Cost Markup

The price-cost markup is a widely used 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.

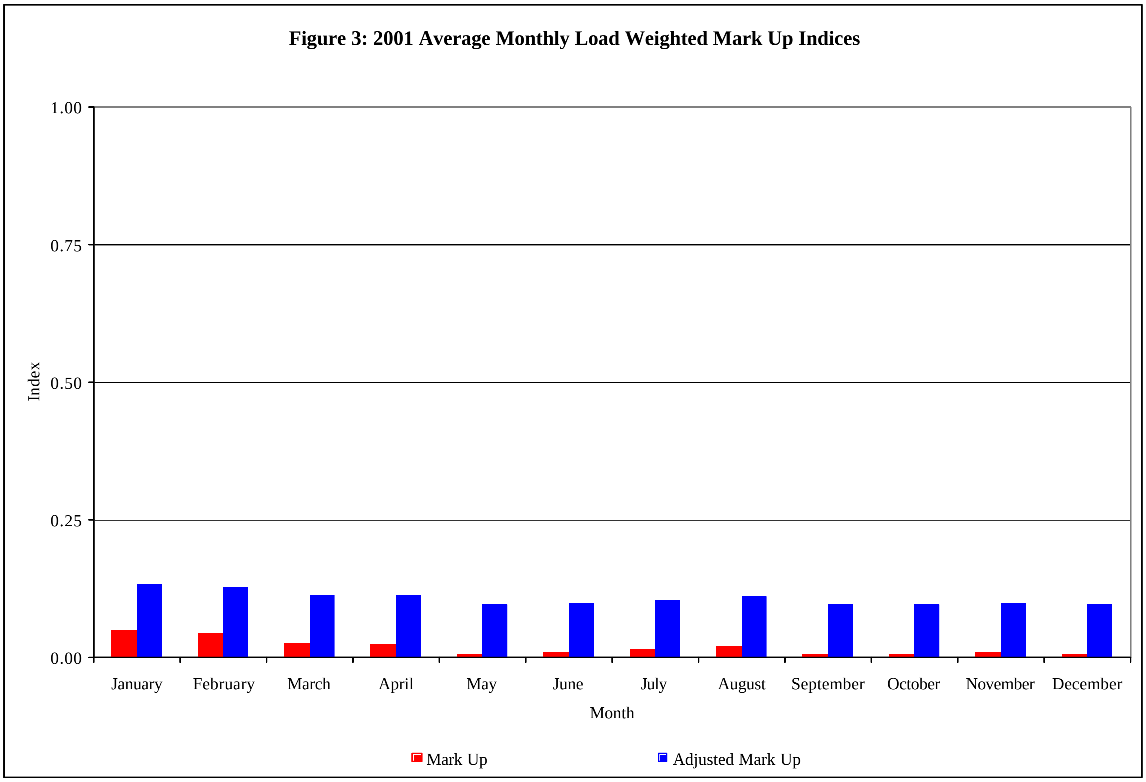
A price-cost markup index can be defined as the difference between price and marginal cost, divided by price, where price is determined by the offer of the marginal unit and marginal cost is from the highest marginal cost unit operating. (The markup index = (P – MC)/P.) This markup index measure varies from 0, when price equals marginal cost and there is no markup, to 1.00 when price is high compared to marginal cost.[3] (See Figure 3.)

PJM has data on the price and cost offers for every unit in the PJM system for which construction commenced prior to July 9, 1996. The markup can thus be calculated directly for any time period. The markup 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 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.[4] The resultant markups are adjusted so that the mark up 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 3 shows the monthly average of the markup index. The average markup was .02 in 2001, with a maximum mark up of .05 in January and a minimum markup of less than .01 in November. Generators in PJM are permitted to provide cost-based offers that include a markup over marginal cost of 10 percent. Since an unknown number of generators have increased their cost bids by 10 percent, the calculated markup could be low. The adjusted markup index in Figure 3 adjusts the markup index results assuming that all units' costs include a 10 percent markup over cost. For the adjusted markup index, the average markup in 2001 was .11 in 2001, with a maximum mark up of .13 in January and a minimum markup in October of .09.

3 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 ten percent. Thus the index can be negative if the marginal unit's offer price was between cost and cost plus ten percent.

4 For example, if a marginal unit with a markup index of .50 set the LMP for 3,000 MW of load in an interval and a second marginal unit with a markup index of .01 set the LMP for 27,000 MW of load, the weighted average markup index for the interval would be .06.



The mark up index calculation is based on the marginal production cost of the highest marginal cost operating unit and does not include the marginal cost of the next most expensive unit, the appropriate scarcity rent, if any, or the opportunity cost, if any, as a component of cost. Thus, if the marginal unit is a combustion turbine (CT) with a price offer equal to $500/MWh and the highest marginal cost of an operating unit is $130/MWh, the observed price-cost markup index would be .74 ((500-130)/500). However, if the unit has the ability to export power and the real-time price in an external control area is $500/MWh, then the appropriately calculated markup would actually be zero.

In order to understand the dynamics underlying the observed markups, the marginal units were analyzed in more detail including fuel type, plant type and ownership.

Figure 4 shows the average unit specific markup by fuel type. The mark up = (P-MC)/P where price and marginal cost are for the specific unit of the identified fuel type, which is marginal during any five-minute interval. Units using coal and miscellaneous fuels showed the highest levels of markup index. Coal and miscellaneous fuel units had average markups of between .10 and .09 during 2001.[5]

[5] The primary fuel types included in the miscellaneous category include methane, petroleum coke, refuse, refinery gas, waste coal, wood and wood waste.

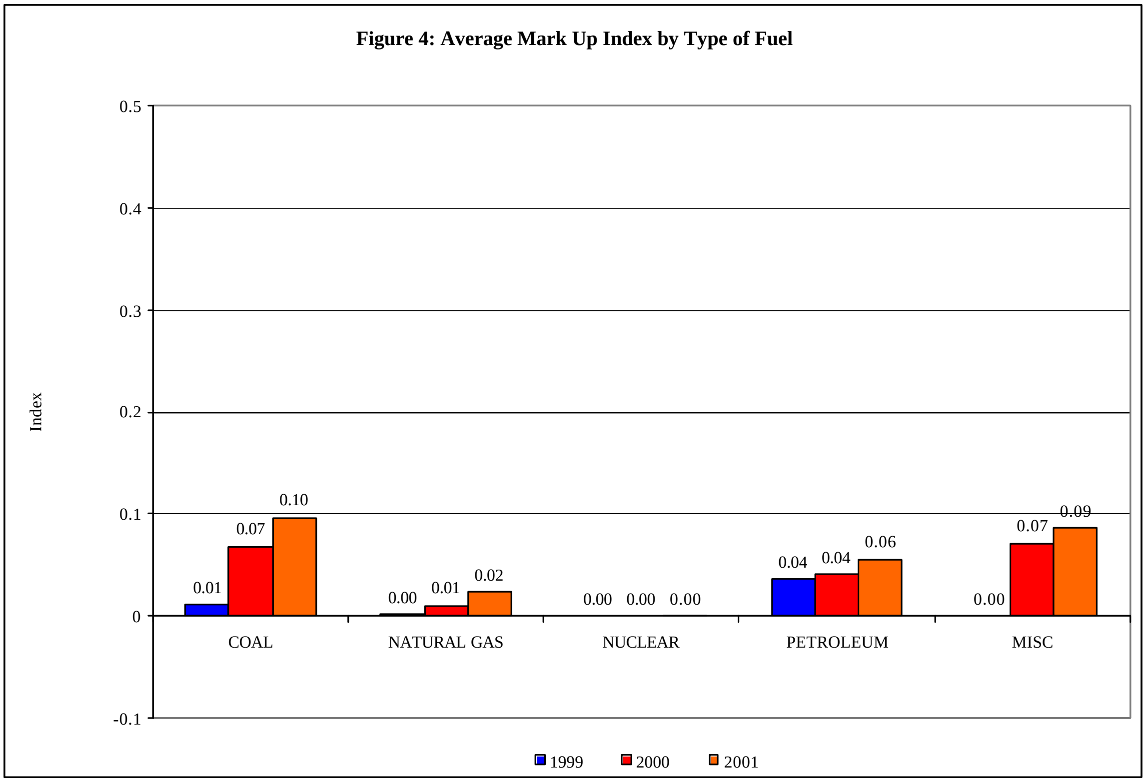


Figure 5 shows the type of fuel used by the marginal units. In 2001, coal-fired units were on the margin 49% of the time, petroleum-fired units 32% of the time, gas-fired units 18% of the time and nuclear units 1%. Petroleum-fired units' share of marginal usage increased from 31% in 2000 to 32% in 2001, the share of coal also increased by about 1%, the shares of nuclear and miscellaneous decreased and the share of natural gas was unchanged.

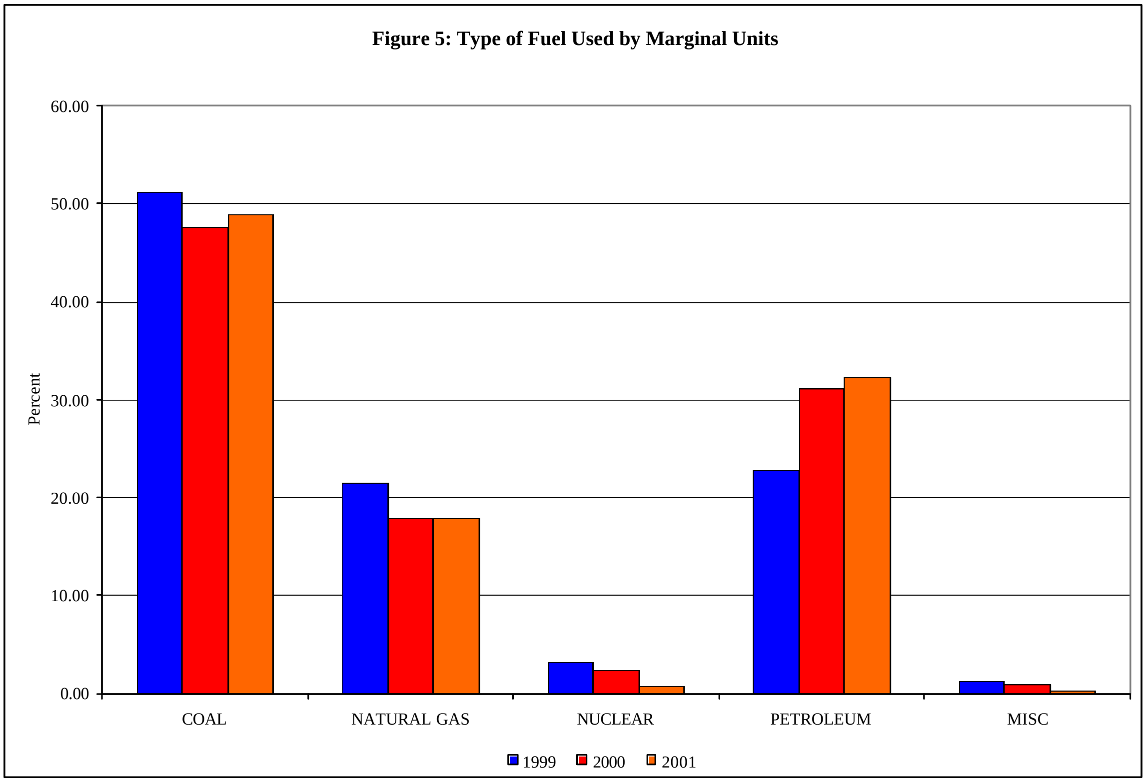
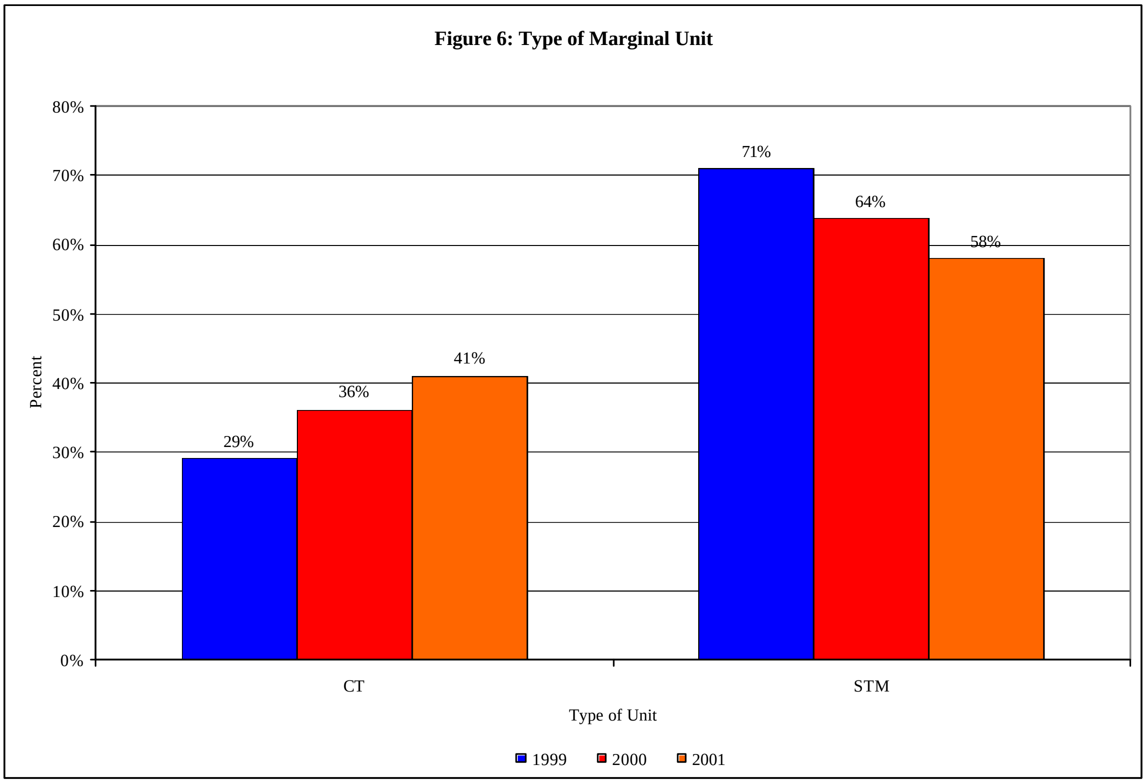


Figure 6 shows the type of units on the margin during 2001, 2000 and 1999. CTs were the marginal unit 29% of the time in 1999, 36% of the time in 2000 and 41% of the time in 2001.



Steam units were the marginal unit 71% of the time in 1999, 64% of the time in 2000 and 58% of the time in 2001.

Figure 7 shows the average markup index by type of unit. The average annual mark up index was higher for steam units than for CTs, and the average annual index increased for both steam units and CTs in 2001.

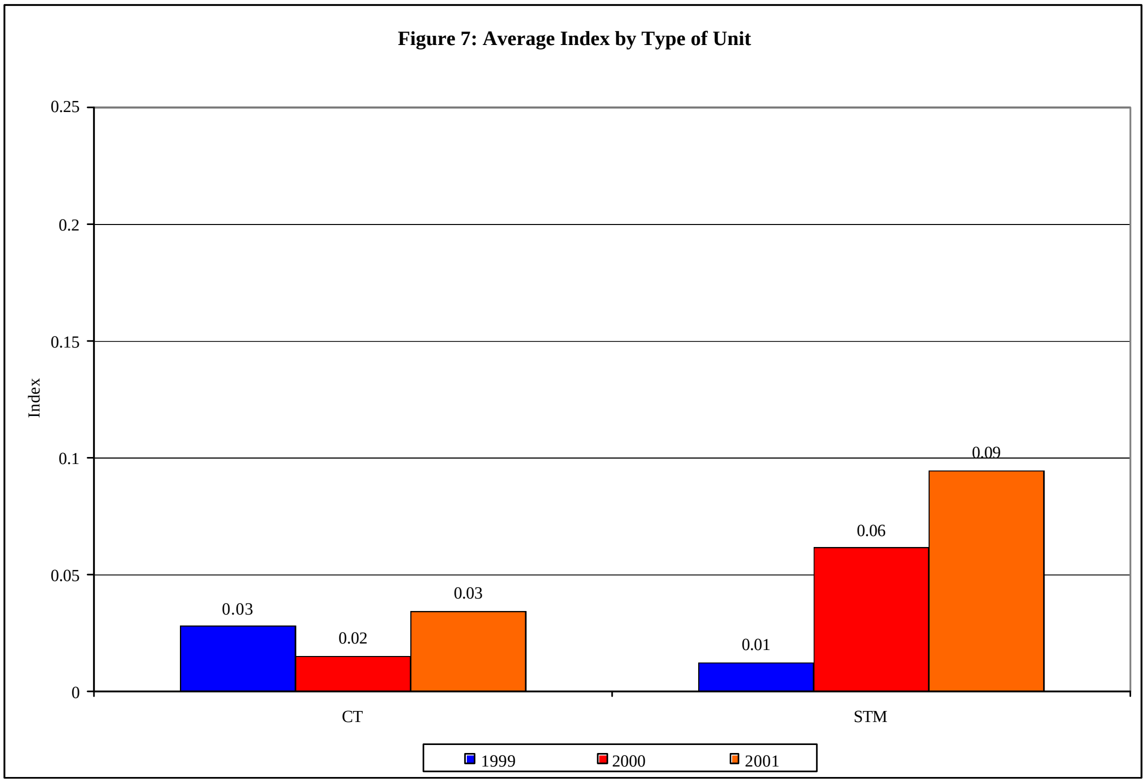
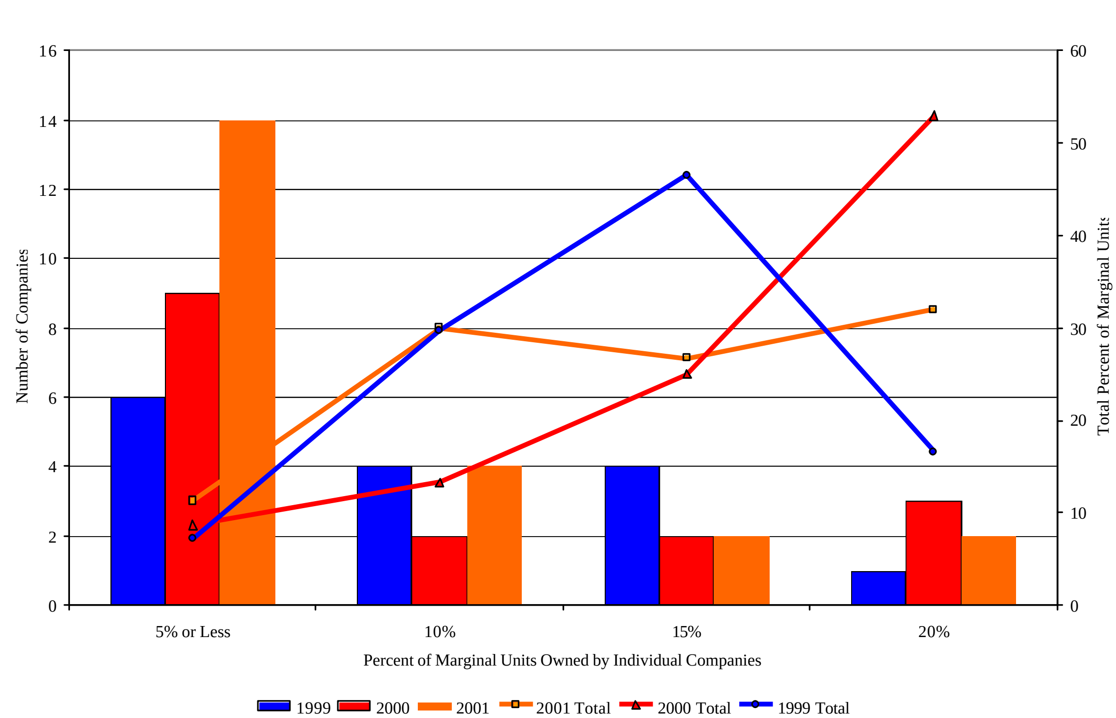


Figure 8 shows the distribution of ownership of the marginal units. Taking all the units which were on the margin for one or more five-minute intervals during the year, in 2001, the bars on the graph show that two companies each owned 15-20% of the marginal units while two other companies each owned 10-15% of the marginal units. The “2001 Total” line on the graph shows that two companies owned the marginal unit in more than 30 percent of the five minute intervals in 2001, while four companies owned the marginal unit in about 60 percent of the intervals in 2001, and eight companies owned the marginal unit in almost 90 percent of the intervals. In 2000, almost 80% of the marginal units were owned by the top five companies while in 1999, more than 60% of the marginal units were owned by the top five companies. When combined with the information on bidding behavior, the distribution of ownership of marginal units is a further cause for concern.

Figure 8: Marginal Unit Ownership



Overall, the index results presented here are consistent with the conclusion that the energy market was reasonably competitive in 2001. The MMU will continue to develop this analysis to refine the measure of the markup over competitive prices and to incorporate explicit accounting for opportunity costs and scarcity rents.

Market Structure

Concentration ratios are a summary measure of market shares, a key element of market structure. High concentration ratios mean that a small number of sellers dominate the market while low concentration ratios mean that a larger number of sellers share in market sales more equally. Concentration measures must be used carefully in assessing the competitiveness of markets. The best tests for assessing the competitiveness of markets are direct tests of the conduct and performance of individual participants within markets and their impact on market prices. The price-cost markup test is one such test and direct examination of the offer behavior of individual market participants is another. Low aggregate- market concentration ratios do not establish that a market is competitive or that market participants cannot exercise market power. However, high market concentration ratios do indicate an increased potential for market participants to exercise market power. Concentration ratios are presented here because they provide useful information on market structure and are a widely used measure of market structure.

The analysis indicates that the PJM Control Area exhibits moderate energy market concentration overall, but that concentration in the intermediate and peaking segments of the supply curve is high. High levels of concentration, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. In addition, specific areas of the PJM system exhibit moderate to high market concentration that may be problematic when transmission constraints exist. There is no evidence that market power was exercised in these areas in 2001, primarily due to the load obligations of the generators in those areas, but a significant market-power related risk exists going forward should those load obligations change.

Method

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated as the sum of the squares of the market shares of the firms in a market. Hourly energy market HHIs were calculated based on the real-time energy output of generators located in the PJM control area, adjusted for hourly imports (Table 2). The installed HHIs were calculated based on the installed capacity of PJM generating resources, adjusted for aggregate import capability (Table 3). The ability of the transmission system to deliver external energy into the control area was incorporated in the HHI calculations because additional energy can be imported into PJM under most conditions. The overall maximum hourly HHI was calculated by assigning all actual positive net tie flows in each hour to the market participant with the largest market share, while the overall minimum hourly HHI was determined by assigning hourly net tie flows to five non-affiliated market participants. The overall maximum installed HHI was calculated by assigning all import capability to the market participant with the largest market share, the overall minimum installed HHI was determined by assigning import capability to five non-affiliated 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, parent organization. Hourly and installed HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. The hourly segment HHIs were calculated based on hourly market shares, unadjusted for imports, while the installed segment HHIs were calculated on an installed capacity basis, also unadjusted for import capability.

In addition to the aggregate PJM calculations, HHIs were calculated for various 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 the existence of transmission constraints.

FERC's Merger Policy Statement states that a market can be broadly characterized as unconcentrated when the market HHI is below 1000 (the equivalent of 10 firms with equal market shares), as moderately concentrated when the market HHI is between 1000 and 1800 and highly concentrated when the market HHI is greater than 1800 (the equivalent of between 5 and 6 firms with equal market shares).[6]

Results

The results of the aggregate PJM HHI calculations for both the installed and the hourly measure (Tables 2 and 3) indicate that the PJM energy market is, in general, moderately concentrated by the FERC standards. Overall market concentration varies from 975 to 2140 based on the hourly measure and from 1155 to 1405 based on the installed measure.[7]

Table 2. 2001 PJM Hourly HHIs

	Overall Minimum	Overall Maximum
Maximum	1885	2140
Average	1375	1565
Minimum	975	1275

Table 3. 2001 PJM Installed HHIs

	Overall Minimum	Overall Average	Overall Maximum
Overall	1155	1280	1405

Tables 4 and 5 include HHI values for the capacity and energy measures by supply curve segment, including base load, intermediate and peaking plants. The hourly measure indicates that intermediate and peaking segments are highly concentrated on average while the installed measure indicates that all segments are moderately concentrated on average. For both hourly and installed measures, HHIs are calculated for facilities located in PJM only.

Table 4. 2001 PJM Hourly HHIs by Segment

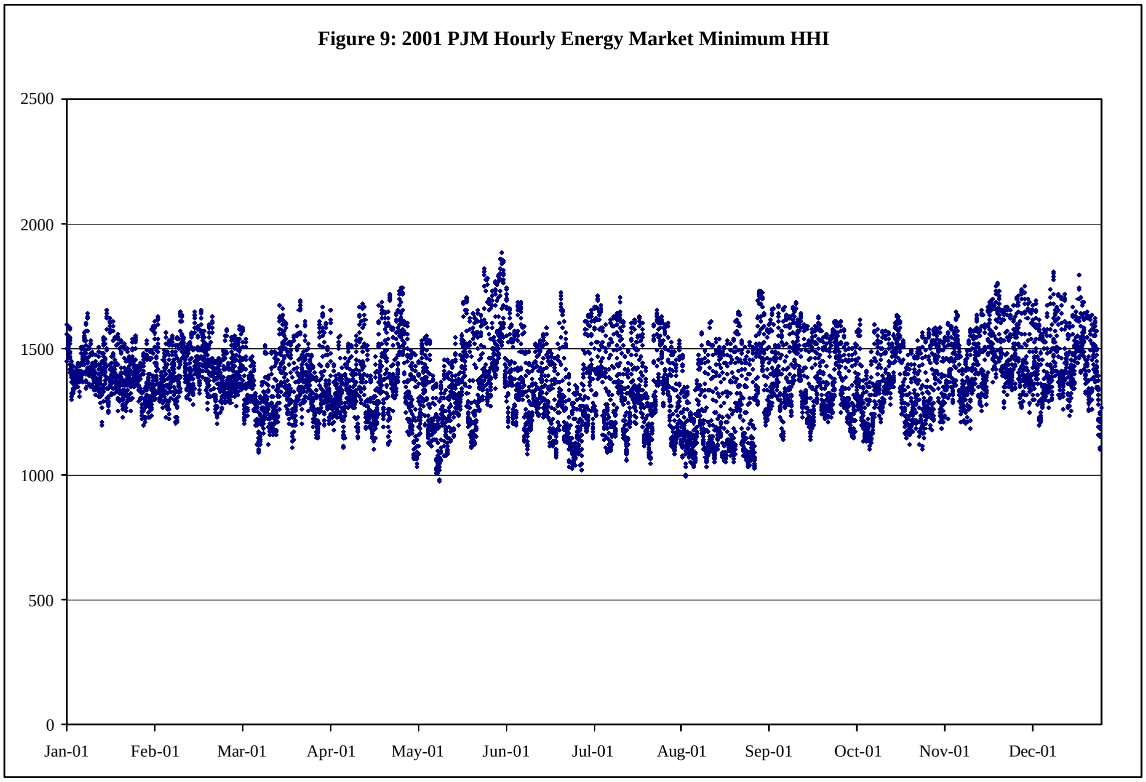
	Base	Intermediate	Peak
Maximum	1725	4575	9080
Average	1525	2925	5140
Minimum	1325	1270	1200

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.

7 The maximum HHI level for the Overall Maximum hourly measure is based on the assumption that all imports are controlled by the market participant with the largest market share. While this is an important sensitivity, there is no evidence that this has occurred or is likely to occur.

Table 5. 2001 PJM Installed HHIs by Segment			
	Base	Intermediate	Peak
HHI	1397	1448	1776

Figure 9 shows the HHI results for the Overall Minimum hourly measure.



High Market Concentration and Frequent Congestion

There were five areas within the PJM Control Area that had high local market concentration and experienced frequent congestion in 2001: Northern Public Service, Northcentral Public Service, Eastern PJM, the Delmarva Peninsula, and the Atlantic subarea of Conectiv.

Northern Public Service was constrained during 602 hours in 2001, compared to 637 hours in 2000. Of the congested hours, 45 percent occurred during on-peak periods. Energy transfers into the area were primarily restricted by limitations on the Roseland-Cedar Grove and Cedar Grove-Clifton corridors. When this area is constrained, some 3,200-4,600 MW of load is isolated, depending on load levels. Market concentration for the local market is high, with a minimum HHI of 4800.

Northcentral Public Service also exhibits relatively high concentration and experienced local congestion during 371 hours in 2001, a decrease of about 100 hours from 2000, with 80 percent of congested hours during on-peak periods. Energy transfers into the area were primarily restricted by limitations on the Brunswick-Edison-Meadow Road 138 kV circuit. When this area is constrained, some 350-550 MW of load is isolated. Market concentration varies from a minimum HHI of 2200 to a maximum HHI of over 9000.

Transfers into PJM East were constrained by the Eastern Interface limit during 230 hours in 2001, a decrease from 345 hours from 2000. Of the congested hours, 80 percent occurred during on-peak periods. This constraint isolates 19-27,000 of eastern load from the rest of PJM. Market concentration was moderate to high with minimum, average, and maximum HHIs of 1695, 2270, and 2845. About 60 percent of the new generation projects in the PJM queues are located in the eastern region of PJM, which, if built, may decrease concentration and could reduce the frequency of congestion.

Transmission reinforcements[8] appear to have alleviated a major constraint that frequently affected the entire Delmarva Peninsula. Prior to 2001, the DPL South voltage limit had frequently isolated some 1,100-1,850 MW of load on the peninsula. This constraint, which was in effect during 229 hours in 2000, was not encountered at all during 2001. However, many local constraints that typically isolate small, highly concentrated load pockets still exist and are frequently encountered. Such local constraints occurred during more than 3,000 hours in 2000 and nearly 2,000 hours in 2001, with 85% of congested hours occurring during on-peak periods. The HHIs in these areas ranged from 3500 to 10000. Twelve 69 kV and six 138 kV constraints were encountered on the Peninsula during 2001.

The Atlantic Electric area also had many local constraints that typically isolated small, highly concentrated load pockets of 100 MW or less. Such constraints were in effect for 1,600 hours during 2001, an 1,100-hour increase over 2000, with 65 percent of the constraints occurring during on-peak periods. Two 69 kV constraints accounted for 55 percent of the congested hours: Motts Farm-Cedar and Shield Alloy-Vineland. The HHIs in these load pockets were high, ranging from 3500 to 10000.

[8] DPL transmission reinforcements:

- Added 515 MVAR of capacitors (218 MVAR transmission, 297 MVAR distribution).
- Added 300 MVAR of SVCs (150 MVAR at Indian River 230, 150 MVAR at Nelson 138).
- Added a second Steele 230/138 transformer (increased capability by 289 MW).
- Replaced Vienna 230/138 transformer (increased capability by 284 MW).
- Converted Loretto-Oak Hall 69 kV to 138 kV (increased capability by 125 MW).
- Added a second Oak Hall 138/69 transformer (increased capability by 134 MW).
- Added a New Church 138 kV substation.
- Added a second New Church-Oak Hall 138 kV (increased capability by 342 MW).

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. The remainder of this section discusses PJM energy market prices. The Appendix provides methodological background and additional, more detailed, price data and comparisons.

Prices in the Real-Time Spot Market

Prices are a key outcome of markets. Prices vary across hours, across days and across years, and prices vary for multiple reasons. Prices are an indicator of the level of competition in a market, although 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 mark up index is a direct measure of that relationship. Prices in PJM, LMPs, are 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.

PJM average prices increased in 2001 over 2000 for several reasons including increased fuel costs and relatively short periods of high load conditions. The simple hourly average system-wide LMP was 15.1% higher in 2001 than in 2000, $32.38/MWh versus $28.14/MWh and 14.3% higher than in 1999.[1] (Table 3.) When hourly load levels are reflected, the load-weighted LMP of $36.65/MWh in 2001 was 19.3% higher than in 2000 and 7.6% higher than in 1999. (Table 5.) The load-weighted result reflects the fact that market participants typically purchase more energy during high price periods. However, when increased fuel costs are accounted for, the average fuel cost adjusted, load-weighted LMP in 2001 was 7.6% higher than in 2000, $33.05/MWh compared to $30.72/MWh. (Table 6.) Thus, after accounting for both the actual pattern of loads and the increased costs of fuel, average prices in PJM were 7.6% higher in 2001 than in 2000.

Prices rose to their highest levels of the year during the week of August 6, 2001 when new levels of peak demand were established on three successive days. During 2001, PJM average prices exceeded $900/MWH for 10 hours and exceeded $150/MWH for 60 hours. While prices during most hours reflected the interaction of demand and lower-price energy offers, prices on high load days reflected a combination of market power and scarcity. Prices reflected economic scarcity because loads exceeded the energy available from units operating within PJM at prices equal to marginal costs. Prices reflected market power because a significant block of MW offered their energy at prices exceeding marginal cost and exceeding the price of available imports. The interaction of high levels of demand and the supply offers from this high-priced block resulted in higher prices. Competition from imports responding to these prices limited the duration of high prices. If the impact of prices during the high load week of August 6 were excluded, the average load-weighted, fuel cost adjusted price would have been $29.98, a 5.7% decrease from 2000.

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

Energy market price levels are consistent with the conclusion that the energy market was reasonably competitive in 2001.

Figure 10 compares the PJM system-wide price duration curves for 1998, 1999, 2000, and 2001. A price duration curve represents the percent of hours that LMP was at or below a given price for the year. Figure 10 shows that there was relatively little difference in LMPs for 60% of the hours in each of the four years, for 96% of the hours in 2000 and 2001, and for more than 96% of the hours in 1998 and 1999. Figure 11 compares the price duration curves for hours above the 95th percentile. Figure 11 shows that prices greater than $150/MWh occurred in each year for about 1% or less of the hours.

As can be seen in Figures 10 and 11, LMPs exceeded $900/MWh in 1998, 1999, and 2001. In 1998 and 1999, the highest prices occurred during the hot, summer months. Prices were above $900/MWh for a total of 35 hours during these two summers. In 2001, the highest LMPs occurred during a single period of hot weather in the week of August 6, when new system peak loads occurred on three consecutive days, August 7, 8 and 9. During these three days, prices exceeded $900/MWh for 10 hours. As a result of relatively mild weather, LMPs in 2000 did not reach the levels obtained in the other years, and did not exhibit the same volatility.

Figure 10

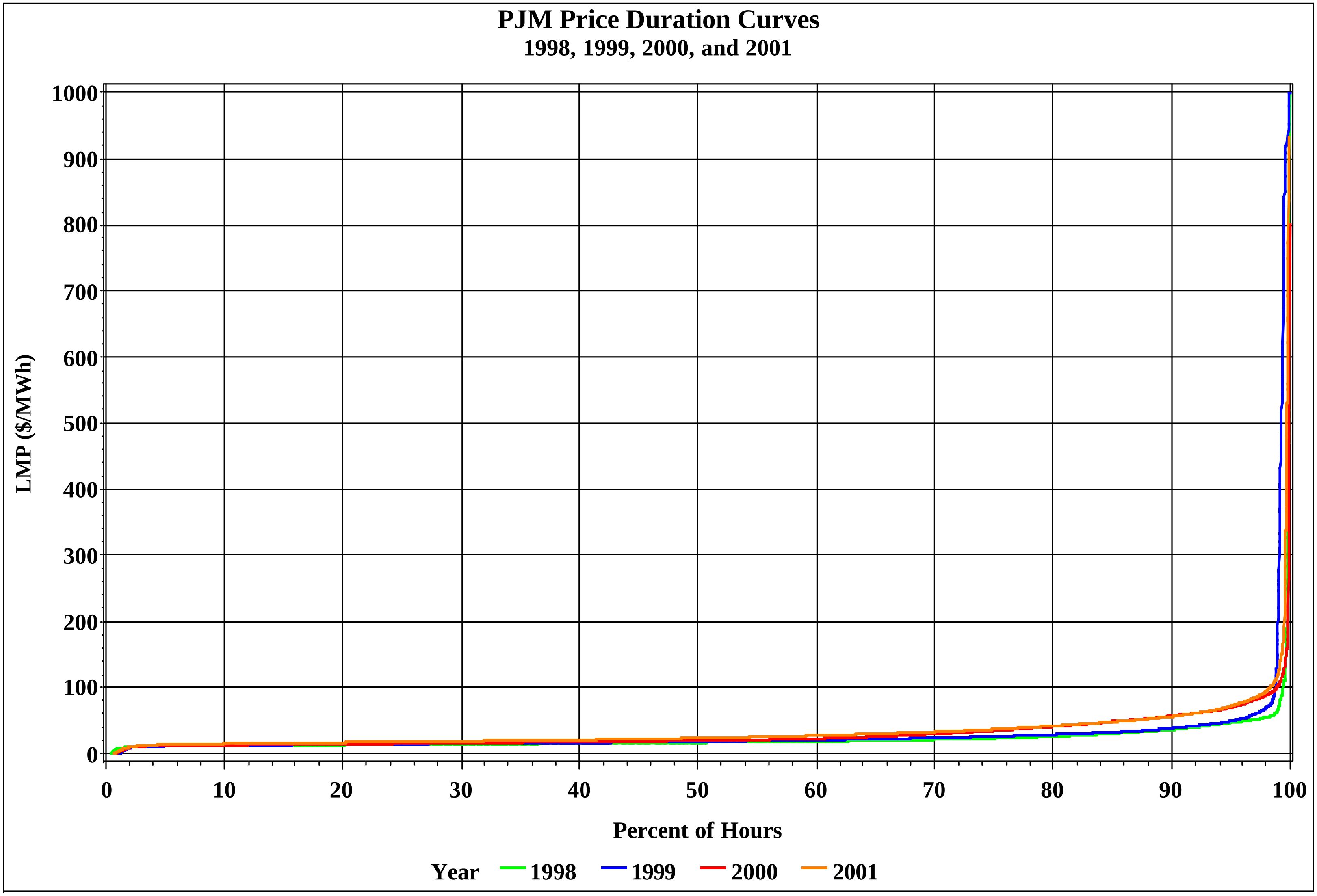
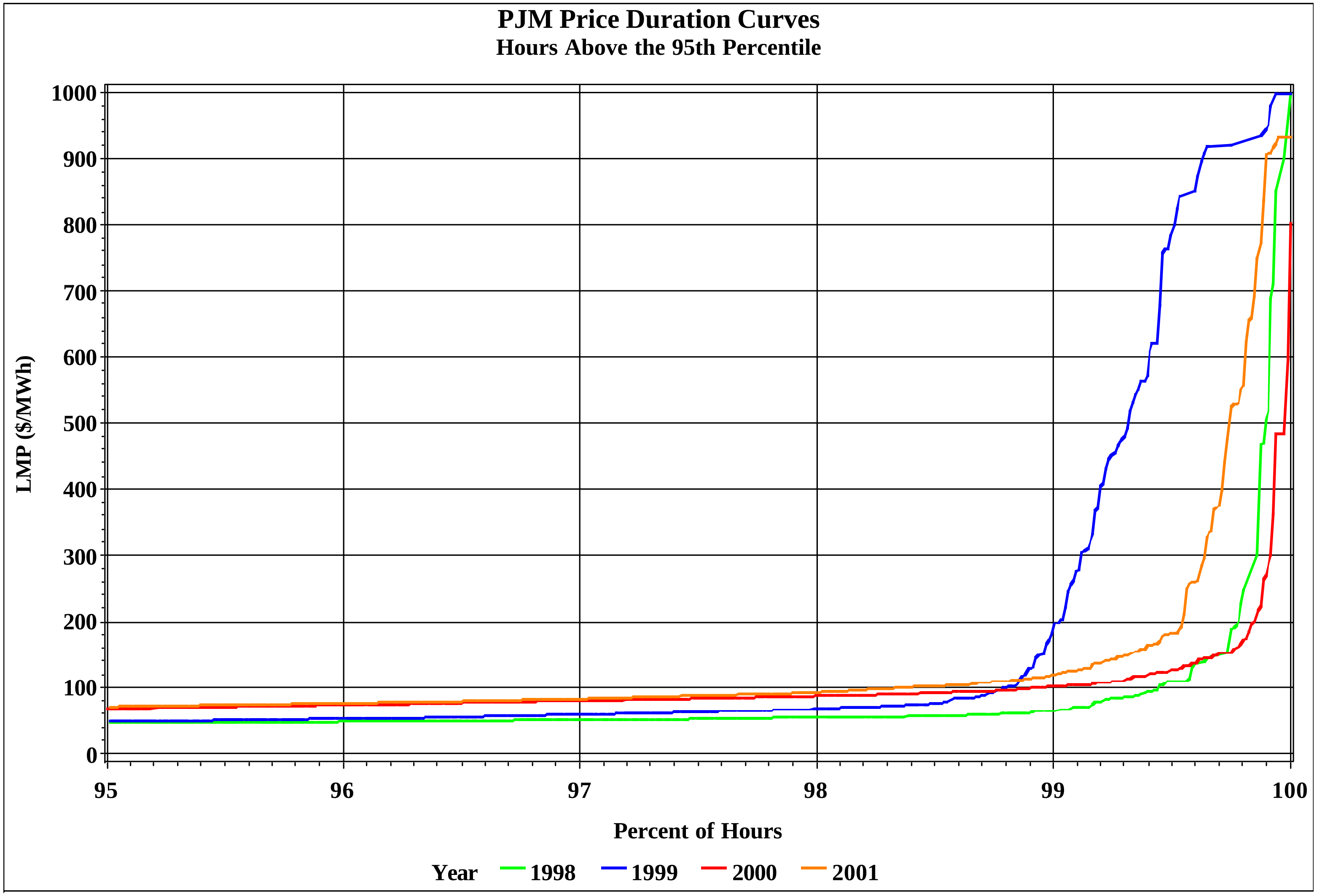

PJM Price Duration Curves
1998, 1999, 2000, and 2001
LMP ($/MWh)
1000
900
800
700
600
500
400
300
200
100
0
0
10
20
30
40
50
60
70
80
90
100
Percent of Hours
Year
1998
1999
2000
2001

Figure 11



PJM Price Duration Curves
Hours Above the 95th Percentile
LMP ($/MWh)
1000
900
800
700
600
500
400
300
200
100
0
95
96
97
98
99
100
Percent of Hours
Year
1998
1999
2000
2001

Table 3 provides summary LMP statistics for the years from 1998 to 2001. The annual statistics were calculated from the hourly-integrated PJM system-wide LMPs (and MCPs for January – March 1998).[2] Average system-wide LMP was about 15% higher in 2001 than 2000. The median[3] LMP was more than 20% higher in 2001 than in 2000, 29% higher than in 1999, and 38% higher than 1998. The standard deviation[4] of average LMP is lowest in 2000 relative to the other years, reflecting the hotter summers in 1998, 1999, and 2001.

Table 3: PJM Average Hourly LMP ($/MWh)

				Year Over Year Percent Change		
	Average LMP	**Median LMP**	**Standard Deviation**	**Average LMP**	**Median LMP**	**Standard Deviation**
1998	21.72	16.60	31.45			
1999	28.32	17.88	72.41	30.4%	7.7%	130.2%
2000	28.14	19.11	25.69	-0.6%	6.9%	-64.5%
2001	32.38	22.98	45.03	15.1%	20.3%	75.3%

Load – 1998, 1999, 2000 and 2001

Figure 12 shows the load duration curve for the years 1998, 1999, 2000 and 2001. Figure 12 indicates that load in 2001 was virtually identical to load in 2000 for slightly more than 90% of the hours, with load in 2001 reaching higher levels for about 10% of the hours due in part to the hot week of August 6. Indeed, new peak demand was set on three consecutive days during this week, surpassing the previous peak demand of 51,700 MW established in July 1999. On August 7 a new peak demand of 53,071 MW was established; on August 8 a new peak demand of 53,531 MW was established; and on August 9 the final new peak demand of 54,014 MW was established.

Table 4 presents summary load statistics for the four years. The average load of 30,297 MW in 2001 was 0.6% higher than in 2000, 2.2% higher than in 1999, and 6% higher than in 1998. The median load in 2001 was also 0.2% higher than in 2000. The variability in load, indicated by the standard deviation, increased by 6.2% in 2001.[5]

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2 MCP is the single market clearing price calculated by PJM prior to implementation of LMP.

3 The median is defined as the midpoint of the data values. Fifty percent of the data values lie above the median and fifty percent lie below the median.

4 The standard deviation is a measure of the variability of the data around the mean. 68% of the data will lie within plus and minus one standard deviation from the mean.

5 See Appendix for more details on load frequency including on-peak and off-peak loads.

Figure 12

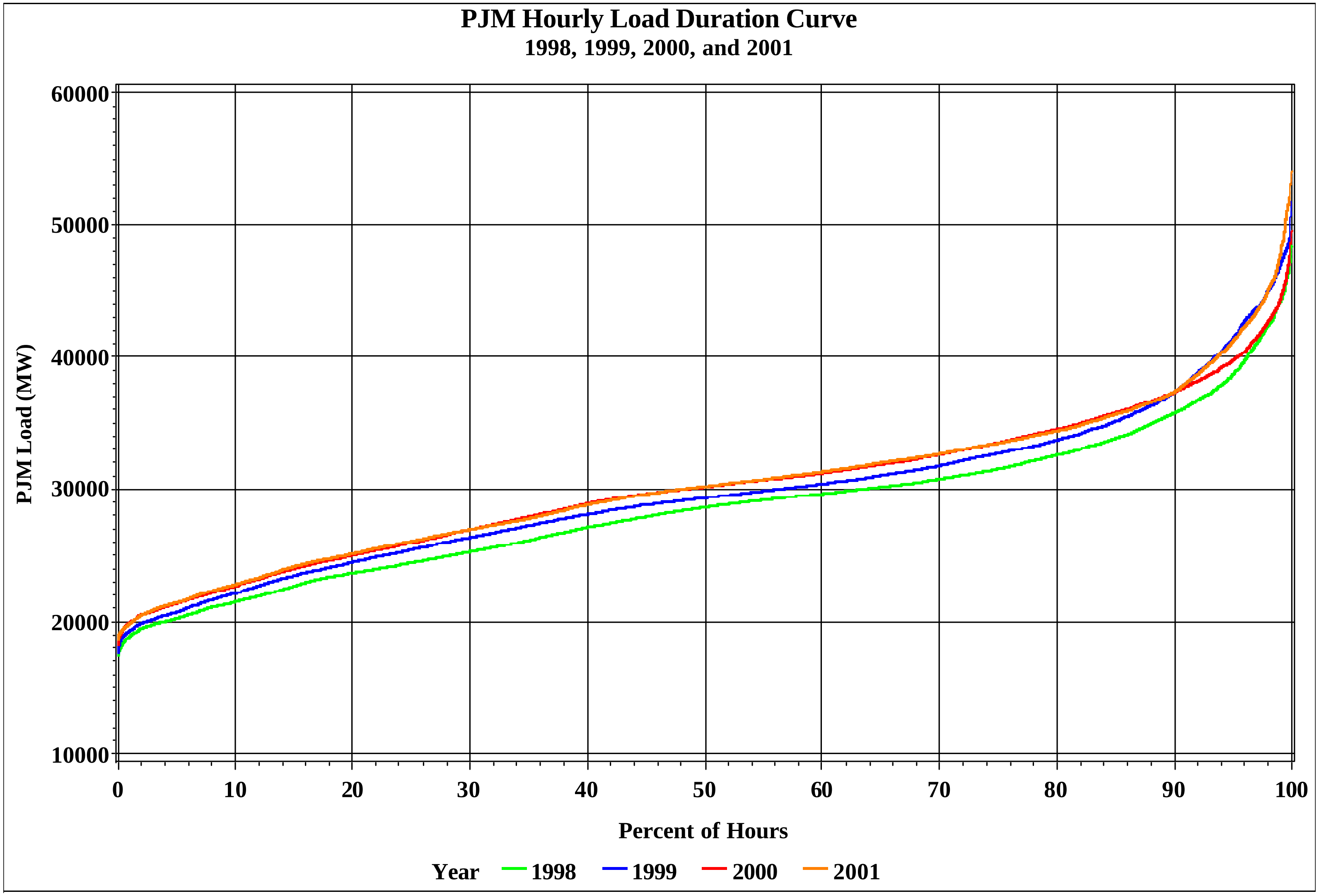

PJM Hourly Load Duration Curve
1998, 1999, 2000, and 2001
PJM Load (MW)
60000
50000
40000
30000
20000
10000
0
10
20
30
40
50
60
70
80
90
100
Percent of Hours
Year
1998
1999
2000
2001

Table 4: PJM Load (MW)						
				Year Over Year Percent Change		
	Average Load	Median Load	Standard Deviation	Average Load	Median Load	Standard Deviation
1998	28,577	28,653	5,512			
1999	29,640	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	-7.2%
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%

Load-Weighted Average LMP – 1998, 1999, 2000 and 2001

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

Table 5 shows that the load-weighted LMP of $36.65/MWh in 2001 was 19% higher than in 2000, 8% higher than in 1999, and 52% higher than in 1998. The median load-weighted LMP in 2001 was 22% higher than in 2000, 32% higher than in 1999, and 43% higher than in 1998. The standard deviation of the load-weighted average LMP in 2001 was 37% lower than in 1999, but higher than in 1998 and 2000. Comparing the average load-weighted LMPs in Table 5 with the average hourly LMPs presented in Table 3, in 2001 the load-weighted average LMP is 13% higher than the hourly average LMP, in 2000 it is 9% higher, in 1999 it is 20% higher, and in 1998 it is 11% higher.[6]

Table 5: PJM Load-Weighted Average LMP ($/MWh)						
				Year Over Year Percent Change		
	Average LMP	Median LMP	Standard Deviation	Average LMP	Median LMP	Standard Deviation
1998	24.16	17.60	39.29			
1999	34.06	19.02	91.49	41.0%	8.1%	132.9%
2000	30.72	20.51	28.38	-9.8%	7.8%	-69.0%
2001	36.65	25.08	57.26	19.3%	22.3%	101.8%

Fuel Cost Adjusted LMPs – 2000 and 2001

To control for differences between 2000 and 2001 average load-weighted LMPs caused by differences in fuel costs between the two years, the year 2001 load-weighted LMPs were adjusted to reflect changes in fuel costs. This weighting procedure takes account of both the change in prices of the fuels used by the marginal units and of the change in marginal MW generated using each fuel type.[7]

6 See Appendix for details on peak and off-peak load-weighted LMPs.

7 See Appendix for fuel cost adjustment method.

Table 6 compares 2001 load-weighted, fuel cost adjusted average LMPs to 2000 load-weighted average LMPs. The table shows that after adjusting for fuel price changes between the two years, average load-weighted LMP in 2001 was 7.6% higher than in 2000, $33.05/MWh compared to $30.72/MWh. Thus, if fuel prices had been the same in 2001 as in 2000, the 2001 load-weighted LMP would have been about 10% lower, $33.05/MWh instead of $36.65/MWh, or an 8% increase over 2000.[8] In other words, more than half the 19% increase in the load-weighted LMP between 2000 and 2001 was the result of increased fuel costs. The increase in the median load-weighted, fuel cost adjusted LMP was 14.5%, $23.49/MWh in 2001 to $20.51/MWh in 2000. The standard deviation of load-weighted, fuel cost adjusted LMP was 95% higher in 2001 than 2000.

Table 6: Load-Weighted, Fuel Cost Adjusted LMPs ($/MWh)

	2000	2001	% Increase
Average LMP	30.72	33.05	7.6%
Median LMP	20.51	23.49	14.5%
Standard Deviation	28.38	55.34	95.0%

Day-Ahead and Real-Time Market LMPs

The day-ahead market was introduced on June 1, 2000. The day-ahead and real-time market comparisons that follow are for calendar year 2001. It would be expected that competition would cause the prices in the day-ahead and real-time markets to tend to converge. On average, day-ahead prices were slightly greater than real-time prices during 2001. Figure 13 shows the price duration curve for the two markets, while Figure 14 shows the price duration curve for hours above the 95th percentile. Real-time prices are slightly lower than day-ahead prices for the lowest priced 80% of the hours and are higher for the remaining 20% of the hours while the difference increases in the highest priced 1% or less of the hours. This difference reflects in part the price levels in real time during the hot week of August 6, which were not fully anticipated in the day-ahead market. Figure 15 compares average day-ahead and real-time LMPs for each hour. Figure 16 shows the difference between real-time hourly LMP and day-ahead hourly LMP (real-time LMP minus day-ahead LMP).[9]

8 See Appendix for details on LMPs during constrained hours.

9 See Appendix for more details on the frequency distribution of prices.

Figure 13

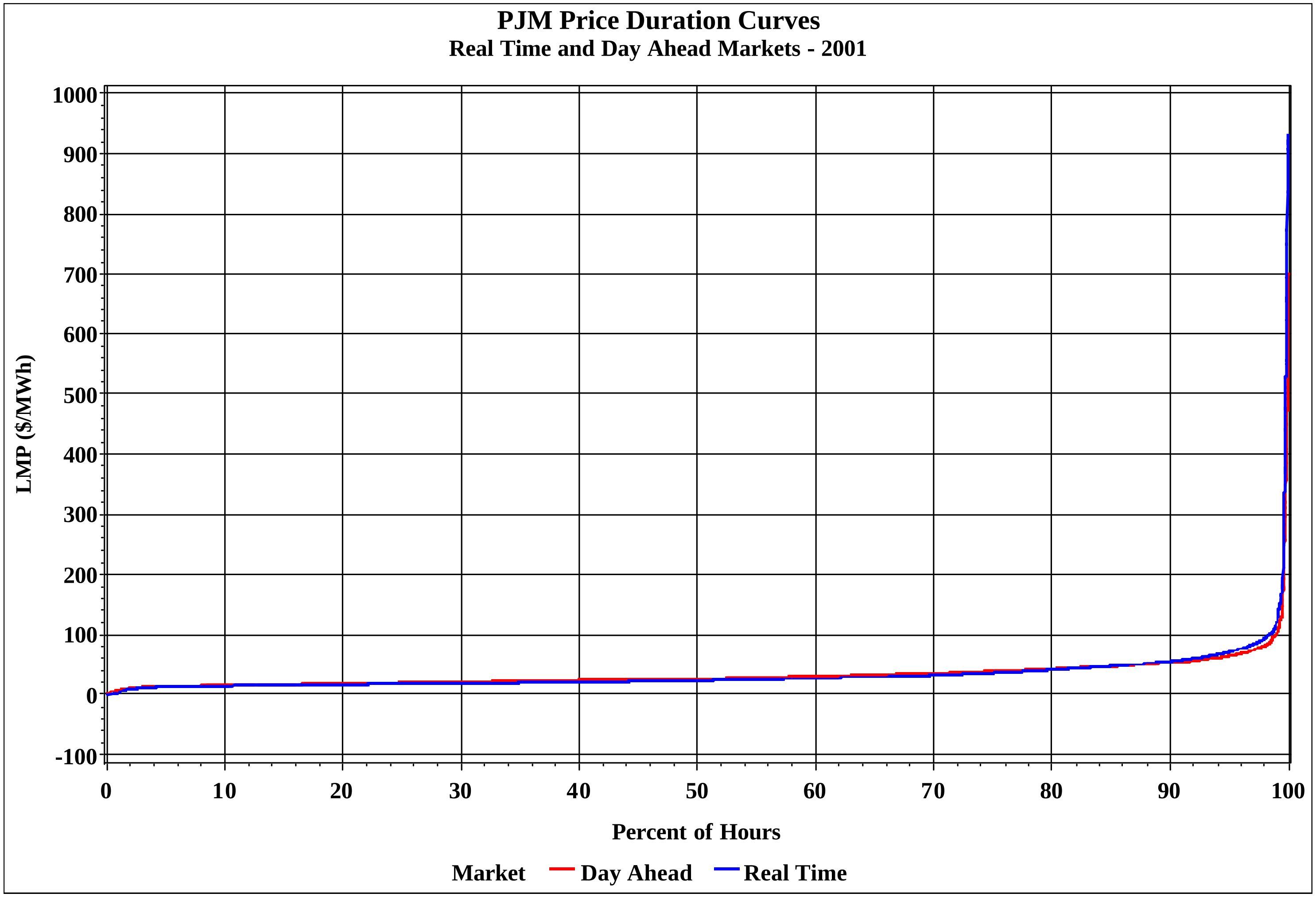

PJM Price Duration Curves
Real Time and Day Ahead Markets - 2001
LMP ($/MWh)
1000
900
800
700
600
500
400
300
200
100
0
-100
0
10
20
30
40
50
60
70
80
90
100
Percent of Hours
Market
Day Ahead
Real Time

Figure 14

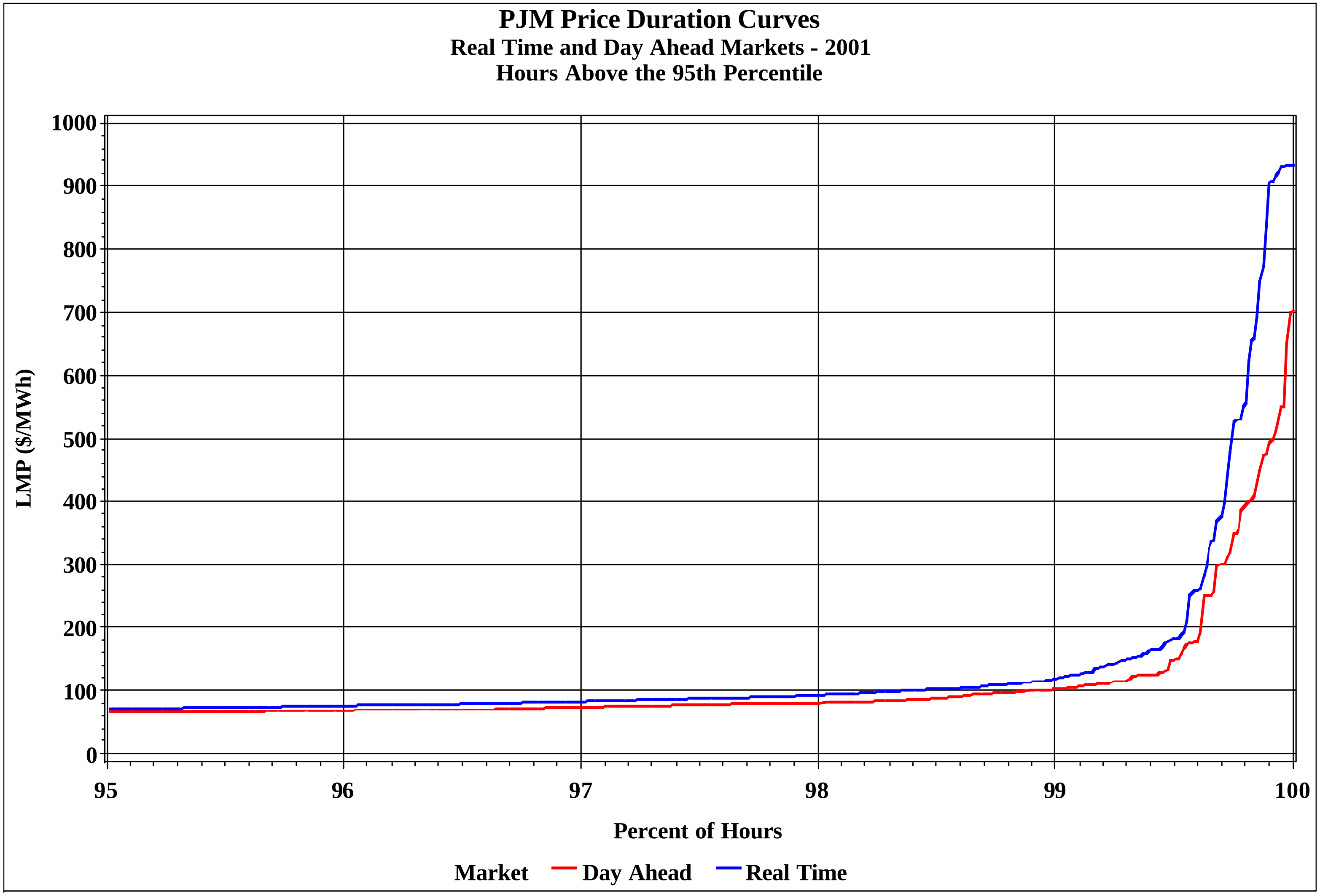
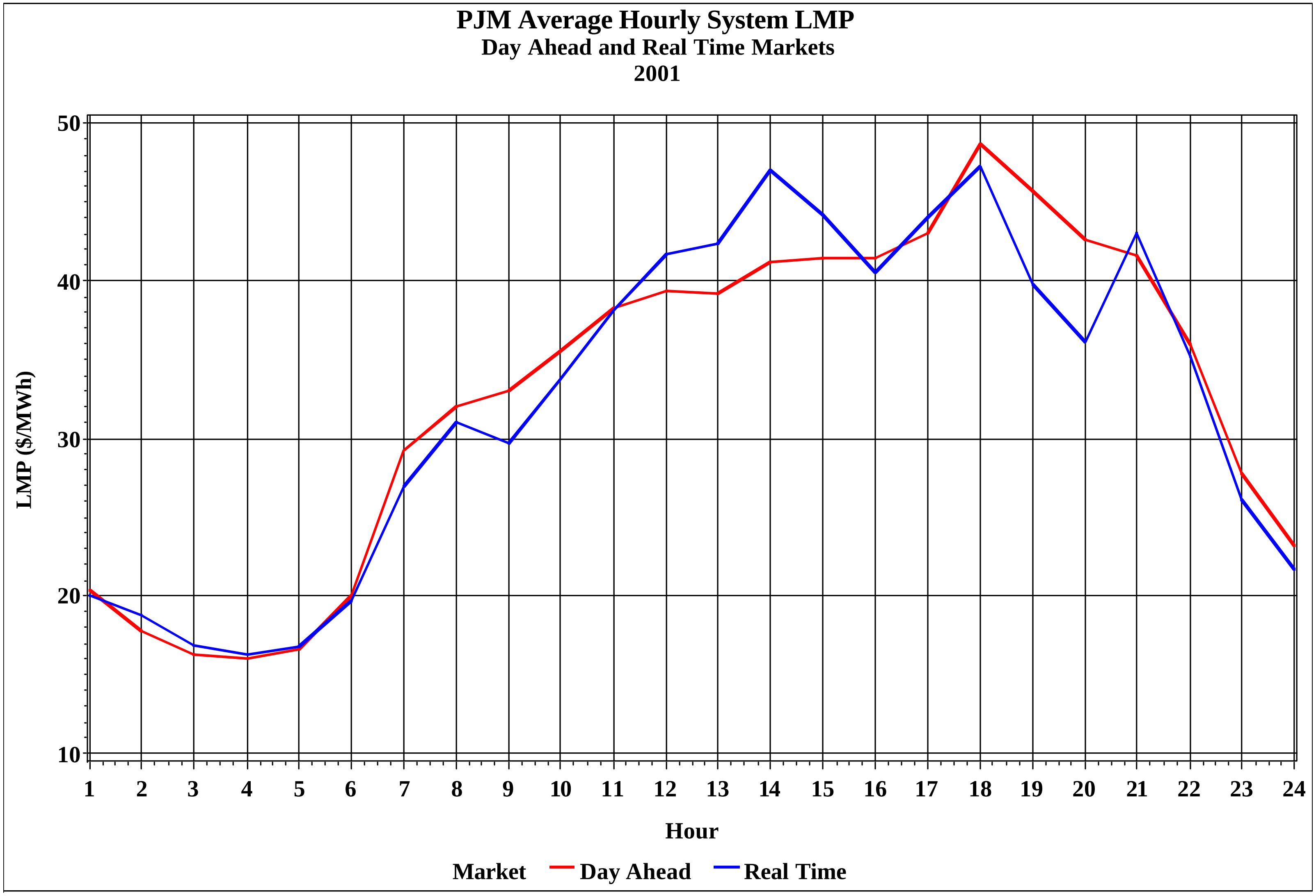
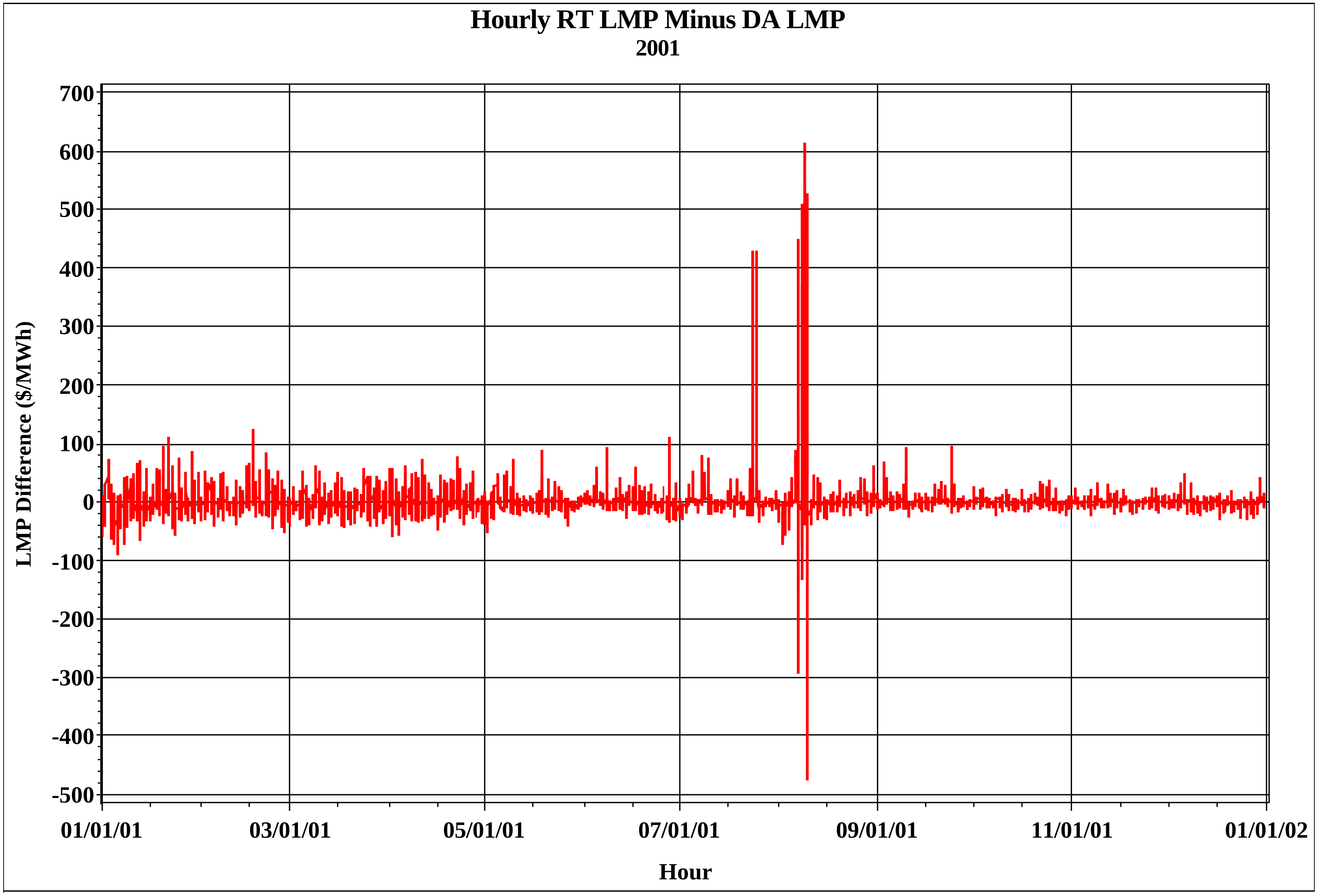

PJM Price Duration Curves
Real Time and Day Ahead Markets - 2001
Hours Above the 95th Percentile
LMP ($/MWh)
1000
900
800
700
600
500
400
300
200
100
0
95
96
97
98
99
100
Percent of Hours
Market
Day Ahead
Real Time

Figure 15



PJM Average Hourly System LMP
Day Ahead and Real Time Markets
2001
LMP ($/MWh)
50
40
30
20
10
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour
Market
Day Ahead
Real Time

Figure 16



Hourly RT LMP Minus DA LMP
2001
LMP Difference ($/MWh)
700
600
500
400
300
200
100
0
-100
-200
-300
-400
-500
01/01/01
03/01/01
05/01/01
07/01/01
09/01/01
11/01/01
01/01/02
Hour

Figure 16 shows that the difference between day-ahead and real-time prices narrowed during 2001, excluding the week of August 6.

Table 7 presents summary statistics for the two markets. The average LMP in the day-ahead market was $0.37/MWh or 1.1% higher than the average LMP in the real-time market. The day-ahead median LMP was 17.7% larger than the real-time LMP, an average difference of $4.07/MWh. Consistent with the price duration curve, price dispersion in the real-time market is 32.5% higher than the day-ahead market, with the average difference in standard deviation between the two markets of $14.61/MWh.[10] [11]

Table 7: Comparison of Real-Time and Day-Ahead Market LMPs ($/MWh)				
	Day-Ahead	**Real-Time**	**Average Difference**	**Percent Over Real-Time**
Average LMP	32.75	32.38	-0.37	1.1%
Median LMP	27.05	22.98	-4.1	17.7%
Standard Deviation	30.42	45.03	14.6	-32.5%

Day-Ahead and Real-Time Market Generation and Load

Day-Ahead and Real-Time Generation

There are three types of "generation" in the day-ahead market – self-scheduled generation, generator offers, and increment offers. Self-scheduled generation 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. Generator offers are schedules of MW offered and the corresponding offer price. Finally, increment offers are financial offers in the day-ahead market to supply a specified amount of MW at, or above, a given price. In all cases, commitments made and cleared in the day-ahead market are financially binding. Real-time generation is the actual production of electricity during the operating day.

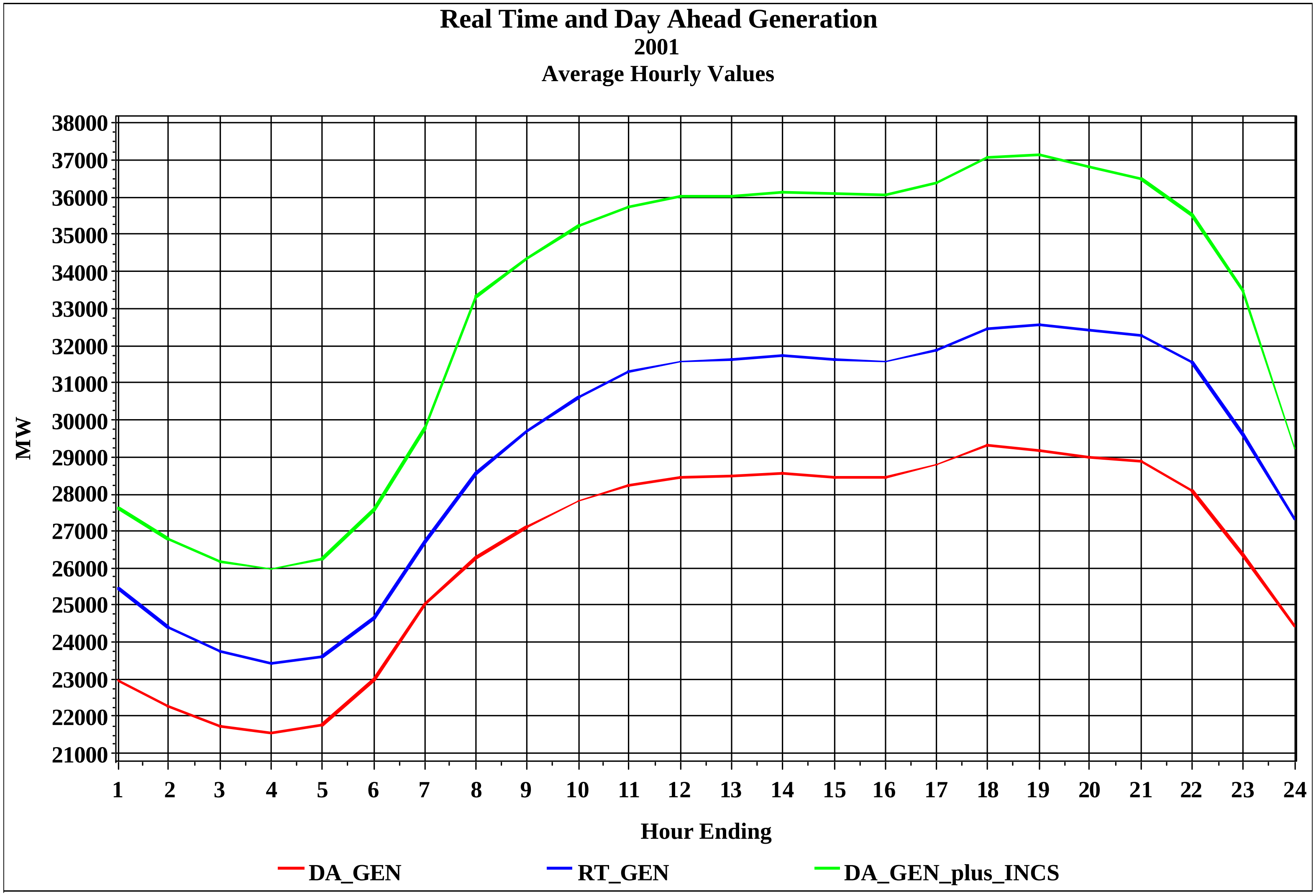
Figure 17 shows the average hourly values of day-ahead generation, day-ahead generation plus increment offers, and real-time generation. Day-ahead generation is generation that is cleared in the day-ahead market. Real-time generation is always higher than day-ahead generation. However, when increment offers are added to day-ahead generation, total day-ahead MW offers always exceed real-time generation.

Table 8 presents summary statistics for day-ahead and real-time generation and the average differences between the two. The table shows that real-time generation averaged 2,757 MW more than day-ahead generation.

[10] See Appendix for more details on peak and off-peak LMPs.

[11] See Appendix for more details on LMPs during constrained hours.

Figure 17


Real Time and Day Ahead Generation
2001
Average Hourly Values
MW
38000
37000
36000
35000
34000
33000
32000
31000
30000
29000
28000
27000
26000
25000
24000
23000
22000
21000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour Ending
DA_GEN
RT_GEN
DA_GEN_plus_INCS

When increment offers are added to day-ahead generation offers, the sum in the day-ahead market is 3,790 MW higher than real-time generation.

Table 8: Day-Ahead and Real-Time Generation (MW)					
	Day-Ahead		**Real-Time**	**Average Difference**	
	Generation	**Increment Offers**	**Generation**	**Generation**	**DA Generation Plus Increment Offers**
Average MW	26,423	6,547	29,180	2,757	3,790
Median MW	26,002	6,284	28,977	2,715	3,549
Standard Deviation	4,767	2,172	5,315		

As can be seen in Figure 17, the differences among the three types of day-ahead generation offers widen during peak hours (hours ending 8 to 23). Table 9 shows the average MW values in the day-ahead and real-time markets during the off-peak and peak hours, while Table 10 shows the average differences during the two periods. Real-time generation exceeds day-ahead generation during both periods. The average difference between real-time and day-ahead generation during off- peak hours is 2,216 MW, and the average difference during peak hours is

Table 9: Day-Ahead and Real-Time Peak and Off-Peak Generation (MW)						
	Day-Ahead				**Real-Time**	
	Off-Peak	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**
	Generation	**Generation**	**Increment Offers**	**Increment Offers**	**Generation**	**Generation**
Average MW	23,897	29,320	5,199	8,094	26,114	32,697
Median MW	23,481	28,183	5,045	7,824	25,685	31,549
Standard Deviation	3,620	4,248	1,339	1,894	3,925	4,453

3,377 MW. When increment offers are added to day-ahead generation, the total exceeds real-time generation during both periods. During off-peak hours, day-ahead generation plus increment offers averaged 2,982 MW more than real-time generation, and during peak hours, day-ahead generation plus increment offers averaged 4,716 MW more than real-time generation.

Table 10: Average Differences Between Day-Ahead and Real-Time Markets (MW)				
	Off-Peak		Peak	
	Generation	Generation Plus Increment Offers	Generation	Generation Plus Increment Offers
Average MW Difference	2,216	2,982	3,377	4,716
Median MW Difference	2,211	2,904	3,415	4,626

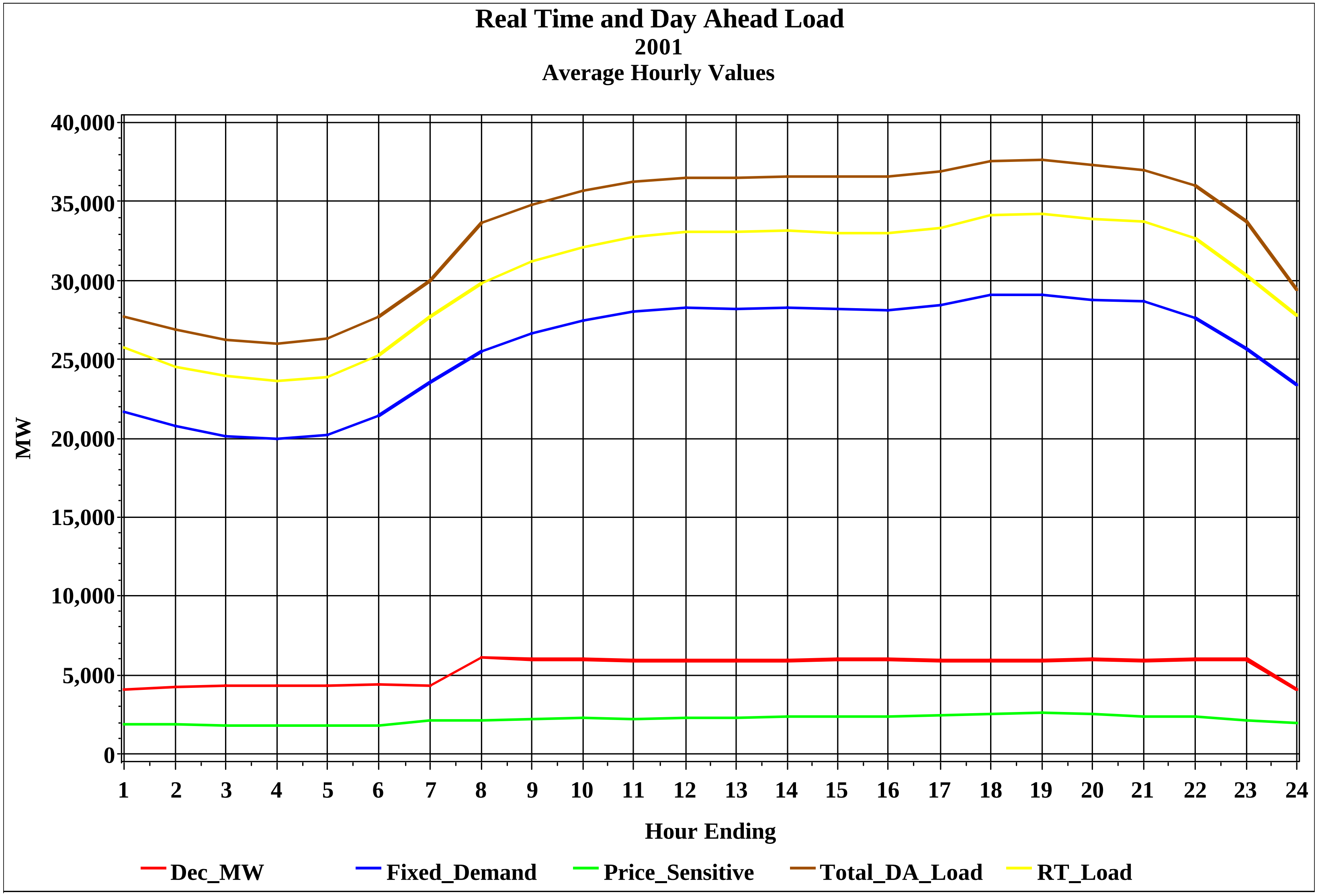
Day-Ahead and Real-Time Load

There are three types of load in the day-ahead market. Fixed demand bids represent load that will purchase a defined MW level of energy, regardless of the level of LMP. Price sensitive bids represent load that will purchase a defined MW level of energy only up to a specified LMP; above that LMP, the load bid is zero. Decrement bids are similar to price sensitive bids in that they represent load that will purchase a defined MW level of energy up to a specified LMP and are zero above that LMP. However, decrement bids are financial bids that can be submitted by any market participant. All load bids that are cleared in the day-ahead market are financially binding. Real-time load is the actual load on the system during the operating day.

Figure 18 shows the average hourly values of day-ahead fixed demand, price sensitive load, decrement bids, and total day-ahead and real-time load (total day-ahead load is defined here as the sum of the three demand components). Table 11 presents the summary statistics for the 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 18 and Table 11 show, total day-ahead load was higher than real-time load by an average of 3,026 MW. The table also shows that fixed demand is the largest component of day-ahead load, 77%, while price sensitive was the smallest component, 7%, with decrement bids accounting for the remaining 16% of day-ahead load.

Table 11: Day-Ahead and Real-Time Load (MW)						
	Day-Ahead				Real-Time	
	Fixed Demand	Price Sensitive	Decrement Bids	Total DA Load	Total RT Load	Average Difference
Average MW	25,741	2,195	5,383	33,318	30,297	3,026
Median MW	25,420	2,144	5,159	32,812	30,219	2,983
Standard Deviation	5,234	640	1,403	6,489	5,873	

Figure 18


Real Time and Day Ahead Load
2001
Average Hourly Values
MW
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour Ending
Dec_MW
Fixed_Demand
Price_Sensitive
Total_DA_Load
RT_Load

As can be seen in Figure 18, the day-ahead load components (except for price sensitive demand) increased during the peak hours (hours ending 8 to 23), as did real-time load. Table 12 shows the average load MW values in the day-ahead and real-time markets during the off-peak and peak hours. Total day-ahead load was higher than real time load during both off-peak and peak hours. The average difference during off-peak hours was 2,483 MW, while the average difference during peak hours was 3,636 MW. The percentage of day-ahead load comprised by each of the components is similar during the two periods. Fixed demand accounts for the largest percentage of day-ahead load during the off-peak and peak periods, 77% during both periods, with price sensitive load accounting for the smallest percentage during both periods, 7% and 6%, respectively, and decrement bids accounting for 16% and 17%, respectively.

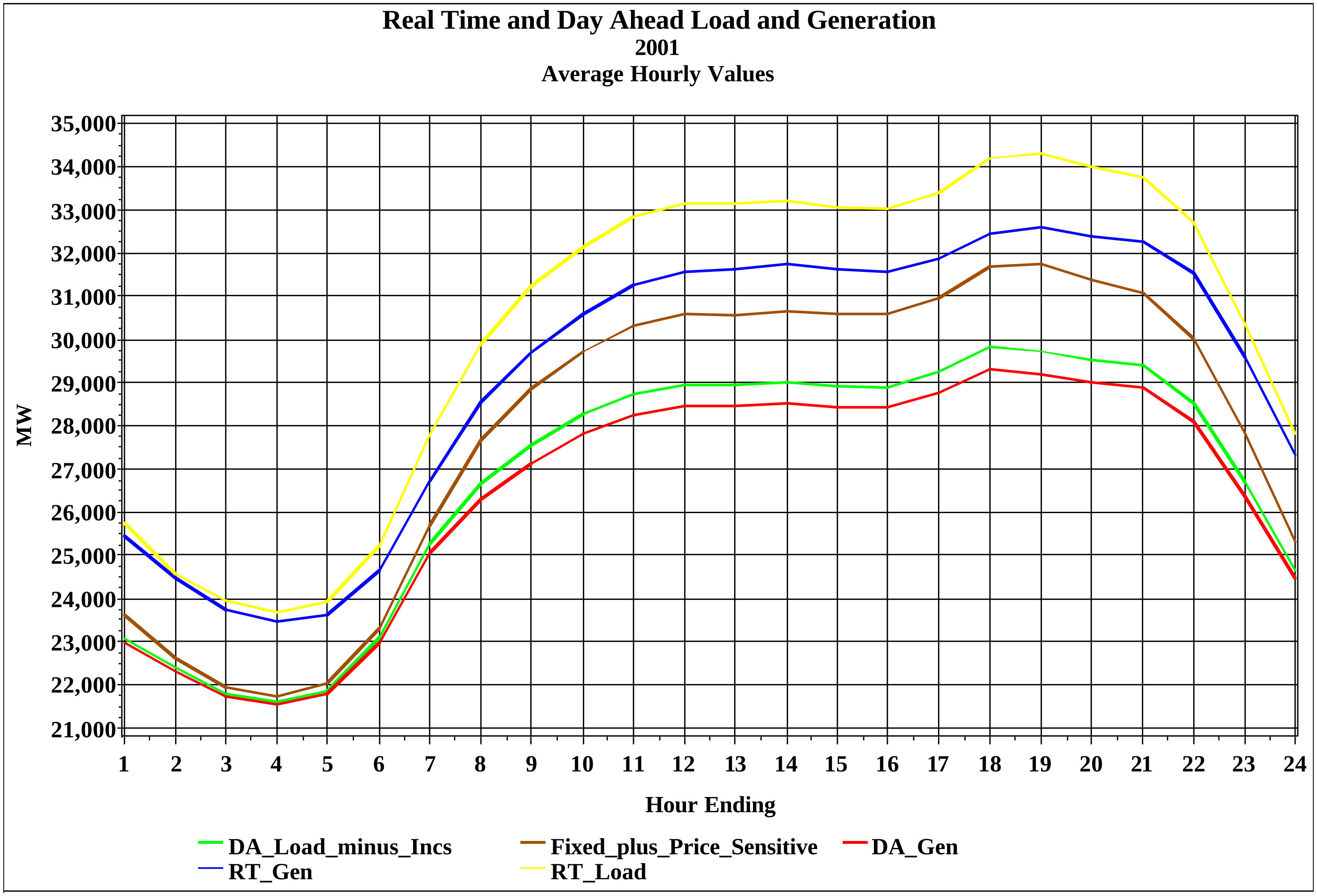
Table 12: Day-Ahead and Real-Time Load During Off-Peak and Peak Hours (MW)

	Day-Ahead								Real-Time	
	Off-Peak				Peak				Off-Peak	Peak
	Fixed Demand	Price Sensitive	Decrement Bids	Total Load	Fixed Demand	Price Sensitive	Dec Bids	Total Load	Total Load	Total Load
Average MW	22,629	2,074	4,584	29,287	29,307	2,334	6,298	37,939	26,804	34,303
Median MW	22,235	1,983	4,573	28,854	28,313	2,352	6,201	36,864	26,433	33,076
Standard Deviation	3,692	603	902	4,322	4,400	652	1,311	5,383	4,225	4,851

Figure 19 shows day-ahead and real-time load and generation. Note that increment offers have been subtracted from total day-ahead load. Since increment offers look like generation, subtracting increment offers from day-ahead load provides an estimate of day-ahead generation that must be turned on to meet the load.

Another difference between the two markets is the lower level of net external transactions (imports and exports) in the day-ahead market. In the real-time market, during peak hours, net transactions averaged 1,606 MW. During the same period in the day-ahead market, net transactions averaged 525 MW. A final observation is that there is a relatively constant difference between real-time load and day-ahead load excluding decrement bids; that is, day-ahead load as fixed plus price sensitive load. During off-peak hours the difference between real-time load and fixed plus price sensitive load averages 2,101 MW, while during peak hours the average difference is 2,662 MW.

Figure 19



Real Time and Day Ahead Load and Generation
2001
Average Hourly Values
MW
35,000
34,000
33,000
32,000
31,000
30,000
29,000
28,000
27,000
26,000
25,000
24,000
23,000
22,000
21,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour Ending
DA_Load_minus_Incs
Fixed_plus_Price_Sensitive
DA_Gen
RT_Gen
RT_Load

Appendix

Frequency Distribution of LMP

Figures A.1, A.2, A.3, and A.4 provide the frequency distribution, by hour, of LMPs for 1998, 1999, 2000 and 2001.[12] 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 LMPs were within a given $10 price interval.[13]

Comparing the figures, it can be seen that LMPs were most frequently in the interval $10/MWh to $20/MWh in each year. However, a decreasing percentage of hours fell in this interval in each succeeding year: 65% in 1998; 58% in 1999; 51% in 2000; and 36% in 2001. In 1998, 1999, 2000, and 2001, prices were less than $30/MWh 85%, 83%, 71%, and 66% of the hours, respectively. LMPs were less than $60/MWh 99%, 97%, 92%, and 92% of the hours, respectively, and less than $100/MWh 99.4%, 98.8%, 98.9%, and 98.4% of the hours, respectively. LMP was $150/MWh or greater for 60 hours (0.7% of the hours) in 2001, 27 hours (0.3% of the hours) in 2000, 95 hours (1% of the hours) in 1999, and 29 hours (0.3% of the hours) in 1998.

Frequency Distribution of Load

Figures A.5, A.6, A.7, and A.8 provide the frequency distribution, by hour, of LMPs for 1998, 1999, 2000 and 2001. The figures show that in 1998 and 1999 load was most frequently in the range of 25,000 to 30,000 MW, 35% and 34% of the hours, respectively, and that load was less than 30,000 MW for 63% of the hours in 1998 and 56% of the hours in 1999. By contrast, load was most frequently in the range of 30,000 to 35,000 MW in 2000 and 2001, 34% of the hours in each year, and was less than 30,000 MW for 48% of the hours in each year. Load was less than 45,000 MW for 99% of the hours in both 1998 and 2000, and never exceeded 50,000 MW. Load was less than 45,000 MW for 98% of the hours in both 1999 and 2001. Load in 1999 exceeded 50,000 MW for 15 hours and for 53 hours in 2001. A new all-time peak demand was set in both years: 51,700 MW in 1999 and 54,014 in 2001.

On-Peak and Off-Peak Load

Table A.1 presents the summary load statistics for 1998 to 2001 for the off-peak and peak hours, while Table A.2 shows the percentage changes in load year to year. The peak period is defined for each weekday (Monday through Friday) as hour ending 0800 to hour ending 2300, excluding holidays. As can be seen from the table, in all four years peak load is about 30% higher than the off-peak load, while the median peak load ranges from 20% to 30% higher. Average load during peak hours in 2001 was about 1.6% higher than that in 2000, 3% higher than in 1999, and 6.1% higher than in 1998. Off-peak load in 2001 was 0.4% lower than in 2000, but higher than in 1999 and 1998, 1.5% and 6.1%, respectively.

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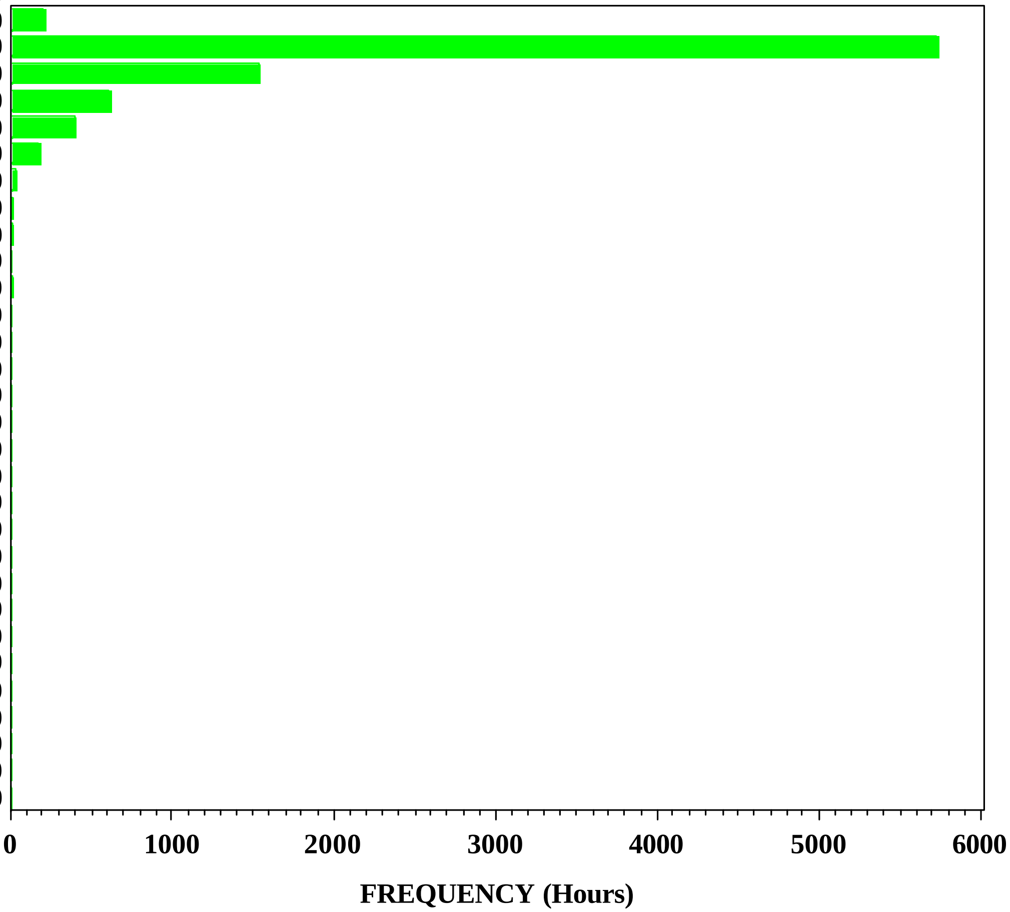
[12] LMPs were instituted in PJM in April, 1998. Prior to April, there was a single system price, the Market Clearing Price (MCP), which was the system lambda.

[13] Only LMP intervals with a positive frequency are included in the figure.

Figure A.1

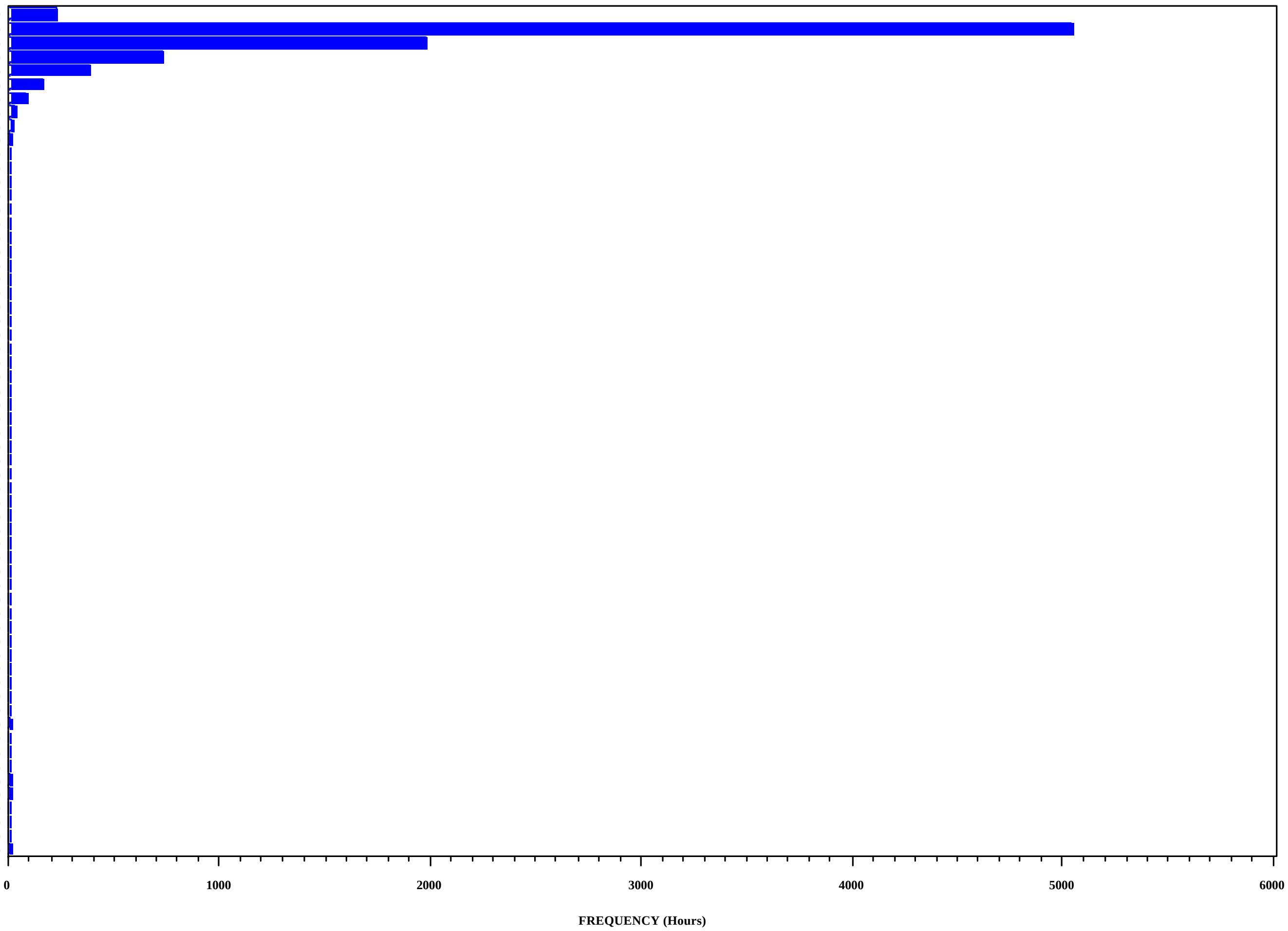
Frequency Distribution by Hours of PJM LMPs - 1998



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 to $1,000	2	8760	0.02	100.00

Figure A.2

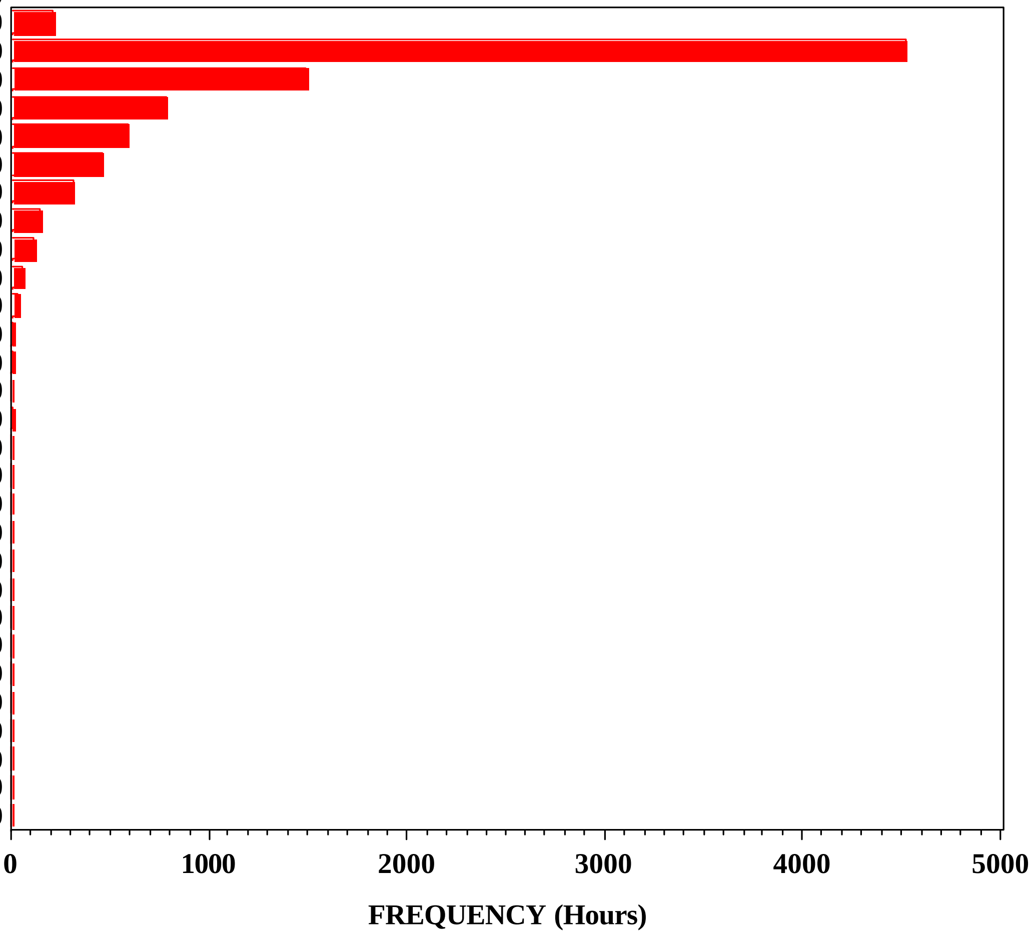
Frequency Distribution by Hours of PJM LMPs - 1999



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 to $1,000	7	8760	0.08	100.00

Figure A.3

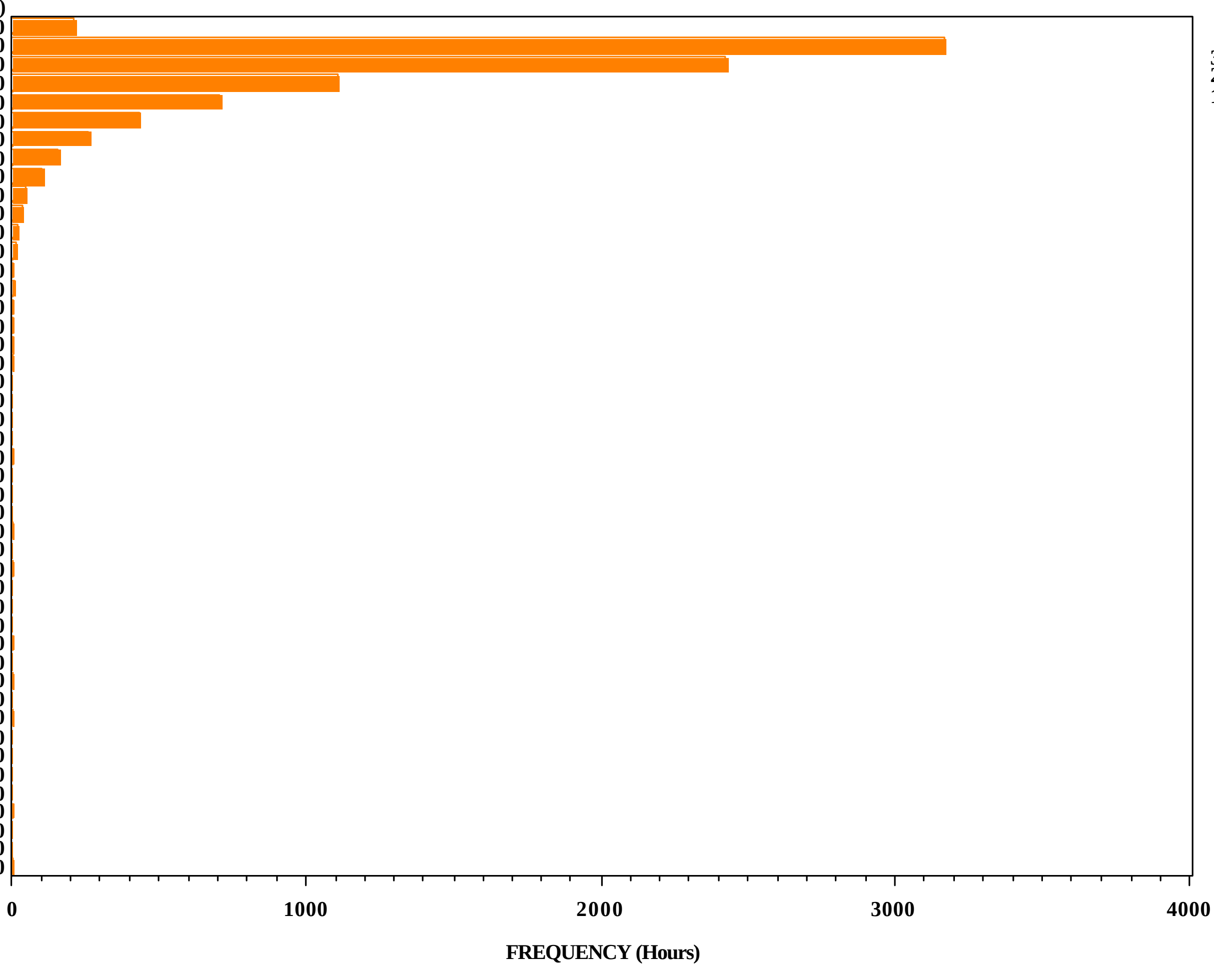
Frequency Distribution by Hours of PJM LMPs - 2000



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 A.4

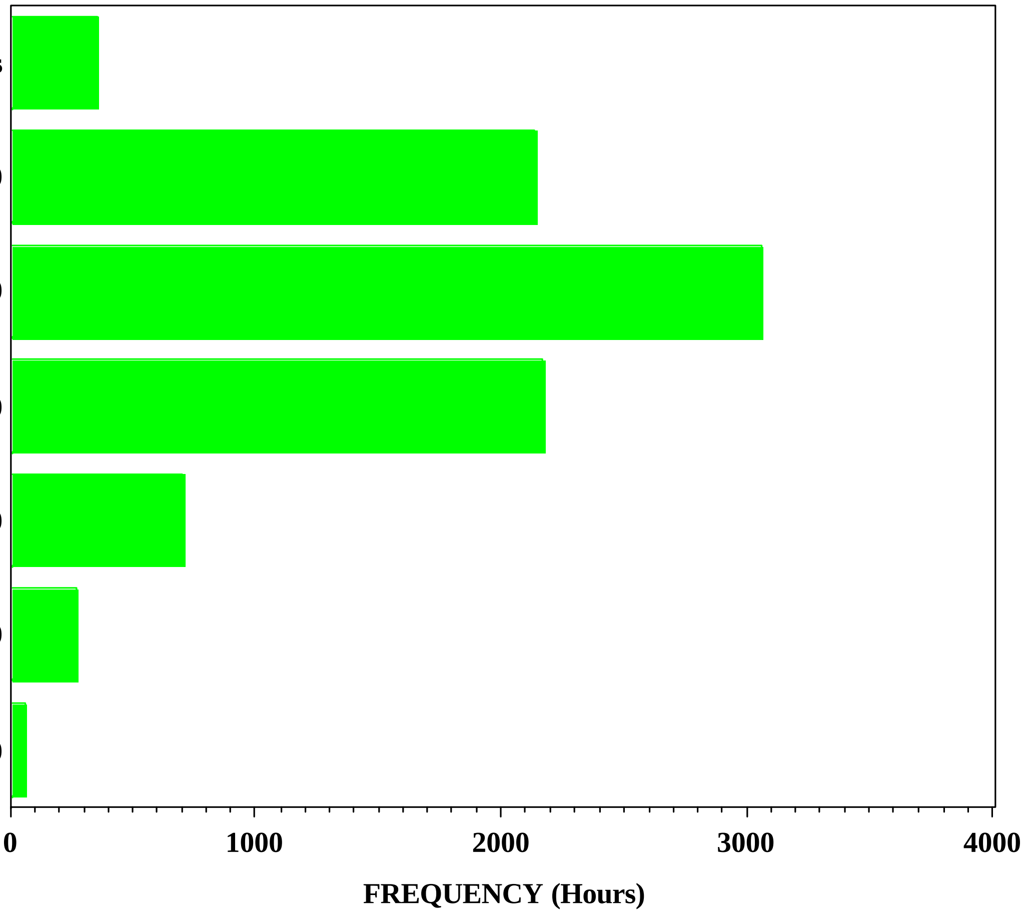
Frequency Distribution by Hours of PJM LMPs - 2001



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 A.5

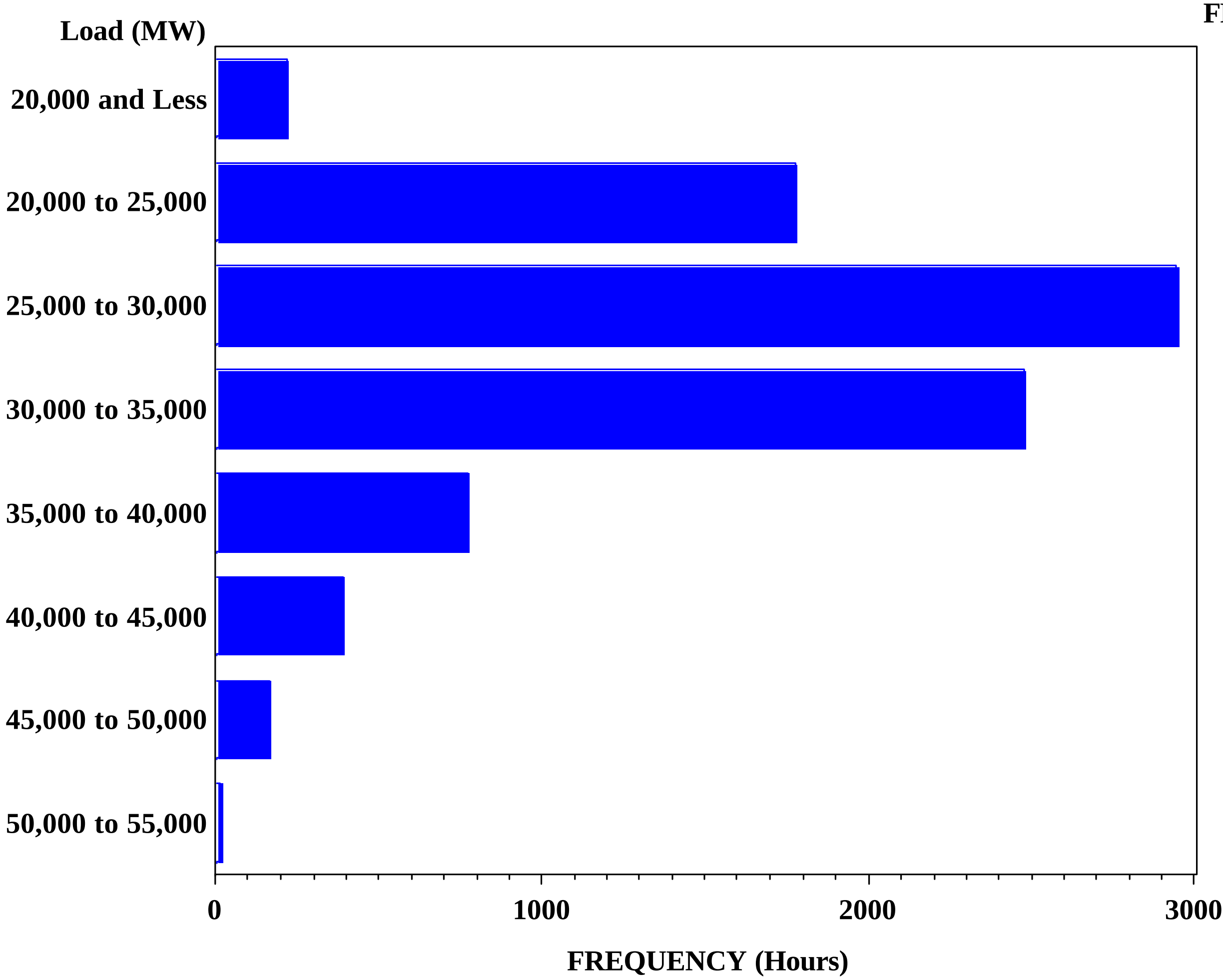
Frequency Distribution of Hourly PJM Load - 1998



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 A.6

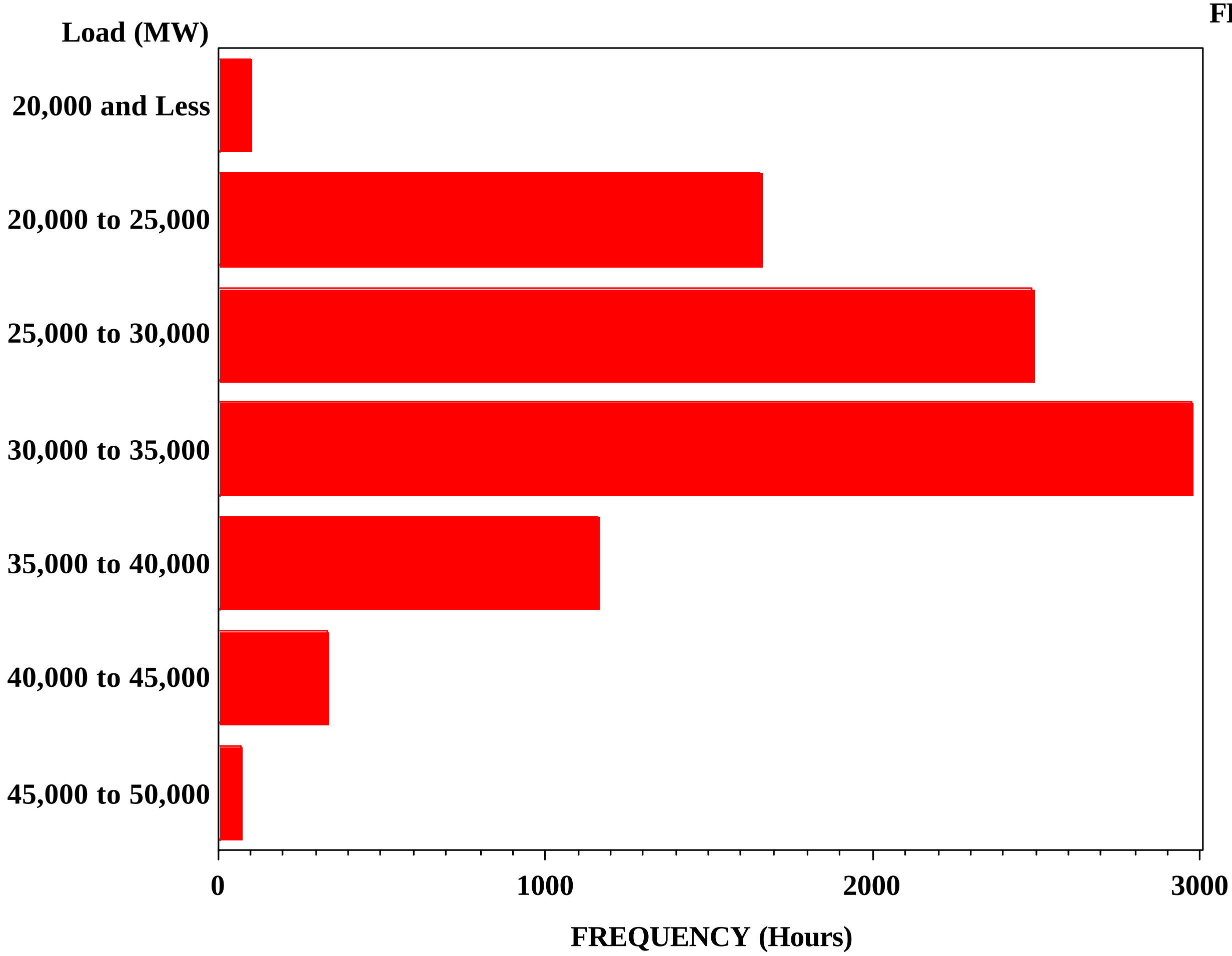
Frequency Distribution of Hourly PJM Load - 1999



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	33.61	56.37
30,000 to 35,000	2476	7414	28.26	84.63
35,000 to 40,000	773	8187	8.82	93.46
40,000 to 45,000	392	8579	4.47	97.93
45,000 to 50,000	166	8745	1.89	99.83
50,000 to 55,000	15	8760	0.17	100.00

Figure A.7

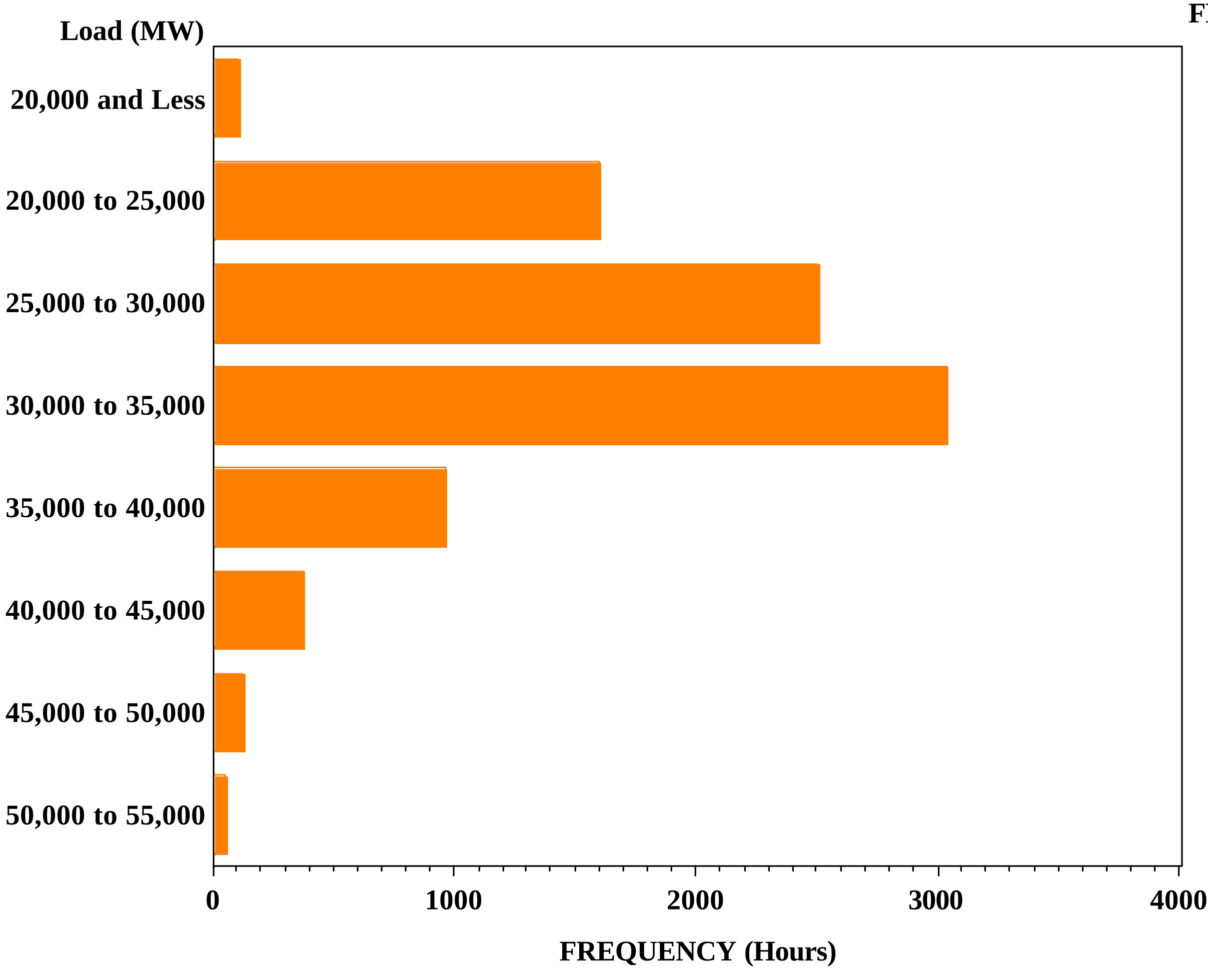
Frequency Distribution of Hourly PJM Load - 2000



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	99	99	1.13	1.13
20,000 to 25,000	1658	1757	18.88	20.00
25,000 to 30,000	2485	4242	28.29	48.29
30,000 to 35,000	2975	7217	33.87	82.16
35,000 to 40,000	1159	8376	13.19	95.36
40,000 to 45,000	337	8713	3.84	99.19
45,000 to 50,000	71	8784	0.81	100.00

Figure A.8

Frequency Distribution of Hourly PJM Load - 2001



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	107	107	1.22	1.22
20,000 to 25,000	1597	1704	18.23	19.45
25,000 to 30,000	2502	4206	28.56	48.01
30,000 to 35,000	3032	7238	34.61	82.63
35,000 to 40,000	965	8203	11.02	93.64
40,000 to 45,000	376	8579	4.29	97.93
45,000 to 50,000	128	8707	1.46	99.39
50,000 to 55,000	53	8760	0.61	100.00

Table A.1: Off-Peak and Peak Load – 1998, 1999, 2000, and 2001 (MW)									
	Average Load			Median Load			Standard Deviation		
Year	Off-Peak	Peak	Peak/ Off-Peak	Off-Peak	Peak	Peak/ Off-Peak	Off-Peak	Peak	Peak/ Off-Peak
1998	25,268	32,344	1.3	24,728	31,081	1.3	4,091	4,388	1.1
1999	26,409	33,291	1.3	25,795	31,987	1.2	4,862	4,870	1.0
2000	26,921	33,766	1.3	26,327	32,771	1.2	4,453	4,226	0.9
2001	26,804	34,303	1.3	26,433	33,076	1.3	4,225	4,851	1.1

Table A.2: Year Over Year Percent Change in Load						
	Average Load		Median Load		Standard Deviation	
Year	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak
1998						
1999	4.5%	2.9%	4.3%	2.9%	18.8%	11.0%
2000	1.9%	1.4%	2.1%	2.5%	-8.4%	-13.2%
2001	-0.4%	1.6%	1.4%	0.9%	-5.1%	14.8%

Peak and Off-Peak Load-Weighted LMPs – 2000 and 2001

Table A.3 shows the load-weighted average LMPs for 2000 and 2001 during the off-peak and peak periods. In 2000 the peak load-weighted LMP was 80% greater than the off-peak LMP, while in 2001 it was about 110% greater. The peak load-weighted average LMP in 2001 was 25% higher than in 2000, while the off-peak LMP in 2001 was 8% higher than in 2000. Both the peak and off-peak median LMPs were higher in 2001 than in 2000, 10% and 16%, respectively. The dispersion in LMPs, as indicated by the standard deviation, was higher in 2001 during peak hours, 138% higher than 2000, while the standard deviation of off-peak LMPs showed a 33% reduction in 2001.

Contrasting Tables A.3 with Table 5, the average on-peak load-weighted LMP in 2001 was 32% higher than the all-hours load-weighted average, while the off-peak load-weighted average LMP was 36% lower than the all-hours load-weighted average. Similarly, in 2000 the average on-peak load-weighted LMP was 26% higher than the all-hours load-weighted average, while the off-peak load-weighted average LMP was 29% lower than the all-hours load-weighted average.

Table A.3: Off-Peak and Peak Load-weighted LMPs – 2000 and 2001 ($/MWh)								
	2000			2001			% Change 2000 to 2001	
	Off-Peak	Peak	Peak/ Off-Peak	Off-Peak	Peak	Peak/ Off-Peak	Off-Peak	Peak
Average LMP	21.94	38.74	1.8	23.59	48.36	2.1	7.5%	24.8%
Median LMP	16.47	30.40	1.9	19.12	33.50	1.8	16.1%	10.2%
Standard Deviation	20.69	31.86	1.5	13.87	75.86	5.5	-33.0%	138.1%

Fuel Cost Adjustment

Fuel costs for 2000 and 2001 were taken from various published sources and then adjusted by the historical basis differential for that fuel. The near-month NYMEX gas futures contract was used for natural gas; Platts *Oilgram* New York Harbor Spot Cargo and Barge prices were used for petroleum products; the bi-monthly spot and contract prices from *Coal Outlook* were used for coal; and month-end uranium spot prices for 2000 and 2001 were obtained from the Ux Consulting Company, LLC and the Uranium Exchange Company.[14]

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 2000 and 2001 for which the price was determined by the marginal generating unit firing the indicated fuel. First, an index was calculated using 2000 fuel-specific MW as the weights: Year 2001 fuel-specific prices times Year 2000 fuel-specific MW divided by Year 2000 fuel-specific prices times Year 2000 fuel-specific MW. Second, an index was calculated using Year 2001 fuel-specific MW as the weights: Year 2001 fuel-specific prices times Year 2001 fuel-specific MW divided by Year 2000 fuel-specific prices times Year 2001 fuel-specific MW. The two indices were then chain-weighted by calculating their geometric mean. Each year 2001 monthly LMP was then divided by the chain-weighted price index for the month to derive the fuel cost adjusted LMP, which was then weighted by load to derive the load adjusted, fuel cost adjusted LMP.

LMPs During Constrained Hours – 2000 and 2001[15]

Figure A.9 shows the number of constrained hours during each month in 2000 and 2001 and the average number of constrained hours per month for each year. There were 3,853 constrained hours in 2000 and 4,823 in 2001, an increase of 25%. Figure A.9 also shows that although there were six months in 2000 when the number of constrained hours was higher than in 2001, the monthly average number of constrained hours was higher in 2001: 402 hours compared to 321 hours.

Table A.4 presents the summary statistics for the load-weighted average LMP during constrained hours in 2000 and 2001. During constrained hours, the average load-weighted LMP in 2001 was about 24% higher than in 2000, the median load-weighted LMP in 2001 was about 13% higher,

Table A.4: 2000 and 2001 Load-Weighted Average LMPs During Constrained Hours ($/MWh)

	2000	2001	% Increase
Average LMP	35.35	43.79	23.9%
Median LMP	26.15	29.44	12.6%
Standard Deviation	29.98	72.00	140.2%

14 Source: The Ux Consulting Company, LLC (www.uxc.com).

15 For the purpose 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.

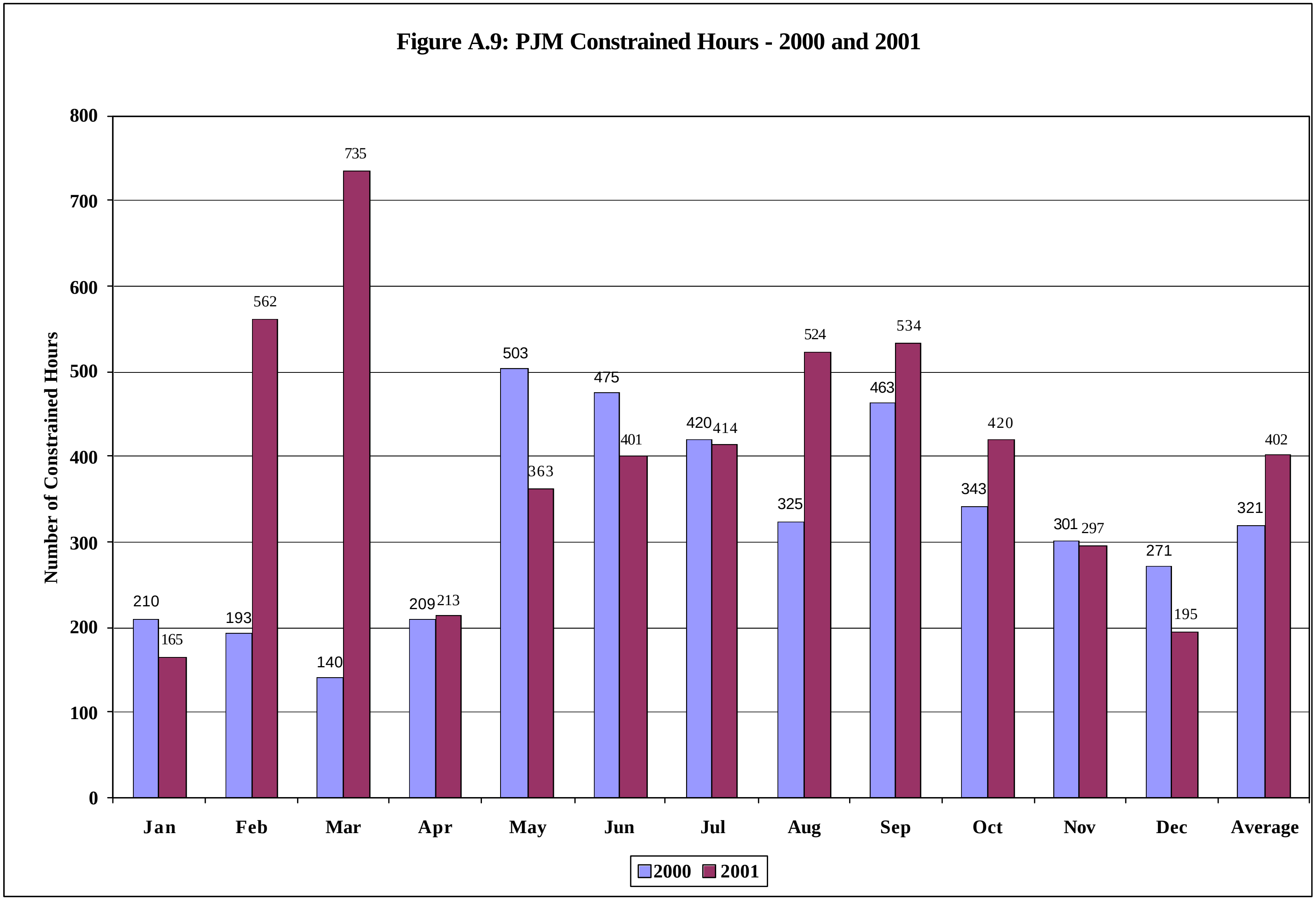


Figure A.9: PJM Constrained Hours - 2000 and 2001
Number of Constrained Hours
800
700
600
500
400
300
200
100
0
210
165
193
562
140
735
209
213
503
363
475
401
420
414
325
524
463
534
343
420
301
297
271
195
321
402
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Average
2000
2001

and the dispersion of LMPs about the average, as shown by the standard deviation, was about 140% higher than in 2000.

Table A.5 provides a comparison of load-weighted average LMPs during constrained and unconstrained hours for the two years. In 2001, average load-weighted LMP during constrained hours was 66% higher than average load-weighted LMP during unconstrained hours. The comparable numbers for 2000 are 33% and 47%, respectively.

Table A.5: Load-Weighted LMPs During Constrained and Unconstrained Hours ($/MWh)

	2000			2001		
	Unconstrained Hours	**Constrained Hours**	**Percent Difference**	**Unconstrained Hours**	**Constrained Hours**	**Percent Difference**
Average LMP	26.59	35.35	32.9%	26.40	43.79	65.9%
Median LMP	17.84	26.15	46.6%	19.53	29.44	50.7%
Standard Deviation	26.19	29.98	14.5%	19.12	72.00	276.6

Day-Ahead and Real-Time Prices

As noted earlier, real-time prices are slightly lower than day-ahead prices for most hours, while real-time prices reach higher overall levels. This pattern of price distribution can be seen in Figures A.4 and A.10. The figures show the frequency distribution by hours for the two markets. In the real-time market the most frequently occurring price interval is $10/MWh to $20/MWh, 36% of the hours. The most frequently occurring price interval in the day-ahead market is $20/MWh to $30/MWh, 31% of the hours. In the real-time market, prices are less than $20/MWh for 39% of the hours, while prices are less than $20/MWh in the day-ahead market for 27% of the hours. Cumulatively, prices are less than $30/MWh for 66% of the hours in the real-time market, 56% in the day-ahead; less than $40/MWh for 79% in the real-time market, 76% in the day-ahead market. At less than $50/MWh the real-time and day-ahead markets have about the same cumulative percent of 87%. In the real-time market, prices were above $150/MWh for 60 hours (0.6% of the hours), reaching a high for the year of $932/MWh also on August 9. In the day-ahead market, prices were above $150/MWh for 44 hours (0.5% of the hours), reaching a high for the year of $701/MWh on August 9. Figure A.11 shows how the daily average real-time and day-ahead LMPs compared over the year.

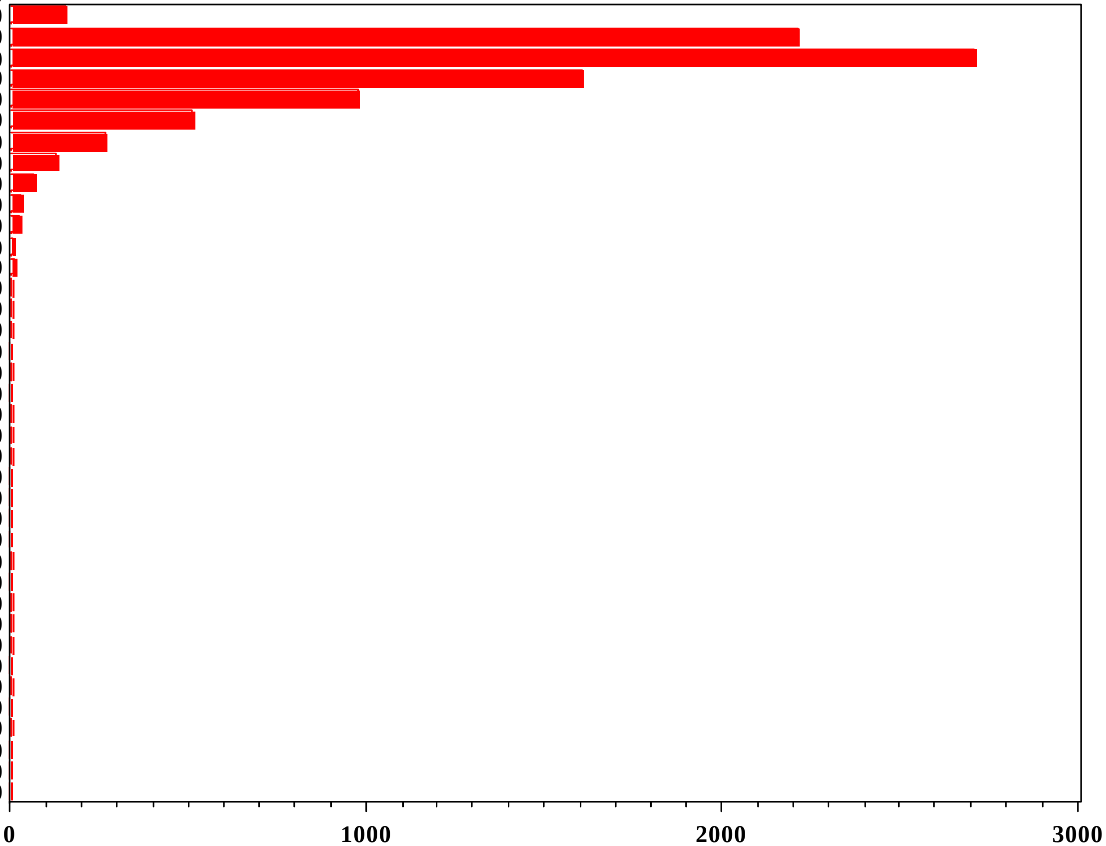
Peak and Off-Peak LMPs

Table A.6 shows the average LMPs during the off-peak and peak periods for the day-ahead and real-time markets. Day-ahead and real-time peak average LMPs were about twice as high as the corresponding off-peak average LMPs. The real-time peak average LMP was 1.6% higher than the day-ahead peak average LMP. The median LMPs during the peak hours were 75% and 71%

Figure A.10

Frequency Distribution by Hours of Day Ahead Market LMPs

2001



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	155	155	1.77	1.77
$10 to $20	2213	2368	25.26	27.03
$20 to $30	2710	5078	30.94	57.97
$30 to $40	1607	6685	18.34	76.31
$40 to $50	977	7662	11.15	87.47
$50 to $60	514	8176	5.87	93.33
$60 to $70	266	8442	3.04	96.37
$70 to $80	130	8572	1.48	97.85
$80 to $90	64	8636	0.73	98.58
$90 to $100	31	8667	0.35	98.94
$100 to $110	24	8691	0.27	99.21
$110 to $120	9	8700	0.10	99.32
$120 to $130	12	8712	0.14	99.45
$130 to $140	2	8714	0.02	99.47
$140 to $150	2	8716	0.02	99.50
$150 to $160	3	8719	0.03	99.53
$160 to $170	1	8720	0.01	99.54
$170 to $180	5	8725	0.06	99.60
$190 to $200	1	8726	0.01	99.61
$240 to $250	3	8729	0.03	99.65
$250 to $260	2	8731	0.02	99.67
$290 to $300	3	8734	0.03	99.70
$300 to $310	1	8735	0.01	99.71
$310 to $320	1	8736	0.01	99.73
$320 to $330	1	8737	0.01	99.74
$340 to $350	1	8738	0.01	99.75
$350 to $360	2	8740	0.02	99.77
$380 to $390	1	8741	0.01	99.78
$400 to $410	5	8746	0.06	99.84
$450 to $460	2	8748	0.02	99.86
$470 to $480	2	8750	0.02	99.89
$490 to $500	1	8751	0.01	99.90
$500 to $510	2	8753	0.02	99.92
$510 to $520	1	8754	0.01	99.93
$550 to $560	3	8757	0.03	99.97
$650 to $660	1	8758	0.01	99.98
$690 to $700	1	8759	0.01	99.99
$700 to $710	1	8760	0.01	100.00

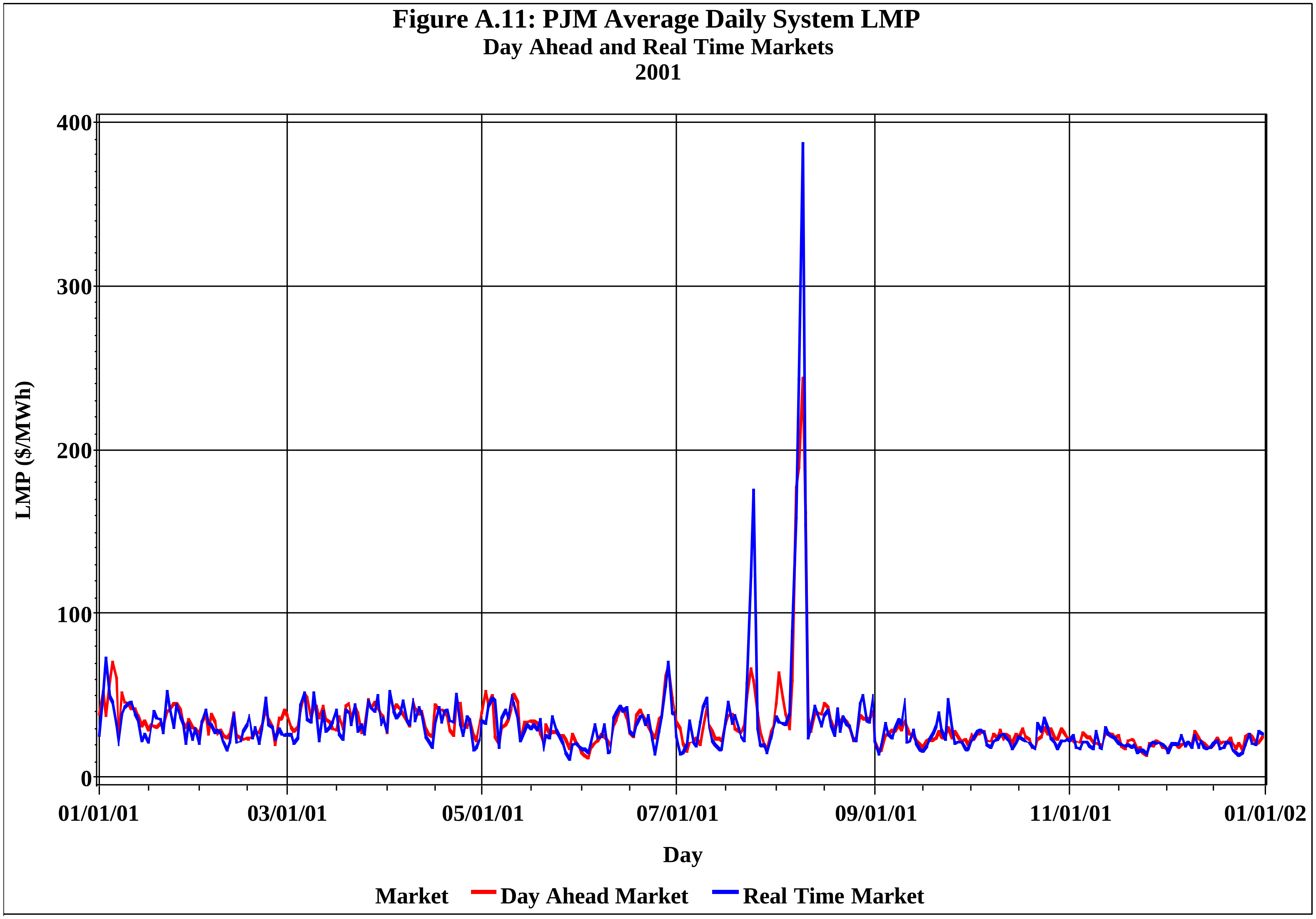


Figure A.11: PJM Average Daily System LMP
Day Ahead and Real Time Markets
2001
LMP ($/MWh)
400
300
200
100
0
01/01/01
03/01/01
05/01/01
07/01/01
09/01/01
11/01/01
01/01/02
Day
Market
Day Ahead Market
Real Time Market

higher in the day-ahead and real-time markets, respectively, than the off-peak median LMPs. The day-ahead median LMP was also 13% higher than the real-time median LMP. Since the mean lies above the median in both markets, both markets show a positive skewness. However, the mean is proportionately higher than the median in the real-time market than in the day-ahead market, during both peak and off- peak periods (39% and 21% compared to 21% and 16%, respectively) reflecting the larger positive skewness in the real-time market. During peak hours, the standard deviation in the real-time market is about 55% higher than in the day-ahead market, while it is 13% higher during the off-peak hours.

Figures A.12 and A.13 show the difference between real-time and day-ahead LMPs in 2001 during the peak and off peak hours, respectively. The average difference in LMP during the peak hours was only $0.68/MWh (real-time LMP higher than day-ahead LMP), while during off-peak hours the average difference between the two markets was -$1.23/MWh (real-time LMP less than day-ahead LMP). The figures show that there was more variability in the price differences during the peak than the off-peak hours. However, both figures show that the difference in the LMP between real-time and day-ahead decreased over the course of the year.

Table A.6: 2001 Off-Peak and Peak LMPs ($/MWh)

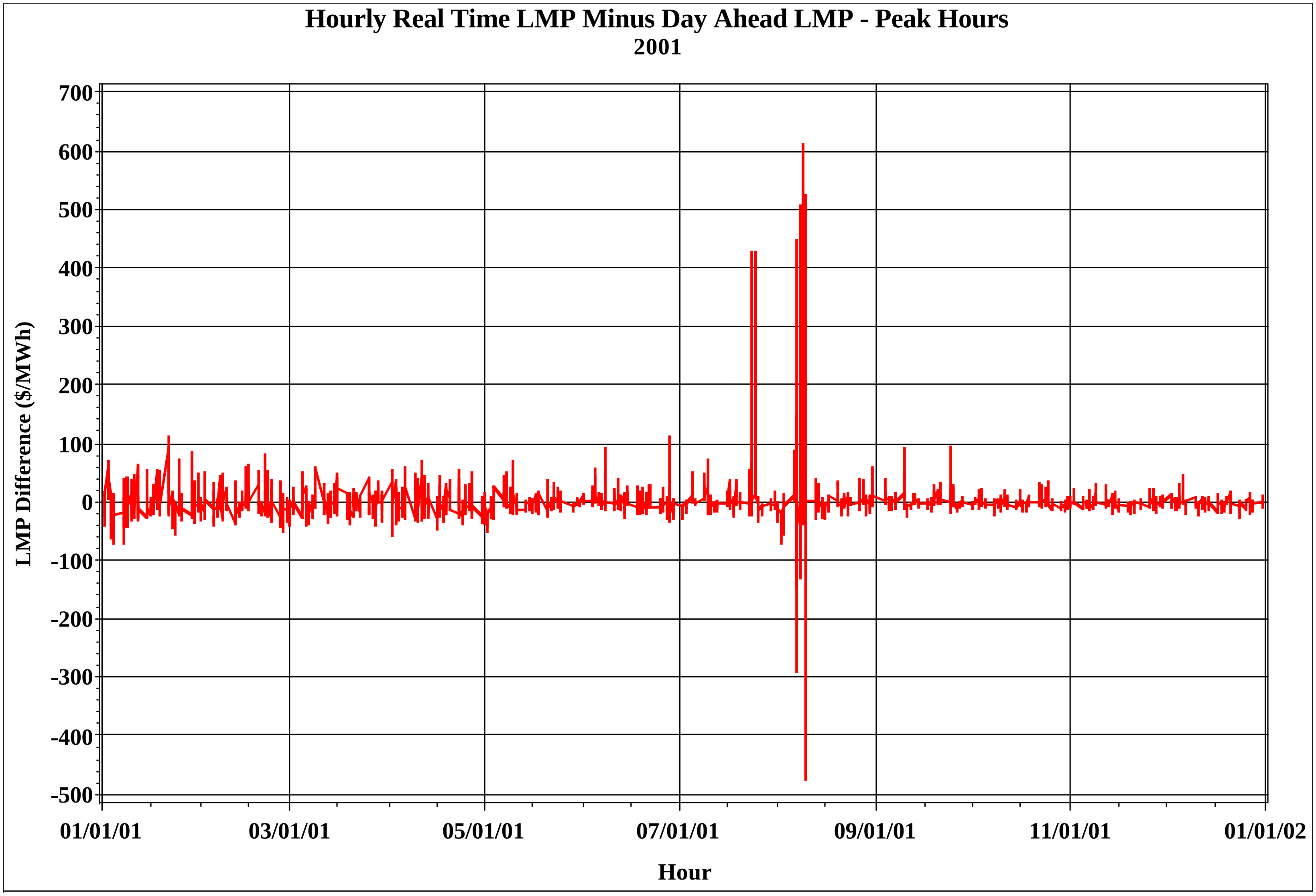
	Day-Ahead			Real-Time			Percent Change Day-Ahead to Real-Time	
	Off-Peak	**Peak**	**Peak/ Off-Peak**	**Off-Peak**	**Peak**	**Peak/ Off-Peak**	**Off-Peak**	**Peak**
Average LMP	23.65	43.19	1.83	22.37	43.86	1.96	-5.4%	1.6%
Median LMP	20.40	35.85	1.76	18.48	31.67	1.71	-9.4%	-11.7%
Standard Deviation	11.61	40.36	3.48	13.11	62.53	4.77	12.9%	54.9%

LMPs During Constrained Hours – Day-Ahead and Real-Time Markets[16]

Figure A.14 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 2001. Overall, there were 4,823 constrained hours in the real-time market and 7,337 constrained hours in the day-ahead market, 52% more. Figure A.14 shows that in every month of 2001 the number of constrained hours in the day-ahead market exceeded those in the real-time market.

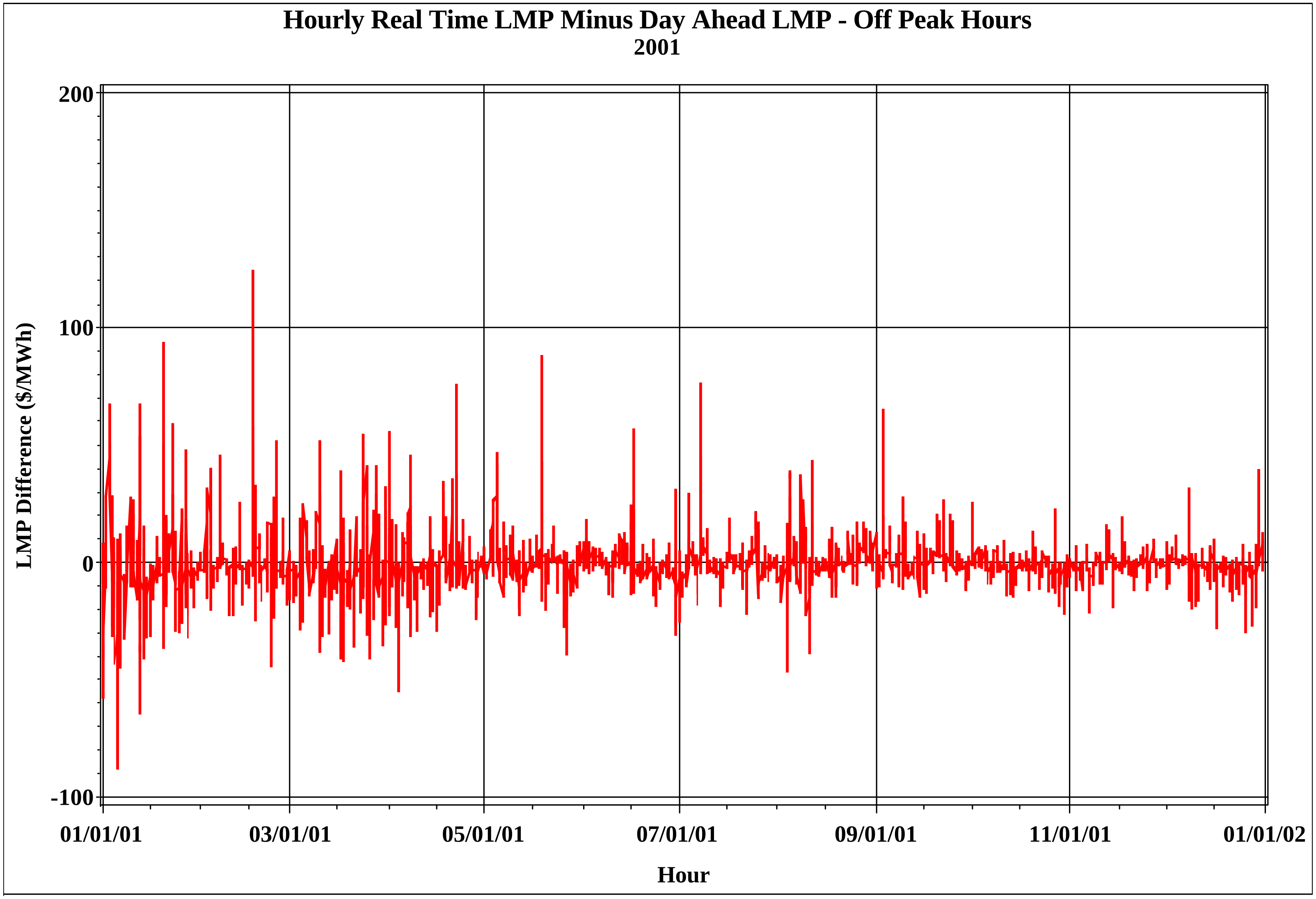
16 For the purpose of this discussion, a constrained hour is defined as one in which the difference in LMP between at least two buses in that hour is greater than $1.00.

Figure A.12



Hourly Real Time LMP Minus Day Ahead LMP - Peak Hours
2001
700
600
500
400
300
200
100
0
-100
-200
-300
-400
-500
LMP Difference ($/MWh)
01/01/01
03/01/01
05/01/01
07/01/01
09/01/01
11/01/01
01/01/02
Hour

Figure A.13


Hourly Real Time LMP Minus Day Ahead LMP - Off Peak Hours
2001
LMP Difference ($/MWh)
200
100
0
-100
01/01/01
03/01/01
05/01/01
07/01/01
09/01/01
11/01/01
01/01/02
Hour

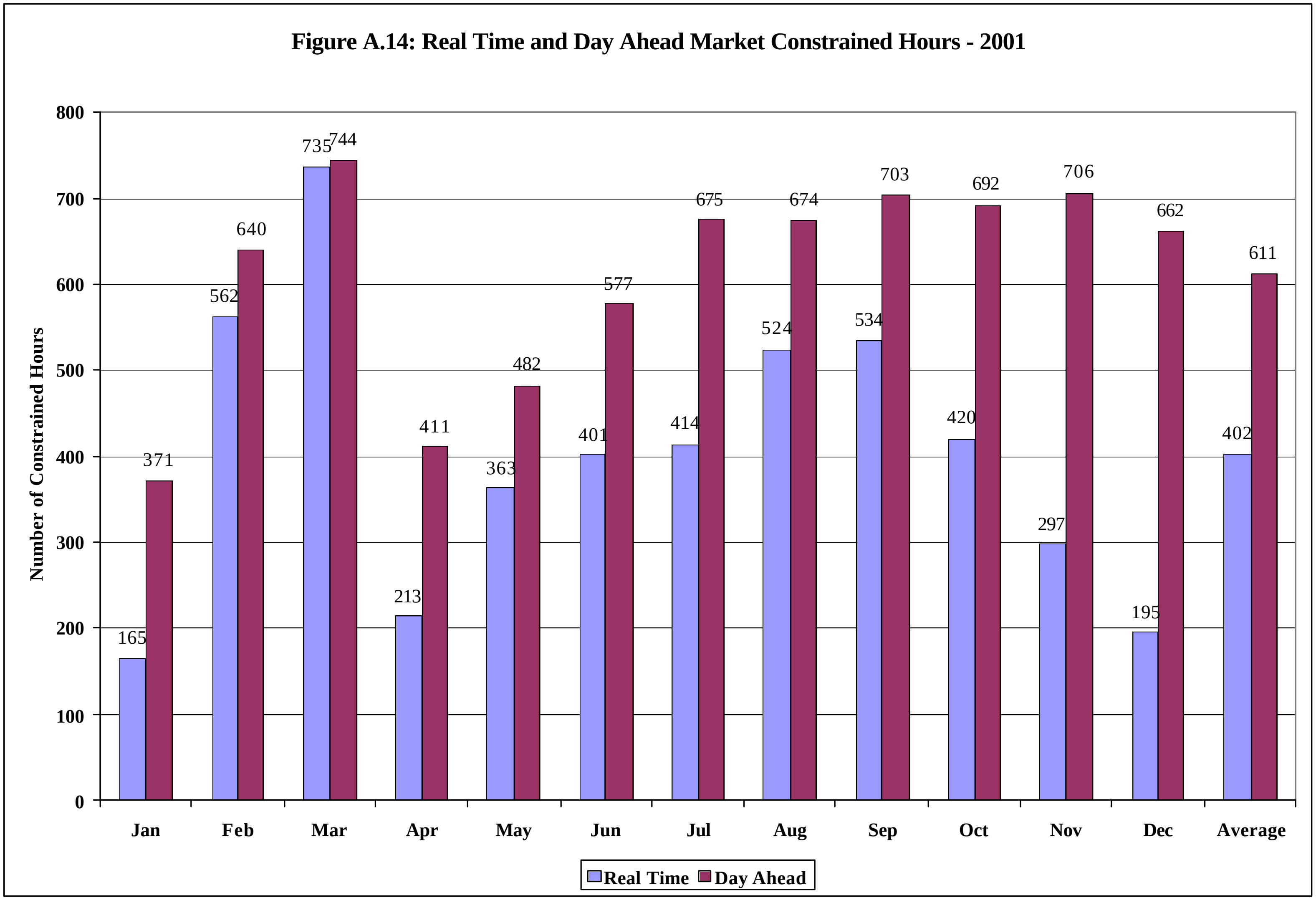


Figure A.14: Real Time and Day Ahead Market Constrained Hours - 2001
Number of Constrained Hours
800
700
600
500
400
300
200
100
0
165
371
562
640
735
744
213
411
363
482
401
577
414
675
524
674
534
703
420
692
297
706
195
662
402
611
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Average
Real Time
Day Ahead

Table A.7 shows average LMPs during constrained and unconstrained hours in the day-ahead and real-time markets. In the day-ahead market, average LMP during constrained hours was 8% lower than average LMP during unconstrained hours. In the real-time market, average LMP during constrained hours was 58% higher than average LMP during unconstrained hours. Average LMP during constrained hours was about 20% higher in the real-time market than the day-ahead market. There was greater price dispersion in the day-ahead market during unconstrained hours than constrained hours, while the real-time market exhibits more price dispersion during constrained hours than unconstrained hours.

Table A.7: LMPs During Constrained and Unconstrained Hours ($/MWh)

	Day-Ahead			Real-Time		
	Unconstrained Hours	Constrained Hours	Percent Increase	Unconstrained Hours	Constrained Hours	Percent Increase
Average LMP	35.16	32.28	-8.2%	24.50	38.81	58.4%
Median LMP	23.13	27.48	18.8%	18.44	27.68	50.1%
Standard Deviation	55.96	22.28	-60.2%	17.64	57.77	227.5%

Contrasting Table A.7 and Table 7, average LMP in the day-ahead market during constrained hours was about 1% lower than the overall average LMP for the day-ahead market, while average LMP during unconstrained hours was about 7% higher. In the real-time market, average LMP during constrained hours was 20% higher than the overall average LMP for the real-time market, while average LMP during unconstrained hours was 24% lower.

CAPACITY CREDIT MARKET

Summary and Conclusions

Under PJM rules, each LSE has the obligation to own or acquire capacity resources greater than or equal to the peak load that it serves plus a reserve margin.[1] The PJM capacity credit market provides a mechanism to balance the supply and demand of capacity that is not met via the bilateral market or self supply. Sometimes referred to as the capacity market, the PJM capacity credit market is comprised of interval, daily, monthly and multi-monthly capacity credit markets. The capacity credit market provides a transparent, market based mechanism for new, 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. PJM's daily capacity credit market provides a mechanism to permit LSEs to match capacity resources with daily shifts in retail load while interval, monthly and multi-monthly capacity credit markets provide a mechanism that matches longer term capacity obligations with capacity resources that are available.

The MMU has analyzed key measures of capacity credit market structure and performance for 2001, including prices, concentration and outage rate performance. The MMU concludes that there was a significant exercise of market power in 2001, that rule changes implemented by PJM addressed the immediate causes of that market power, that the PJM capacity credit market was reasonably competitive later in 2001, but that market power remains a serious concern given the extreme inelasticity of demand and the high levels of concentration in the capacity credit markets.

In January 2001, the MMU determined that there was a market power issue in the PJM daily capacity credit markets. In response to the observed behavior, the MMU proposed a change to the methodology used to allocate capacity deficiency revenues. The existing methodology allocated deficiency revenues solely to holders of unsold capacity resources. The MMU concluded that, under the specific market conditions in place during the first quarter of 2001, this methodology encouraged holders of unsold capacity to offer it for sale at a price greater than or equal to the Capacity Deficiency Rate (CDR) of $177.30 per MW-day. This conduct, in turn, caused market participants short of capacity either to be deficient (and pay the CDR, which then would be distributed to the withholder of the unsold capacity resources) or to purchase the capacity credits at a price equal to the CDR. The MMU's proposed rule change was to revise the methodology for the distribution of capacity deficiency revenues to holders of unsold capacity resources so as to provide the higher of market value or an allocation which included all LSEs that had met their obligations.

Based on the MMU findings, PJM filed to modify the rules governing the allocation of capacity deficiency payments. The modified rules became effective on June 1, 2001. The result has been substantially to remove the incentive to withhold capacity in order to receive CDR revenues.

The State of the Market Reports for 1999 and for 2000 recommended modifications to the capacity credit market rules to better align market incentives with PJM's reliability requirements while limiting the exercise of market power. In particular, the Reports recommended that the

[1] Capacity credit market terms are defined at the end of this section.

capacity credit market rules should be modified to require that all LSEs meet their obligation to serve load on an annual or semiannual basis. Based on these recommendations, PJM filed in 2001 to implement an interval market which gives LSEs an incentive to meet their obligation to serve load on an interval basis and gives capacity owners a corresponding incentive to sell capacity on an interval basis. The new RAA rules define three seasonal intervals. These changes became effective July 1, 2001. The result of the new rules has been an improved alignment between market incentives and system reliability requirements, as well as a reduction of incentives to exercise market power in the daily capacity credit markets.

Prices in the daily capacity credit market fell after the first quarter of the year and prices in the longer-term credit markets fell in the last quarter of the year, in both cases to levels closer to competitive levels. Concentration levels were high in both daily and longer-term capacity credit markets. While concentration levels declined somewhat in the latter part of the year they remained high. Unit outage rate performance continued to improve in 2001, consistent with the incentives provided by the capacity market.

Based on the structural conditions in the capacity credit markets including high levels of concentration and extremely inelastic demand, the MMU recommends that explicit market power mitigation rules be part of capacity market rules for the future.

A system of capacity obligations is required in order to ensure reliability and, despite its flaws, a capacity market, in some form, is required in order to permit the sale and purchase of capacity credits as load shifts among retail competitors. It is important to recognize that during the period of record high demands for energy in August 2001, the PJM system of capacity obligations, implemented in part via the capacity credit markets, functioned effectively and helped ensure that energy was available to meet those demands.

The design of the PJM West capacity market was approved during 2001, with implementation scheduled for 2002. The PJM West capacity market is based on an available capacity structure, focused on the short-term deliverability of energy in real time, rather than the installed capacity structure used in PJM. The MMU is concerned about the existence of two interacting capacity markets within PJM with different rules and different incentives and the associated potential for gaming. The MMU will carefully monitor these markets as they evolve. The MMU recommends that PJM implement a single capacity market design across all parts of PJM.

Market Fundamentals

PJM and its members have long relied upon capacity obligations as one of the methods to ensure reliability. Prior to the advent of retail restructuring, the original PJM members determined their loads and their related capacity obligations on an annual basis. When combined with state regulatory requirements to construct plants and incentives to maintain adequate capacity, the system of PJM capacity obligations resulted in a reliable pool, with the cost of capacity obligations borne equitably by members and their loads and with capacity and energy adequate to serve load.

Capacity obligations continue to play a critical role in maintaining reliability and contributing to the effective, competitive operation of the PJM energy market. Adequate capacity resources, as defined by the PJM Operating Agreement (OA) and Reliability Assurance Agreement Among Load Serving Entities in the PJM Control Area (RAA) help ensure that energy will be available on even the highest load days.

On January 1, 1999, in response to the requirements of retail restructuring, PJM introduced a transparent, open, PJM-run market in capacity credits.[2] New retail market entrants needed a way to acquire capacity credits to meet obligations associated with load gained through the competitive process and the existing utilities needed a way to sell capacity credits no longer needed if load was lost to new competitors. The PJM capacity credit market is the mechanism that balances the supply and demand for capacity credits that is not met via the bilateral market or via self-supply. The PJM capacity credit market provides another mechanism to exchange capacity credits among market participants as obligations change and as capacity available for sale varies. It is intended to provide a transparent market in which new competitors can buy capacity, new and existing generators can sell capacity and all competitors can buy and sell capacity based on need.

PJM's RAA states that 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."[3]

Under the RAA, each LSE must own or purchase capacity resources greater than or equal to the load that it serves plus a reserve margin. To cover their obligations, LSEs may own or purchase unit-specific generating capacity that meets the PJM criteria to be a capacity resource or purchase capacity credits. If an LSE's capacity resources are less than its obligation, the LSE is deficient. Deficient LSEs pay an interval penalty equal to the Capacity Deficiency Rate (CDR), which was $177.30/MW-day, times the number of days in an interval.[4] If an LSE is short as a result of a short-term increase in load the LSE pays the daily penalty until the end of the month.

Capacity resources may be purchased in three different ways which collectively comprise the capacity market:

- On a bilateral basis from a source internal to the PJM control area. Internal bilateral transactions 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, which is defined in terms of unforced capacity and measured in MW.
- From the PJM daily, monthly, multi-monthly or interval capacity credit markets. These markets, administered by PJM for terms of a day, a month, or multiple months, facilitate the exchange of capacity credits.

2 The first capacity markets were run in late 1998 with effective dates starting January 1, 1999.

3 Reliability Assurance Agreement Among Load Serving Entities in the PJM Control Area, revised March 21, 2000 ("RAA"), Article 2—Purpose, page 8.

4 The CDR is a function both of the annual carrying costs of a CT and the forced outage rate and thus may change annually. The CDR was changed to $176.83/MW-day effective June 1, 2001.

- From a generating unit external to the PJM control area. These capacity imports must meet PJM criteria including that the imports are from specific units and that the seller must have firm transmission from the identified units to the metered boundaries of the PJM Control Area.

Capacity resources are MW of net generation capacity which meet specified criteria and are committed to serving specific PJM loads, or MW of net generation capacity within the PJM Control Area which meet specified criteria. All capacity resources must pass tests regarding the capability of the generation to serve load and the deliverability of the energy to PJM load which requires adequate transmission service.[5]

The first link between capacity obligation and reliability is provided by the requirement that when generation owners sell capacity resources to PJM LSEs, they sell a recall right to the energy generated by their units and sold to entities outside PJM. This recall 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 the actual delivery of energy when it is needed. Thus, the energy from all capacity resources can be called upon by PJM in order to serve load within the PJM area. When recalled, the energy supplier is paid the PJM energy market price.

A second link between capacity obligation and reliability is the requirement that owners of capacity resources offer the output of these resources into PJM's day-ahead energy market. When LSEs purchase capacity, they ensure that the resources will be available to provide energy on a daily basis and not solely in emergencies. Since day-ahead offers are financially binding, resource owners must provide the offered energy at the offered price. This energy must be provided either from the specific unit offered or, if that unit is unavailable, by purchasing the energy at the spot market price and reselling the energy at the offer price.

Finally, FTRs are available to load only if a specific capacity resource is identified as the source of the energy to that load. Ownership of capacity credits is not adequate. Since capacity credits are not unit specific, there is no associated ability to use a capacity credit as the basis for an FTR. The FTR requirement adds value to the decision to be a capacity resource because this requirement creates an incentive for loads to enter into bilateral arrangements with capacity owners for unit specific capacity where load exists and is otherwise unhedged against the risk of congestion. A related trading strategy has emerged in which a generation owner will trade unit specific capacity for capacity credits. The actual terms of such a transaction depend on the relative values of the two commodities. For example, unit-specific capacity may be more valuable to a purchaser because of the relative locations of that capacity and the purchaser's load and the value of the associated FTRs. The result could be that the purchaser would be willing to trade more than the equivalent amount of capacity credits for a MW of such capacity.

5 See RAA, Capacity Resources, page 2.

6 PJM Emergency procedures are defined in the PJM Manual for Emergency Operations.

The first two features of capacity resources clearly are essential to the definition of a capacity resource and contribute directly to the reliability of the system. The importance of the link between capacity resources and FTRs is less clear.

Market Dynamics

Procedures set forth in the RAA determine the total capacity obligation for PJM and thus the total demand for capacity credits. The RAA includes rules for allocating the 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 interval, multi-monthly, monthly or daily capacity credit markets. Demand for capacity credits in daily markets are the residual demand after capacity credits are purchased in monthly and multi-monthly markets or through bilateral transactions.

The supply of capacity credits in all the PJM capacity credit markets is a function of physical capacity in the PJM control area, prices in the PJM capacity market, capacity resource imports, the availability and price of transmission, prices in the PJM energy market and prices in external energy markets. The existence of physical capacity resources in the PJM control area has no necessary relationship to the supply of capacity in the PJM capacity markets, as capacity resources can be delisted, i.e. exported, from the PJM control area and imported from external control areas. It is the option to delist capacity resources, as well as the more limited ability to import capacity resources, which makes capacity supply in PJM a function of both capacity market prices and the spread between internal and external energy market prices.

Generation owners can be expected to sell capacity into the most profitable market. If the markets worked efficiently and generators faced only the choice between selling energy to external markets or selling capacity and energy to the PJM markets, the value of capacity would be defined by the difference between the external energy price and the internal energy price. The opportunity cost of selling both capacity and energy in the PJM markets would be defined by the external energy price. The difference between the external energy price and the internal energy price would be the marginal cost of capacity and thus the expected market price.

Opportunity cost is more complex than this simple case. In fact, generators can both remain capacity resources and sell energy to external energy markets. When generators do this, if the capacity markets worked efficiently, the PJM capacity price would be a function of the expected distribution of the difference between external and internal energy prices and the expected distribution and cost of PJM recalls of the external energy sales. The marginal cost and thus the expected price of capacity is a function of the difference between (a) the opportunity to delist and thus sell the energy from that capacity externally without risk of recall, and (b) the opportunity to receive capacity payments plus the opportunity to choose the most profitable mix of internal energy sales and external energy sales offset by the possibility that the external energy sales may be recalled. Thus, the expected difference in revenue between the choice to delist a unit and the choice to be a capacity resource, will range from zero (or less than zero) to the simple difference between the external price and the internal price. This difference is a function of the expected probability of recall and the expected distribution of the difference between external and internal energy prices. The higher the expected probability of recall, the lower the value of selling energy externally while remaining a capacity resource and thus the higher the opportunity cost of remaining a capacity resource.

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.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the 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 market is the additional revenue foregone from not selling into an external energy and/or capacity market.

Capacity Market Structure

Supply Side

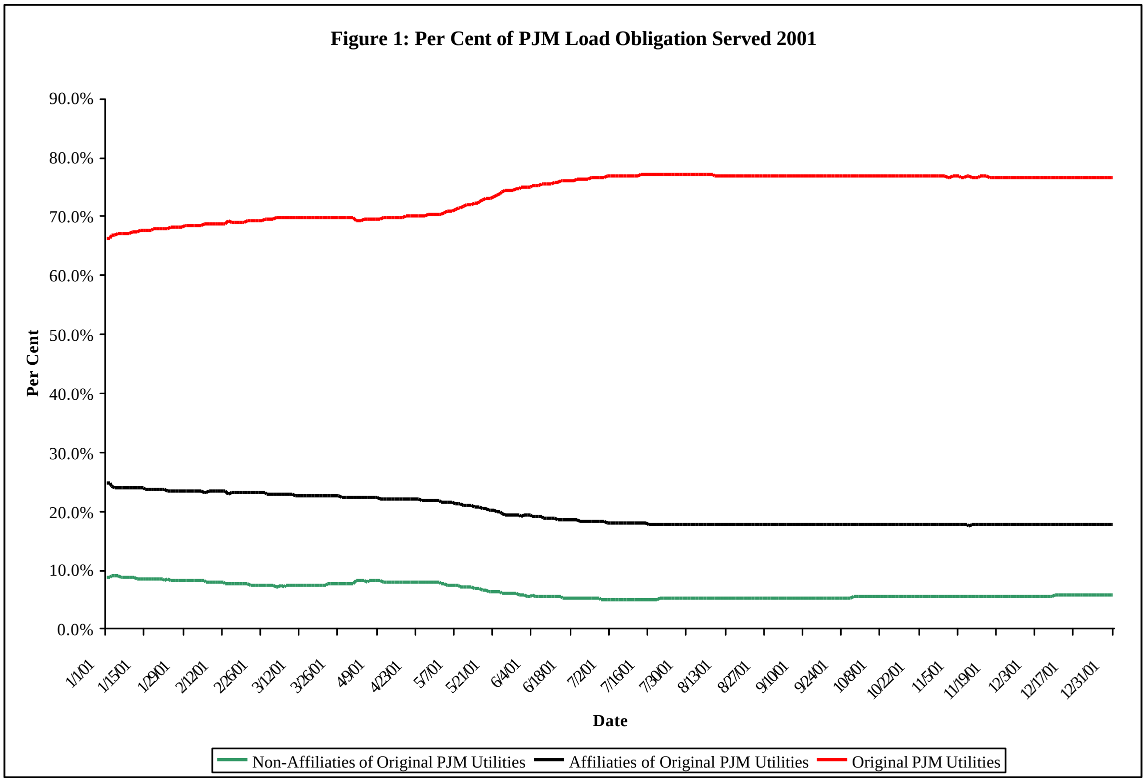
Concentration ratios are a summary measure of market shares, a key element of market structure. High concentration ratios mean that a small number of sellers dominate the market while low concentration ratios mean that a larger number of sellers share in market sales more equally. However, concentration measures must be used 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 geographical market areas. However, high aggregate market concentration ratios do indicate an increased potential for market participants to exercise market power.

The structural analysis indicates that overall, PJM capacity credit markets exhibit high levels of concentration. HHIs for the daily capacity credit markets averaged about 2700 during 2001, with a maximum of about 5500 and a minimum of about 1100. (Four firms with equal market shares would result in an HHI of 2500.) HHIs for monthly and multi-monthly capacity credit markets averaged about 3800, with a maximum of 10000 and a minimum of more than 1700.[7] (Three firms with equal market shares would result in an HHI of 3333.)

Demand Side

PJM electric utility companies served the majority of PJM load obligations in 2001, followed by affiliates of PJM electric utilities and non-affiliated companies, as shown in Figure 1. PJM electric utilities served an average of 74% of PJM load obligations in 2001, while their affiliates served 20% and non-affiliated companies served 6%. The share of PJM electric utilities generally increased over the year and ranged from 66% to 77%. The share of the affiliates of PJM electric utilities generally declined over the year and ranged from 18% to 25% while the share of non-affiliated companies also generally decreased over the year and ranged from 5% to 9%.

[7] See the Energy Section for a discussion of the HHI measure.



Reliance on PJM capacity credit markets also varied by sector during 2001, as shown in Table 1. PJM electric utilities relied on the PJM capacity credit markets for a weighted average of .6% of their load obligation during 2001. Affiliates of PJM electric utilities relied on the PJM capacity credit markets for a weighted average of –3.2% of their load obligations during 2001 while non-affiliated companies relied on the PJM capacity credit markets for a weighted average of 4.5% of their load obligations. The use of PJM capacity credit markets ranged from negative to positive during the year for each of these groups. The measure of reliance on the PJM capacity credit markets is the net of each group's purchases and sales of capacity credits in the PJM markets. This excludes self-supply and bilateral transactions. A negative number means that, as a group, sales of capacity credits in PJM markets exceeded purchases of capacity credits. For example, the load obligations of non-affiliated companies declined from April 1 to May 31. As load obligations declined, sales of capacity credits increased while purchases declined. The net impact was a negative share of load obligation served from the capacity credit market for the group during May. This reversed in June, as sales declined and purchases increased.

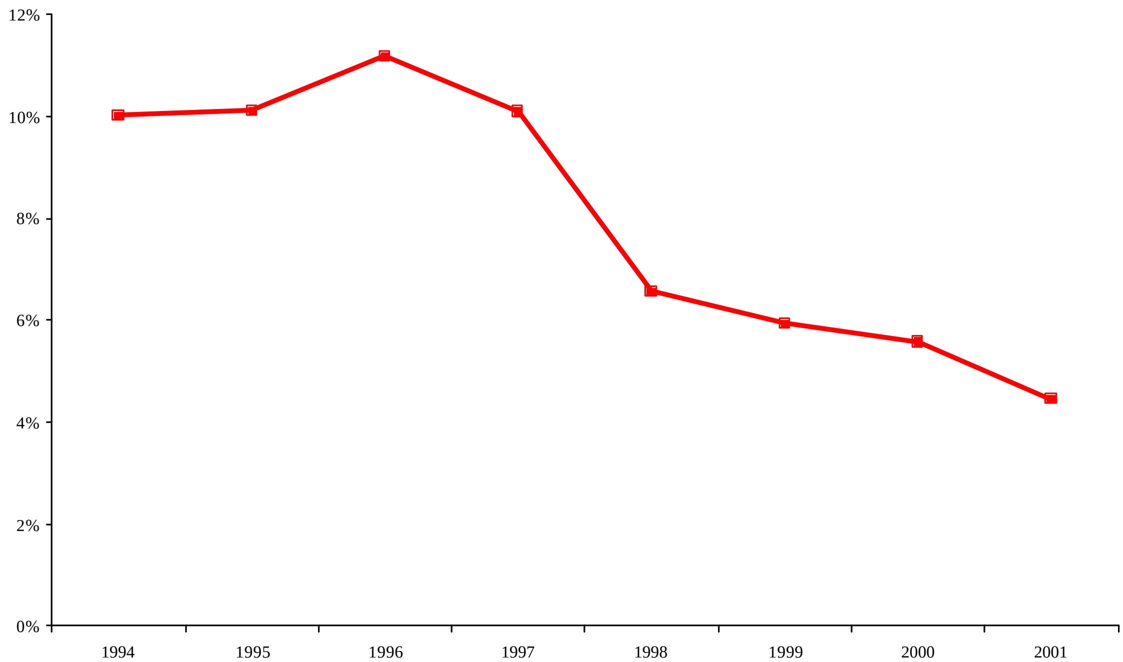
Table 1. Load Obligation Served by the PJM Capacity Credit Market			
Month	Original PJM Utilities	Affiliates of Original PJM Utilities	Non-Affiliates
Jan-01	0.7%	-2.1%	0.7%
Feb-01	1.3%	-6.0%	6.3%
Mar-01	0.9%	-4.7%	6.0%
Apr-01	2.9%	-12.1%	8.0%
May-01	2.8%	-7.0%	-8.8%
Jun-01	-0.7%	-4.5%	26.0%
Jul-01	1.4%	0.5%	2.5%
Aug-01	-0.4%	-0.3%	6.4%
Sep-01	-0.3%	0.6%	2.0%
Oct-01	-0.2%	-0.8%	5.4%
Nov-01	-0.3%	-0.1%	4.7%
Dec-01	-0.2%	1.2%	-1.6%
For The Year 2001	0.6%	-3.2%	4.5%

Given the basic features of capacity market structure including high levels of concentration, the relatively small number of non-affiliated 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.

Capacity Availability (Outage Rates)

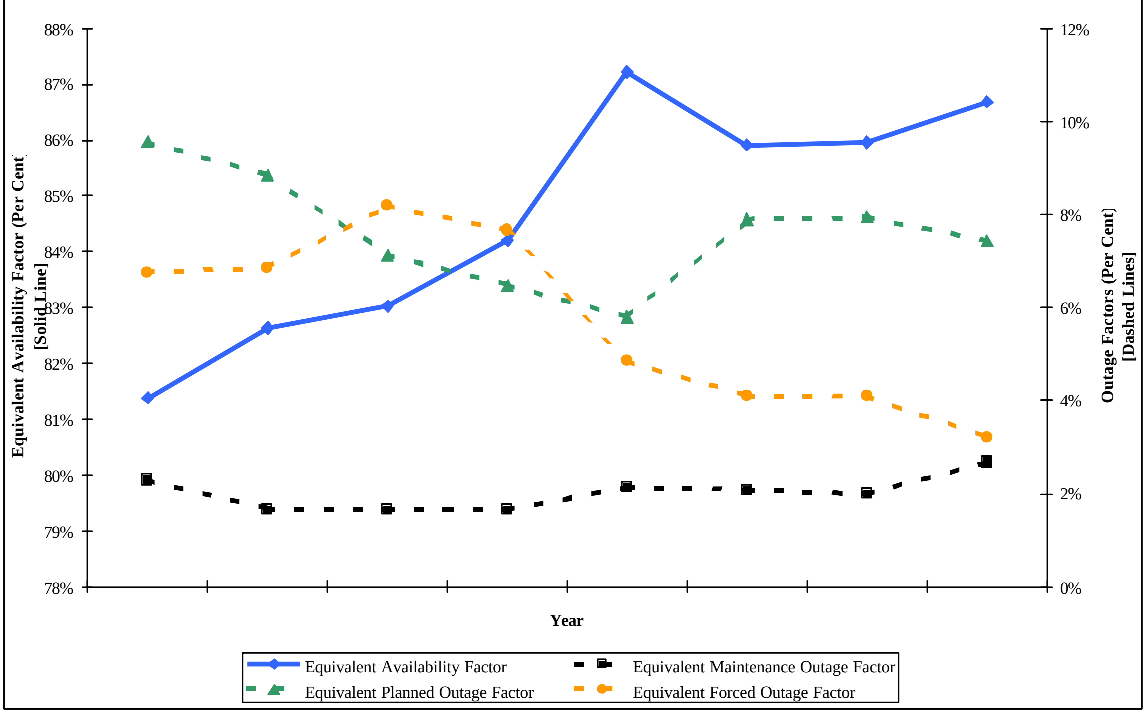
The ICAP market creates an incentive to minimize forced outages because the amount of capacity resources available from a specific unit is directly related to the forced outage rate of the unit. The existence of a competitive energy market also creates an incentive to minimize forced outages, as units must run when called upon in order to receive revenues. PJM's equivalent demand forced outage rate has trended down since 1996. The equivalent demand forced outage rate is a statistical measure of the probability that a unit will fail, either partially or totally, to perform when needed. The equivalent demand forced outage rate (EFORd) was 4.5% in 2001. Figure 2 shows the equivalent demand forced outage rates.

Figure 2: Equivalent Demand Forced Outage Rate
1994 - 2001



Certain outage statistics are calculated by reference to the total hours in the year, rather than statistical probabilities. Figure 3 shows these performance measures for PJM units. The Equivalent Availability Factor, for example, represents the proportion of hours in the year that a unit was available to generate, in effect, at full capacity. The sum of the Equivalent Availability Factor, the Equivalent Maintenance Outage Factor, the Equivalent Planned Outage Factor and the Equivalent Forced Outage Factor equals 100%. The PJM aggregate Equivalent Availability Factor was 86.7% in 2001.

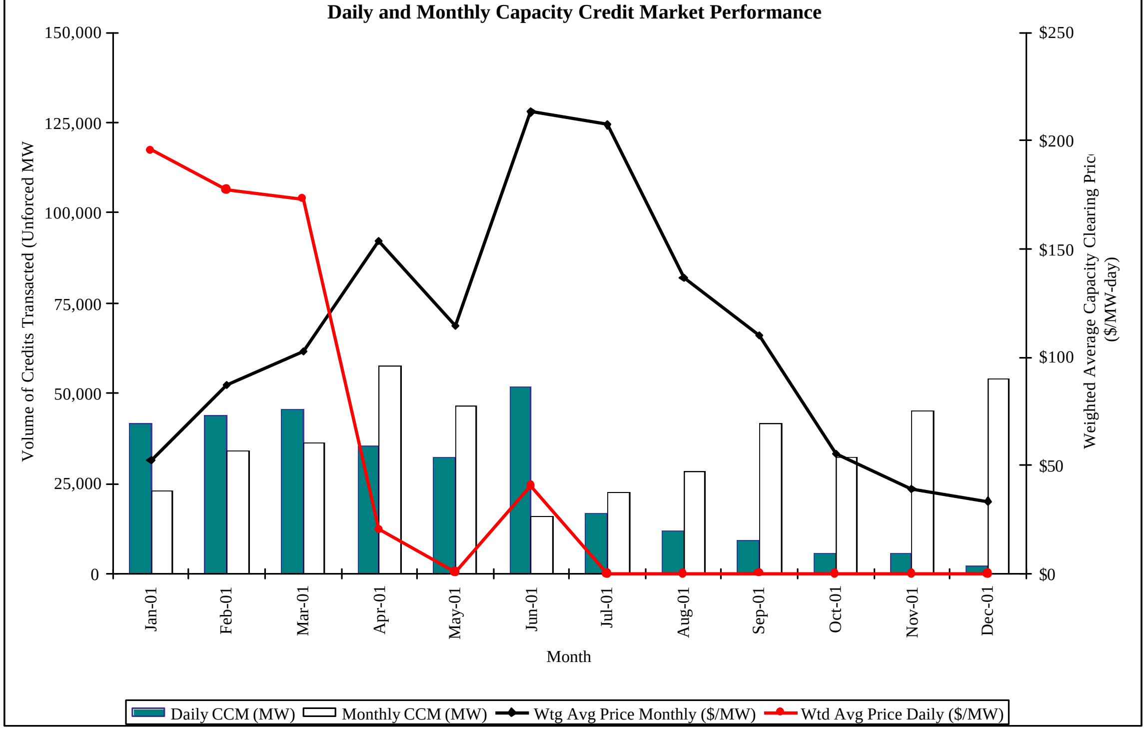
Figure 3: Equivalent Outage Factors and Equivalent Availability Factor 1994-2001



Capacity Credit Market Prices

Capacity credit market prices and volumes for the entire year are shown in Figure 4 below and in Table 2. The volume-weighted average price for 2001 was $100.43/MW-day in the monthly and multi-monthly capacity credit markets and $87.98/MW-day in daily capacity credit markets. The volume-weighted average of all capacity credit markets was $95.34/MW-day.[8] Prices in the capacity credit markets in 2001 were significantly higher overall than in 2000 and 1999. Prices in both daily and monthly/multi-monthly markets peaked in the first half of the year and declined in the second half of the year. The volume-weighted average of all capacity credit markets was $52.86/MW-day in 1999 and $60.55 in 2000. Prices in the monthly and multi-monthly capacity credit markets were $70.66/MW-day in 1999 and $53.16 in 2000, while the daily capacity credit market price averaged $3.63/MW-day in 1999 and $69.39 in 2000.

Figure 4: January Through December 2001
Daily and Monthly Capacity Credit Market Performance



As explained below, capacity market prices in the first part of 2001 reflected the exercise of market power in the capacity credit market. The market power issue was addressed via the introduction of new rules governing the allocation of capacity deficiency payments. Prices in the daily capacity credit markets fell after the first quarter of the year and prices in the longer-term capacity credit markets fell in the last quarter, in both cases to levels closer to competitive levels.

8 The 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 2. PJM Capacity Credit Market, 2001						
Month/Year	Daily (MW)	Monthly and Multi-Monthly (MW)	Combined (MW)	Weighted Average Price Daily ($/MW)	Weighted Average Price Monthly and Multi-Monthly ($/MW)	Weighted Average Price Combined ($/MW)
Jan-01	41,498	22,859	64,358	195.36	52.51	144.62
Feb-01	43,759	34,076	77,835	177.30	87.35	137.92
Mar-01	45,597	36,385	81,982	172.96	102.62	141.74
Apr-01	35,398	57,570	92,968	20.30	153.61	102.85
May-01	32,168	46,336	78,503	0.74	114.22	67.72
Jun-01	52,017	16,020	68,037	40.61	213.13	81.23
Jul-01	16,922	22,357	39,280	0.00	207.24	117.96
Aug-01	11,955	28,102	40,057	0.00	136.48	95.75
Sep-01	9,455	41,595	51,050	0.19	110.24	89.86
Oct-01	5,890	32,156	38,047	0.00	55.33	46.77
Nov-01	5,818	45,390	51,208	0.00	38.95	34.52
Dec-01	1,973	53,965	55,938	0.00	33.49	32.31
2001	302,451	436,811	739,262	87.98	100.43	95.34

Capacity Credit Markets in the First Quarter of 2001

In its report to the Pennsylvania Public Utility Commission (PaPUC) covering the PJM capacity credit markets from January through April 2001, the MMU concluded that a single entity, acting unilaterally, exercised undue market power in the PJM capacity credit markets during the first quarter of 2001.[9] The result was that the price in the capacity credit markets during this interval was higher than it would have been in a competitive market.

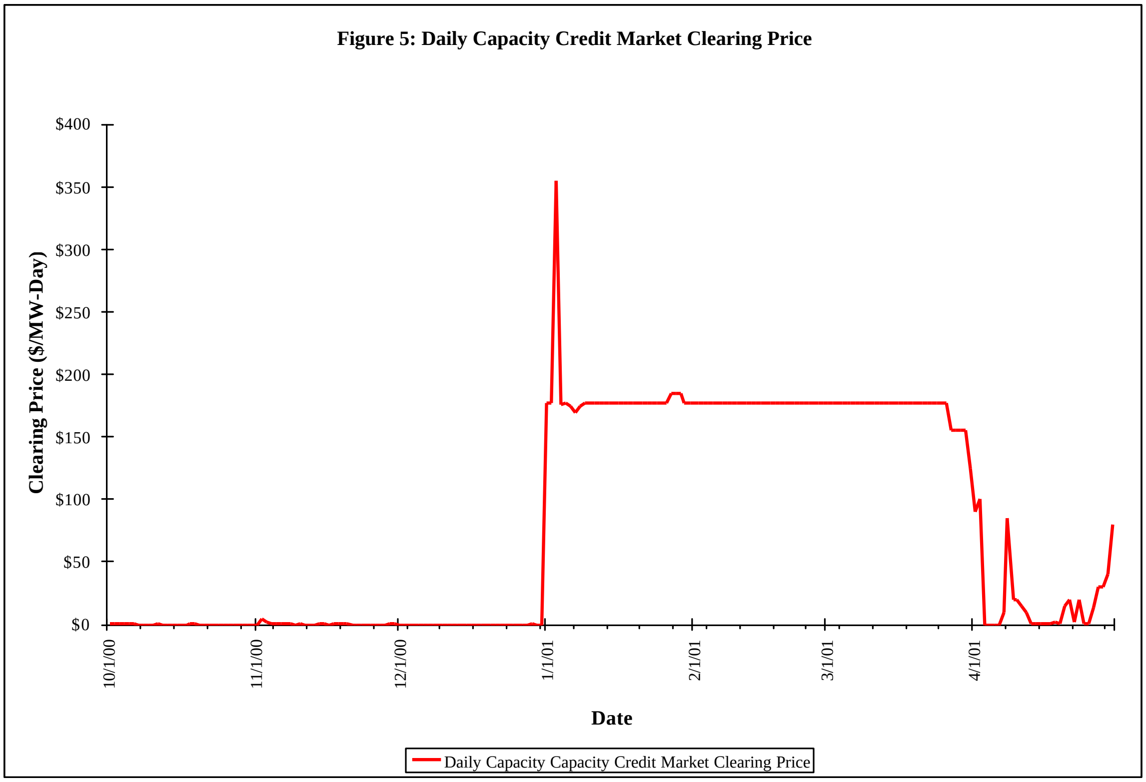
Market power is defined as the ability to increase the market price above the competitive level, that is, the price that would exist in a competitive market. The exercise of undue market power is thus an action taken which results in an increase of the market price above the competitive level. This standard is broader than the legal standard for antitrust enforcement.

A participant in the PJM daily capacity credit market raised the market price in the daily capacity credit market above the competitive level for a portion of the period from January 1 to April 30, 2001. While the rules of the capacity market did not explicitly prohibit this conduct, the behavior constituted the exercise of undue market power and was inconsistent with the intended consequences of the rules. The higher prices in the daily capacity credit market were the direct result of actions by a participant in the PJM capacity credit markets. (This participant will be referred to as Entity1 or E1.) In the absence of those actions, the prices in the daily capacity markets would have been lower.

Figure 5 shows the prices in the PJM daily capacity credit markets from October 1, 2000 to April 30, 2001. PJM daily capacity prices were approximately zero from October 1, 2000 to December 31, 2000, increased to about $177 on January 1 and 2, increased further to about $354 for one day, January 3, and then declined to $177 where they remained until late March when the price began to decline further, reaching $0 in early April. Prices reached $354/MW-day on January 3 as a result of the capacity market rules which provided that any deficient party must pay twice the CDR on a day when the overall market is deficient, or short, and which required the entry of mandatory bids at twice the CDR for any deficient party. The overall market was deficient on January 1, 2 and 3.

Prices in the PJM daily capacity credit markets averaged about $177/MW-day for the period from January 1 to March 31, 2001. (Figure 5.) While it is not a simple matter to define the competitive price for this period, it can be estimated within a reasonable range.

[9] By a letter dated April 12, 2001, the PaPUC requested information and set forth questions concerning the clearing prices for installed capacity credits in the capacity credit markets administered by PJM Interconnection, L.L.C. ("PJM"). The report was provided in November to permit the inclusion of detailed offer data which may only be made public by PJM six months after the fact under the Federal Energy Regulatory Commission ("FERC") Order approving the formation of the PJM Marketing Monitoring Unit ("MMU"). PJM Interconnection, L.L.C., 86 FERC ¶ 61,247, reh'g denied, 88 FERC ¶ 61,274 (1999).

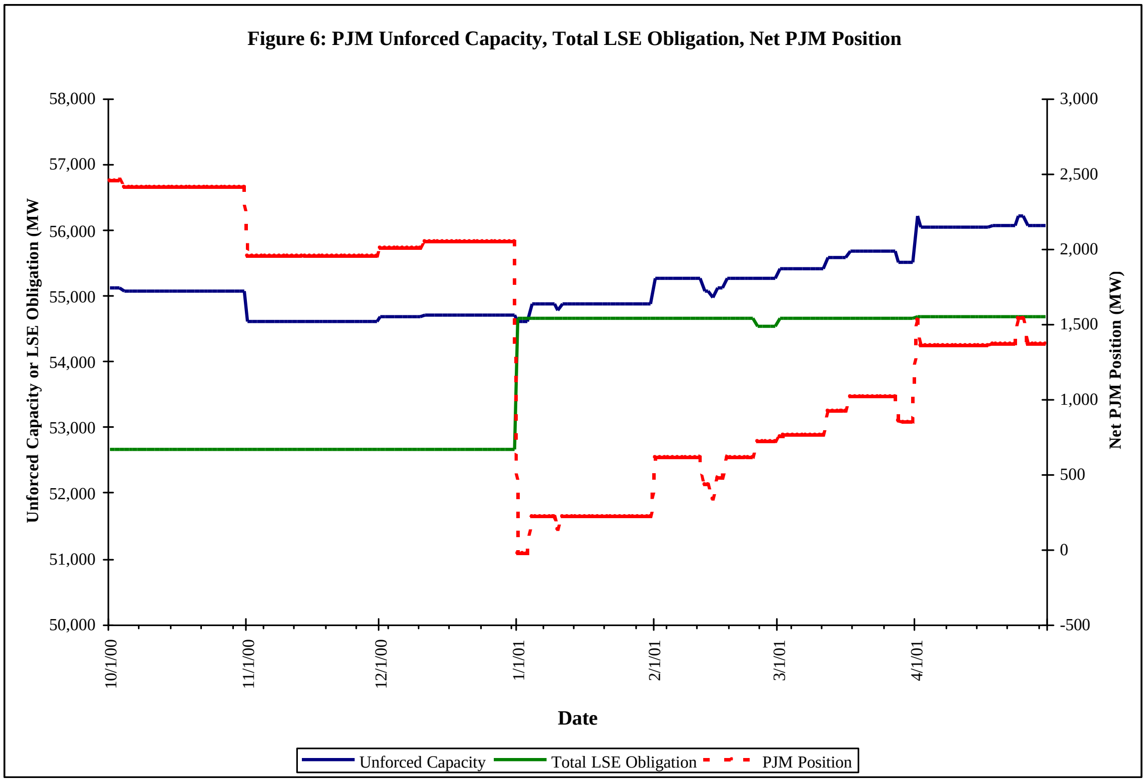


In general, high prices do not, by themselves, demonstrate the exercise of market power. For example, the MMU concluded that high prices in the PJM capacity credit market during the summer of 2000 reflected market fundamentals, not the exercise of market power.[10]

When the pool is capacity deficient, it can be plausibly argued that the competitive price is at least $177.30/MW-day and as high as two times the daily deficiency rate, or $354.60/MW-day, based on the RAA rules in existence at that time, which doubled the deficiency payment when the pool was short. This would not be the competitive price if the pool were deficient as the result of non-economic delisting. Non-economic delisting, or economic withholding, is delisting when such delisting is not profitable on a transaction-specific basis.

In the last quarter of 2000, the net PJM capacity position was approximately 2,000 MW long; the available supply of capacity exceeded the obligation to purchase capacity. (Figure 6.) However, the PJM capacity credit market was tighter (the excess of available supply over demand was smaller) after January 1, 2001 than it had been in the fourth quarter of 2000.

10 PJM Interconnection State of the Market Report 2000.



The reasons for the changed balance between supply and demand are straightforward. On the demand side, the capacity obligations of LSEs grew by nearly 2,000 MW or almost 4 percent on January 1. This increase was the result of the process by which capacity obligations are determined under the RAA. Capacity obligations are primarily a function of the weather adjusted peak load for the prior summer and become effective on January 1 of each year.[11]

On the supply side, the result of decisions by PJM generation owners to delist capacity, or to return delisted capacity in January, reduced the net supply of capacity by a small amount (37 MW) on January 1. (Figure 7.) On January 4, 246 MW of capacity, which had been delisted for the first three days of January, returned to the pool and the pool was capacity sufficient as a result. The pool remained capacity sufficient for the balance of the quarter.

In summary, PJM was capacity deficient (Figure 6) on January 1, 2 and 3, 2001 by about 30 MW. That is, on these three days there was slightly less capacity available for sale in the pool than the capacity purchase obligations of the LSEs in the pool. On subsequent days, the net PJM position was positive and grew steadily more positive through the end of April. In December 2000, the average net PJM position was about 2,000 MW, in January 2001 about 200 MW, in February about 600 MW, in March about 900 MW and in April about 1,400 MW.

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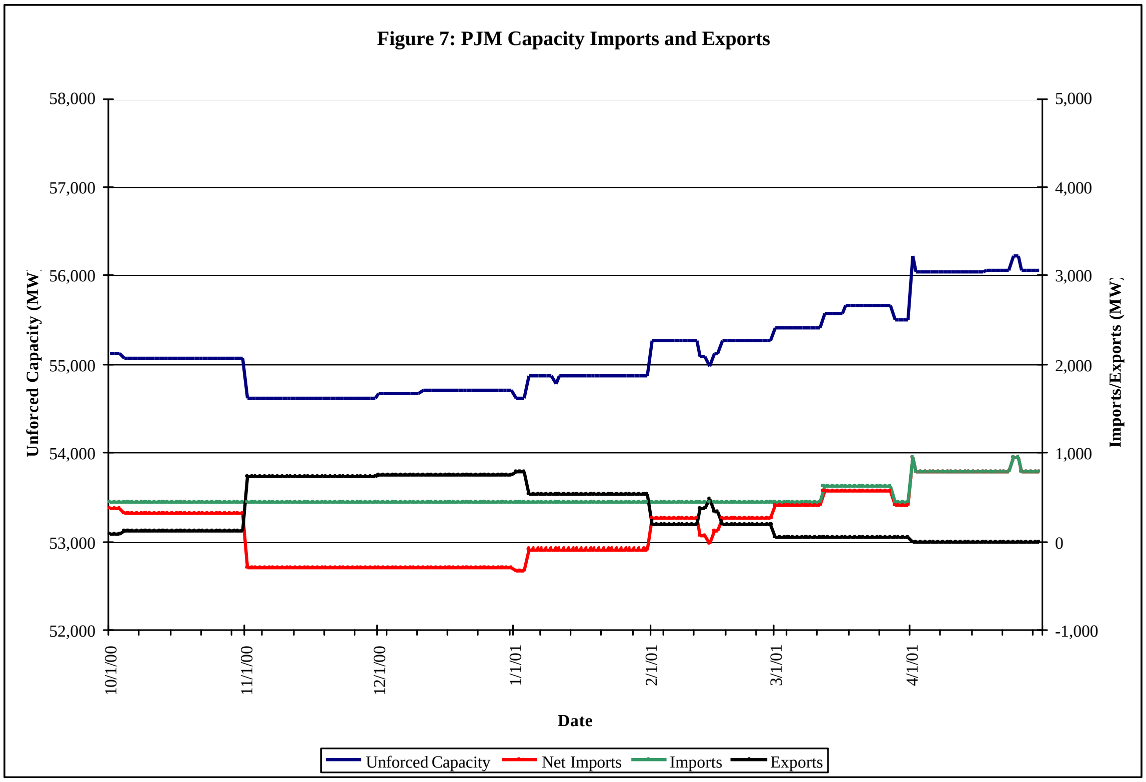
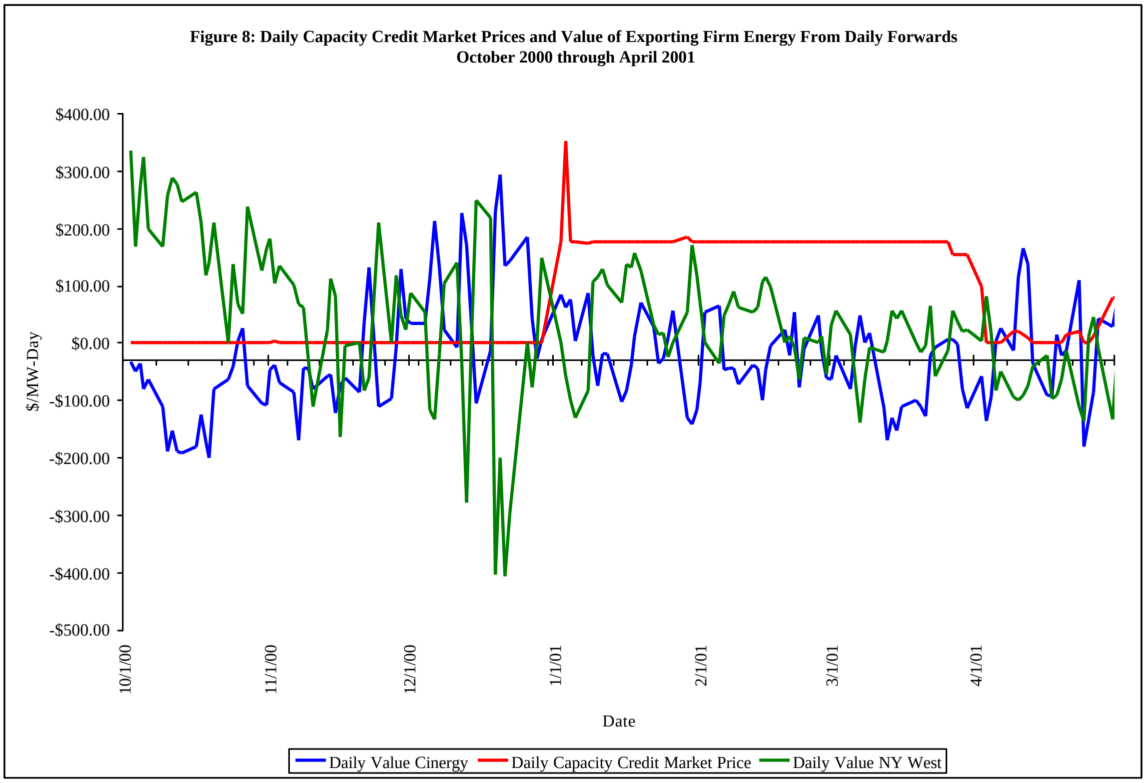
11 The January 2001 increase in capacity obligation had been made public by PJM in October 2000, so both capacity owners and LSEs were aware of the pending increase.



When the daily capacity credit market price is compared to the alternative opportunities available for selling the capacity of generating units, or the firm energy which the units can provide, it becomes clear that, based on the available data for the identified alternatives, the price in the PJM daily capacity credit markets exceeded the competitive level, for the period after January 3. The alternative to selling capacity and energy in the PJM market for the next day is to sell the firm energy output from the capacity resource to a purchaser outside PJM. The owner of capacity faces a range of alternatives including selling the firm energy forward for the next day or selling the firm energy for the balance of the month including the next day. Figure 8 shows the prices in the PJM daily capacity credit markets compared to the value of selling firm energy into Cinergy or N.Y. Zone A (West) for the next day. The value of selling daily firm energy outside PJM for the next day is calculated, in Figure 8, as the difference between the external daily forward price and the PJM daily forward price for the sixteen on peak hours reflected in the forward prices.

From January through the beginning of April, the price in the daily PJM capacity credit market exceeded the spread between the PJM West hub and both Cinergy and N.Y. Zone A, valued over 16 hours. In other words, the price of capacity credits in the daily market exceeded the additional value of selling firm energy from that capacity to the Cinergy hub or N.Y. West Zone A for the next day rather than selling energy to the PJM West hub and capacity to the PJM capacity credit market. This opportunity cost calculation is conservative in that it does not include any transmission costs or transaction costs and does not account for the fact that capacity can be sold in the PJM capacity market and, at the same time, the firm energy from that capacity can also be sold outside PJM, subject to the risk of recall, which was low during this period. This opportunity cost calculation does not include any value associated with the probability that there could be a spike in the differential between the external real time price and the internal real time price for the operating day. This probability was also relatively low during the period under review.

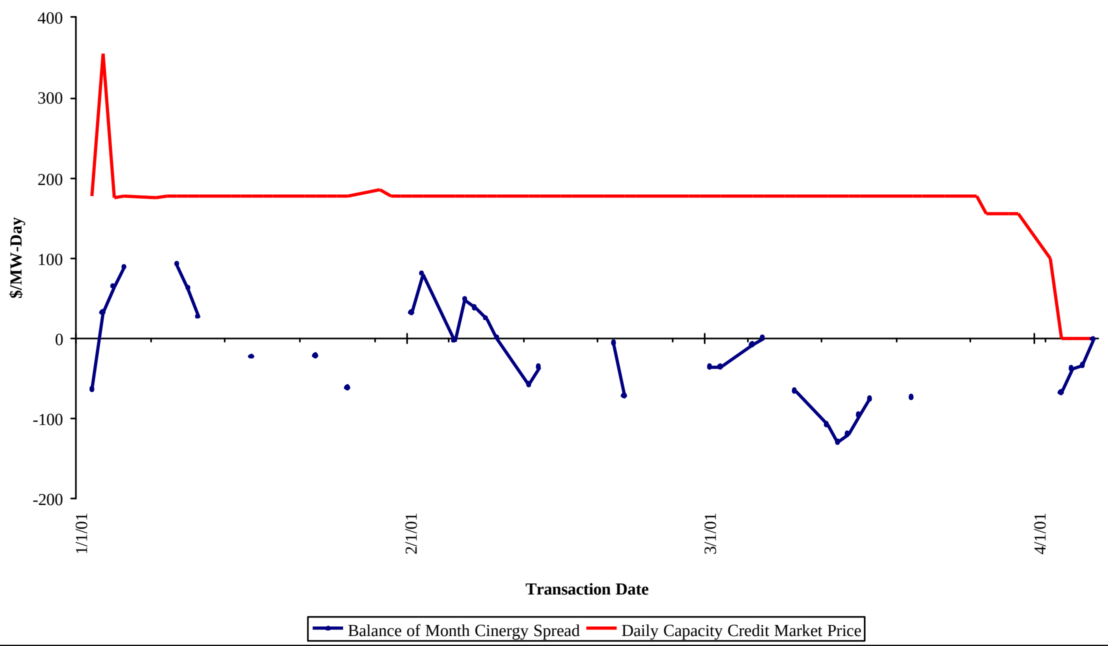
Figure 9 provides a similar comparison for balance of the month forward prices at Cinergy. Again, for the period from January to April, the price in the daily PJM capacity credit market exceeded the spread between the PJM West hub and Cinergy, valued over 16 hours. In other



words, the price of capacity credits in the daily market exceeded the additional value of selling firm energy from that capacity to the Cinergy hub for the balance of the month rather than selling energy to the PJM West hub for the balance of the month.[12]

12 There was inadequate published data for balance of month contracts for sales into New York to include in the graph.

Figure 9: Daily Capacity Credit Market Price and Value of Exporting Firm Energy For Balance of Month Spreads
January to April 2001



The ability of a seller unilaterally to exercise market power in the daily market is a function of the seller's available capacity compared to daily demand and the available capacity of other sellers. If the seller's available capacity exceeds the difference between the daily demand for capacity and the available capacity of all other sellers, the seller has the ability to exercise market power. In effect, such a seller has an effective monopoly position in that it is the only seller of capacity to the residual market demand.

It is clear how Entity1 exercised market power in the daily capacity credit markets. Entity1 offered more total capacity in the daily market than the total net capacity offers in the PJM daily market, i.e. Entity1's offers of capacity were greater than the daily demand for capacity less the capacity offered by all other suppliers.[13] In other words, Entity1 was longer than the total market. To cover their obligations, LSEs had to buy capacity from E1. Entity1 held this market position, in which it offered more capacity than the total net excess capacity offers in PJM, for the period from January 1 to March 30, 2001.

As shown in Figure 10, Entity1 substantially increased its offers of capacity in the daily market as of January 1, 2001. Figure 11 shows that E1 offered capacity amounts well in excess of the total excess offers in PJM, beginning in January and continuing through the end of March 2001,

13 Some LSEs that relied upon the daily market to meet their obligations could have purchased a portion of the capacity needed to meet their obligation for the months of January to April for less than $177/MW-day, if they had purchased in a monthly or multi-monthly auction prior to January 1. In particular, Entity1 offered some capacity in the January to May capacity credit markets, run in October, November and December 2000, at less than $177/MW-day.

although the difference narrowed from late February through late March. Entity1 offers comprised more than half the total offers for the January to March period while the balance of the capacity offers were made by a number of other suppliers.

Figure 10: Daily Capacity Credit Market Supply

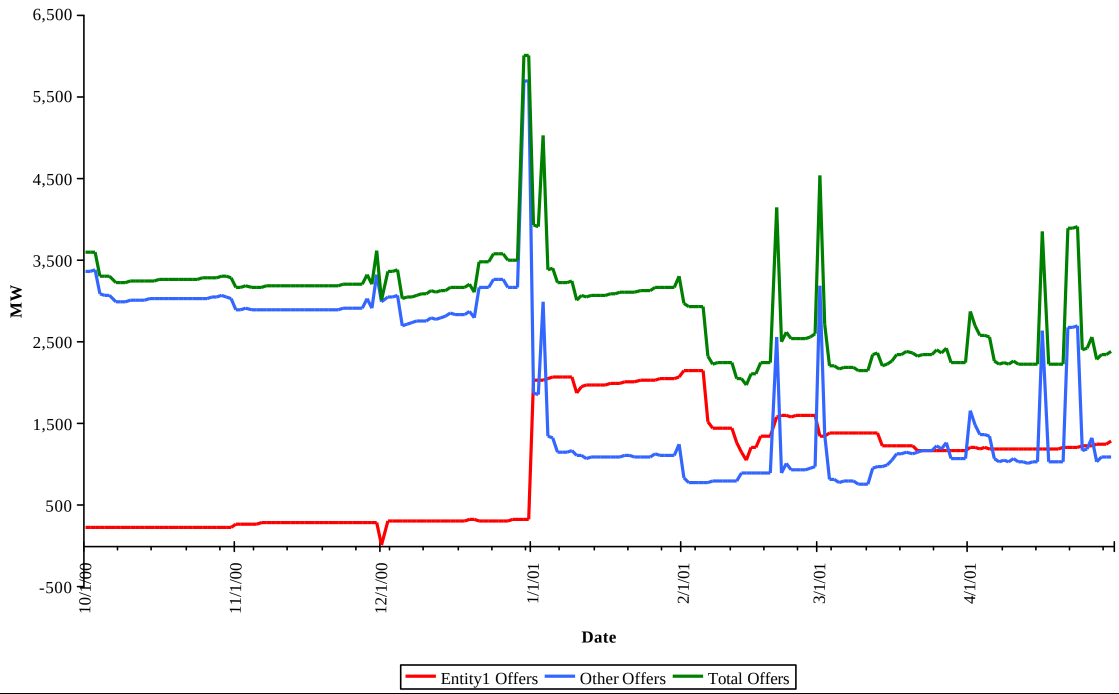
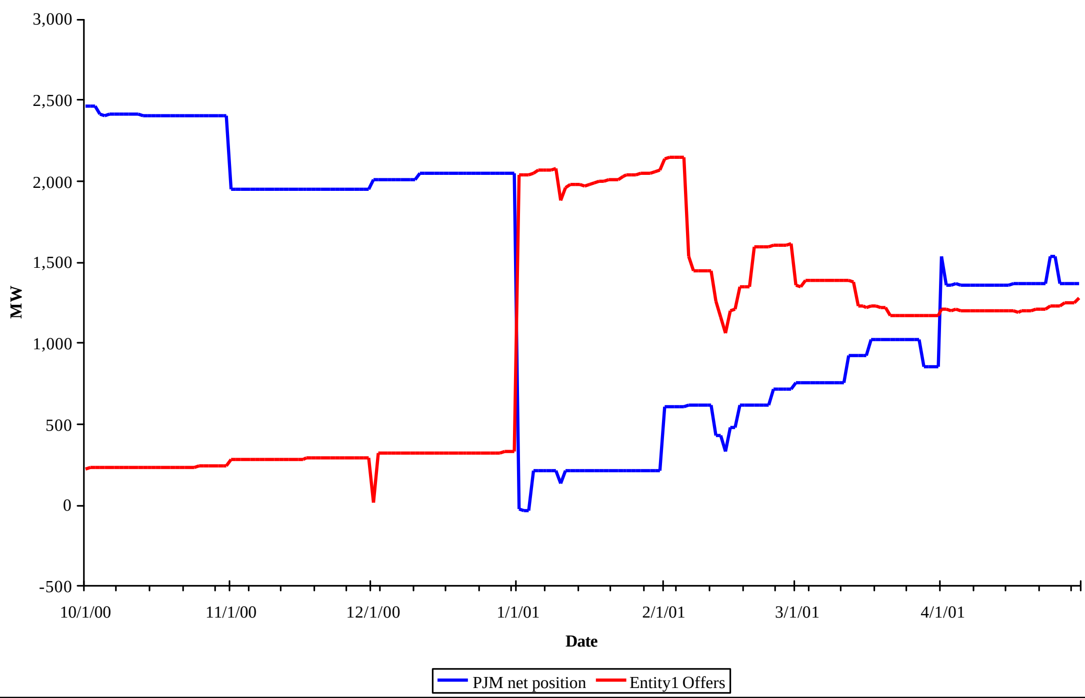


Figure 12 compares the daily capacity, in MW, offered by E1 to the level of demand, in MW, which had to purchase capacity from E1 or be deficient. This residual demand was at its highest levels in January, when it averaged about 1,800 MW/day. The average level of residual demand was 965 MW in February, 381 MW in March and –170 MW in April. The average monthly level of residual demand was between -1,700 MW and -2,200 MW in the months from October through December 2000.

Taken together, Figures 10, 11 and 12 show that since E1 offers of capacity were substantially greater than the total PJM net capacity offers, some buyers of capacity had to buy capacity from E1 if they did not wish to be deficient. If these LSEs became deficient they would be required to pay the capacity deficiency rate of $177.30/MW-day. Entity1's share of total capacity offers put it in a position to set the market price at $177.30. However, if E1 offered capacity to the market at a price greater than $177.30/MW-day, capacity buyers would be better off if they were deficient and paid the $177.30. If buyers were deficient due to inadequate supply offers at a price less than or equal to $177.30, E1 would receive most or all of the deficiency revenues due to the RAA allocation rules in effect at the time, which determined the allocation of the deficiency revenues based on the shares of the total excess capacity.[14]

[14] In fact, E1 was in a better position if they offered capacity at a price in excess of $177.30 because the RAA rules in effect at the time penalized LSEs who were deficient for more than 30 days by increasing the

Figure 11: Daily Capacity Credit Market Supply and Demand



As long as the overall market was extremely tight, in the sense that total supply was very close to total demand, the deficiency revenues accruing to E1 would not be affected if other suppliers priced below $177.30 or if other suppliers decided to follow the same strategy as E1. If other suppliers sold all their MW at $177.30 or below, some buyers would still need to buy from E1. If other suppliers offered capacity at greater than $177.30, every additional MW priced at greater than $177.30 would result in an LSE being deficient by a MW and adding $177.30 to the deficiency payment revenues for distribution across excess MW which would have also increased by 1 MW. The essential fact is that E1 would receive $177.30/MW-day as long as it did not offer capacity at a price below $177.30. There was no competition to constrain E1's ability to set the market price.

While no single other supplier had the unilateral ability to set the market price, the result of even one supplier offering capacity at a price of $177.30, with economic withholding by E1, was a market clearing price equal to $177.30. Rational sellers, recognizing that purchasers were being forced to be deficient, even at elevated prices, offered at least some capacity at a price of $177.30. Rational purchasers, faced with the risk of being deficient, offered to purchase at least some capacity at $177.30. The result was a market clearing price of $177.30. If the supply curve of all other offers was unaffected by E1's behavior, offers by E1 at a lower price would have reduced the price on every day in January, although by a relatively small amount, in general. The offers of other suppliers might have been a function, at least in part, of the offers from E1. The degree to which the daily market prices in January would have been reduced by lower offers

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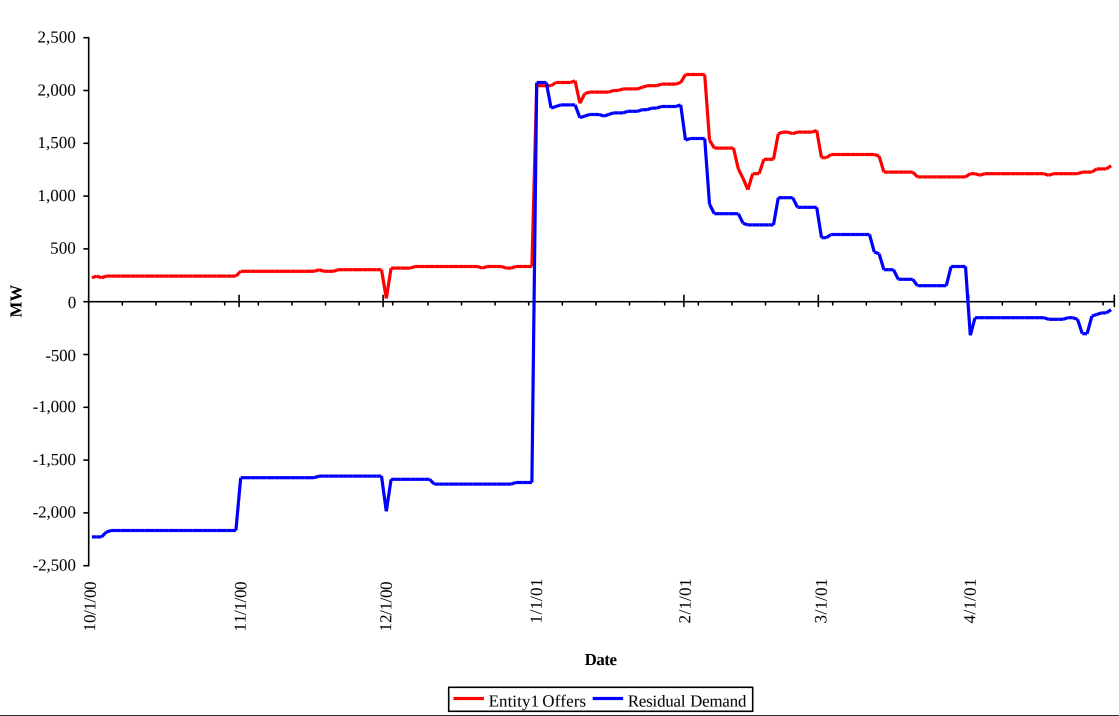
capacity deficiency rate that they must pay. Thus by forcing LSEs deficient, E1 would ultimately increase the capacity deficiency revenues available.

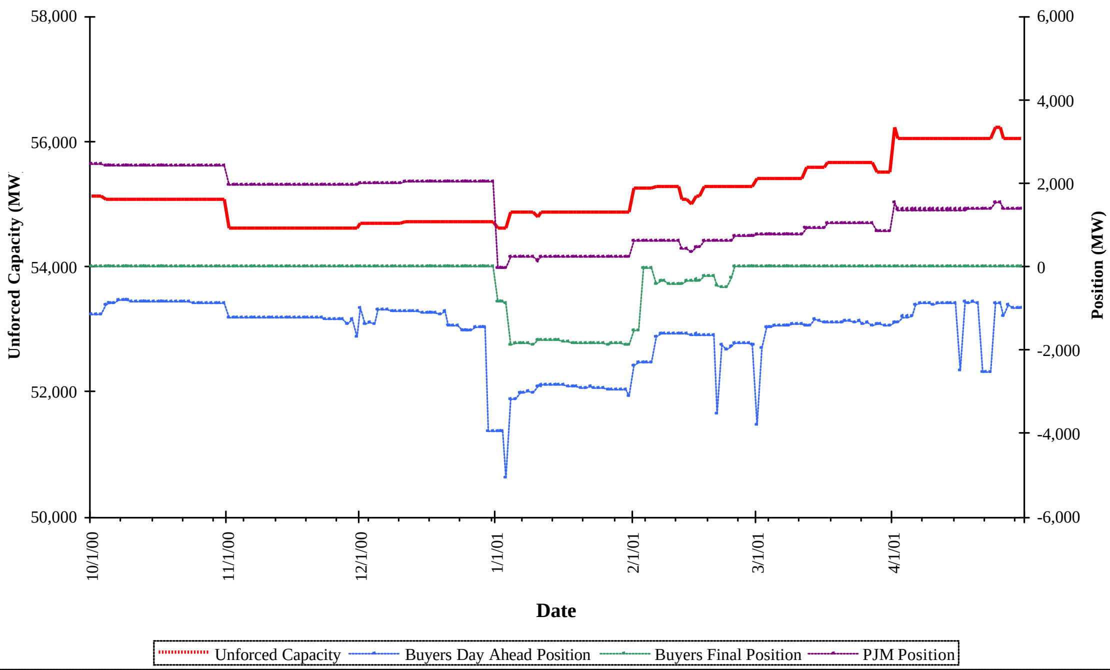
from E1 is a function of the behavior of other suppliers. If other suppliers reacted to lower E1 offers, the price reduction in January that resulted from lower E1 offers could have been significant. In February and March, offers by E1 at a lower price, with no change in the supply curve of all other offers, would have set the market clearing price.

Figure 12: Entity1 Supply and Residual Demand



As shown in Figure 13, buyers of capacity relied on the daily market more heavily in January and February 2001 than in late 2000. The Buyers' Day Ahead Position line in Figure 13 shows the extent to which LSEs needed to purchase in the daily market in order to avoid being deficient. From October 1 to December 31, 2000, capacity buyers relied on the daily market for about 1,200 MW of capacity on average. During January, capacity buyers purchased about 3,000 MW in the daily market, in February about 1,900 MW, in March about 1,500 MW and in April about 1,200 MW in the daily market on average. While capacity buyers purchased their requirements at less than $177.30/MW-day in the daily market from October 1 to December 31, 2000, that was not the case during January and February 2001. In those months, short capacity purchasers were not able to purchase their full capacity requirements in the daily capacity credit market at a price less than or equal to $177.30/MW-day and were deficient as a result, in aggregate, by an average of 1,732 MW per day in January and 346 MW per day in February (Figure 13). Capacity purchasers were not deficient in March and April. Figure 13 also shows the extent to which capacity purchasers met their obligations in the daily capacity credit markets. The Buyers' Final Position line shows the net position of capacity purchasers in the daily market after the daily market has cleared. The Buyers' Final Position line shows that buyers were not deficient after February 24 since the buyers' aggregate net position is zero after that date.

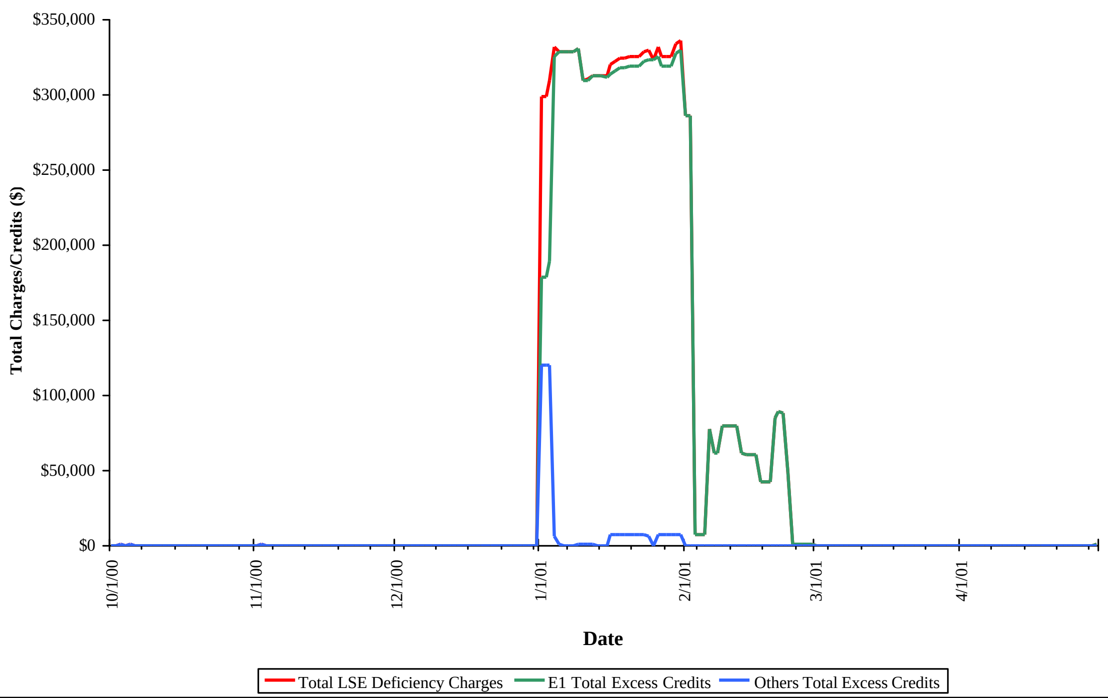
Figure 13: PJM Unforced Capacity and Buyers' Position (Day Ahead and Final)



The deficient LSEs paid capacity deficiency charges equal to $177.30/MW-day for all days on which they were deficient except the day the pool was deficient, when they paid $354.60/MW-day. The total capacity deficiency charges paid was $1,000 or less for the period from October 1 to December 31, 2000 and for the period from March 1 to April 30, 2001. However, total deficiency charges were $11,767,541 from January 1, 2001 to February 24, 2001.

Figure 14 shows that Entity1 captured virtually 100% of the revenues resulting from capacity deficiency charges during the period from January through February.

Figure 14: Deficiency Payments and Credits



Prices through March 2001 stayed near the CDR of $177.30/MW-Day (Figure 5). However, as E1's market position weakened somewhat (Figure 12), E1's strategy changed. E1 reduced the offer price on a portion of its available daily capacity to $177.30 and the MW offers cleared. In March, E1 offered more capacity at $177.30 and as a result all demand bids cleared but the market price remained at $177.30.

In April, PJM's excess capacity increased for a number of reasons including new construction, capacity imports, the rerating of existing units and the reduction of forced outage rates (Figure 6). Some capacity purchasers bought capacity bilaterally, reducing their participation in the daily markets. For the first time since January, the capacity offered by E1 was no longer required in order to meet capacity requirements in the daily market after April 1 (Figure 12). The residual demand was negative. At the same time, Entity1 changed its offer strategy, offering more capacity at lower prices. Prices declined as a result of these factors.

In summary, the MMU concluded that Entity1 did unilaterally exercise undue market power during the first quarter of 2001, resulting in higher prices than would otherwise have occurred. The capacity credit market rules did not expressly prohibit the actions of Entity1, which took the form of economic withholding. Entity1 successfully withheld capacity by offering it at prices higher than the CDR because it held capacity that LSEs needed to purchase to meet their capacity obligations. Entity1 held more net capacity than the total excess capacity in the market.

Change in the Allocation of Deficiency Revenues

New Rules

As described above, under the then existing methodology for allocating deficiency charge revenue, a capacity owner could effectively set the price of capacity at the CDR in circumstances where that owner had excess capacity and LSEs required that excess capacity to meet their obligations (that is, the capacity owner had a longer position than the aggregate pool was long). Under these conditions, the price of capacity results from the interaction of offer behavior by the capacity owner and the economic incentives of an allocation methodology that guarantees that capacity owner a price equal to the CDR.

The result of the above analysis was that the MMU proposed a rule change to the RAA which was ultimately approved and filed with FERC on March 7, 2001.[15] The amended methodology for distribution of deficiency charge revenues expanded the pool of recipients who receive distribution of deficiency charge revenues from all long LSEs and long capacity owners (the current methodology) to all LSEs that complied with their Accounted-For Obligation and all long capacity owners. The result is to reduce the deficiency charge revenues an owner of excess capacity receives on a megawatt basis to a level below the CDR when that lower level is consistent with the market value of the capacity. While under the prior methodology a single capacity owner that is longer than the aggregate pool would receive all deficiency charge revenues, under the amendment such a capacity owner would share those revenues with compliant LSEs when this allocation is greater than or equal to the market value of the capacity.

Under the amendment, if the allocation would result in a distribution to excess capacity owners that was below the market value of the capacity on a $/MW basis, then the long capacity owner would receive the market value of capacity (referred to in the amendment as “Alternate Value”) for the capacity required to meet the total pool obligation.[16] The market value of capacity is defined, in the amendment, to be the difference in the daily forward market energy prices between the Cinergy Hub and PJM’s Western Hub for the applicable day.

Reducing deficiency revenue distribution below the CDR when consistent with the market value of capacity should incent the long capacity owner to sell excess capacity at competitive prices. Specifically, in circumstances where an owner is longer than the pool, the amendment eliminates the owner’s effective power to set the market price at the CDR. Under the amendment, if that owner offers capacity above the CDR, the LSE’s buy bid still will not clear, but, because deficiency revenues will be distributed to a wider group of recipients, such an owner will receive less than the CDR in the distribution, if consistent with the market value of capacity.

Impact of the Change in Allocation Methodology

The revised method for allocating deficiency revenues was implemented on June 1, 2001. Thus far, it is difficult to assess the impact of the change directly. Prices in the daily capacity credit markets fell after March but this is largely attributable to the changed balance in supply and demand in the daily markets described above. Nonetheless, knowledge of the coming change certainly altered the forward-looking profitability of the strategy used during the first quarter. Following the introduction of the interval market on July 1, there was a strong disincentive to

15 Implementation of the rule change required amendment of the RAA. The amendment process entailed initial approval by the PJM Reliability Committee (comprised of LSEs) and further approval by the FERC. The Reliability Committee approved the rule change by a vote of 42 to 2 on February 28, 2001. PJM filed the associated amendment to the RAA on March 7, 2001. The FERC accepted the rule change effective June 1, 2001. PJM Interconnection, L.L.C., 95 FERC ¶ 61,175 (2001). The combination of market conditions and the rule changes resulted in a change in market outcomes after April 1, 2001.

16 The distribution of CDR revenues will never exceed the total CDR revenues paid in by deficient entities.

rely on the daily capacity market to meet obligations. Significantly reduced demand combined with more than adequate supply and the absence of pivotal suppliers resulted in average prices of zero in the daily market from July 1 to December 31.

Introduction of an Interval Market

New Rules

In the State of the Market Report 2000, the MMU concluded that the existence of daily capacity markets created incentives which resulted in a diminution of reliability in PJM when the daily forward price differential between external and internal markets increased such that delisting was more profitable than selling capacity resources into PJM. During the summer of 2000, relatively large amounts of capacity delisted in response to these daily market incentives. On June 1, 2000, for the first time since the introduction of the PJM daily capacity markets on January 1, 1999, the total demand for daily capacity credits in the PJM markets exceeded the total supply of daily capacity credits. In other words, the sum of pool capacity obligations exceeded the sum of capacity made available to PJM. Although adequate physical capacity was present in the PJM region, the owners of that capacity did not sell all of it to PJM LSEs. As a result, the PJM system as a whole was short capacity when compared to peak season generation needs. The delisting persisted throughout the summer, leaving PJM short of capacity on 16 peak season days. As it turned out, mild weather during the summer of 2000 kept this capacity deficiency from producing adverse reliability consequences. But, if the weather had been hotter, then the capacity shortfalls could have put PJM reliability in jeopardy.

In response to the findings of the MMU, the PJM stakeholder group known as the Future Adequacy Working Group (FAWG) met numerous times over the course of eight months and designed the interval market proposal filed with FERC.[17]

PJM filed in April 2001 to introduce an interval capacity market obligation. The FERC accepted these changes effective July 1, 2001.[18] The amendments to the RAA:

- adjusted the time period over which an LSE must commit generation resources to PJM to meet its capacity obligations under the RAA from a daily commitment to a seasonal interval commitment (ranging from three to five months),
- adjusted the deficiency charge provisions to provide for an interval penalty, rather than a daily penalty, when load serving entities have insufficient capacity to meet their capacity obligations under the RAA, and
- required generation owners to commit excess capacity to PJM (capacity not already committed to an LSE) for an entire interval, rather than daily, in order to participate in any distribution of revenues from capacity deficiency charges paid by load serving entities.

The interval market amendments to the RAA retained the revised deficiency charge allocation rules and eliminated the provisions which escalated the CDR payments under certain conditions

17 FAWG met approximately nine times between August 2000 and March 2001. Participation included 25 to 60 representatives from load serving entities, generators, end-use customers, and others. The state commissions and consumer advocates also participated. The amendments were ultimately filed by the PJM Board under Section 206 of the Federal Power Act because the proposals did not meet the supermajority voting requirements under the RAA, as it existed at that time.

18 PJM Interconnection, L.L.C., 95 FERC ¶ 61,330 (2001).

and which doubled the CDR payment when the PJM capacity market was short. These provisions were unnecessary when the minimum deficiency payment by an LSE for being short for a day in an interval was increased from $177.30/MW to $21,630/MW during the summer interval.

Impact of Interval Markets

The impact of the interval markets can be measured in several dimensions including capacity credit market prices, adequacy of capacity resources, volume of transactions by market and ability to exercise market power. By each of these measures, the introduction of interval markets contributed to the more competitive functioning of the capacity credit market.

As Figure 4 shows, prices in the monthly and multi-monthly capacity markets fell steadily from their peak in June to levels more consistent with a competitive market. MW volumes in the daily markets fell significantly starting in July and rose correspondingly in the monthly and multi-monthly markets. LSEs were deficient for 2 MW on average during the summer interval and for 6 MW on average for the fall interval. PJM in aggregate had capacity resources in excess of the total load obligation. While one supplier was pivotal in the daily markets during the first quarter of 2001, no suppliers were pivotal in the daily markets during the summer or fall intervals.

Summary

As the result of changes in underlying market conditions, of actions by market participants and of rule changes proposed by PJM and accepted by the FERC, LSE reliance on the daily market has decreased and prices have declined in the daily, monthly and multi-monthly markets to levels more consistent with a competitive outcome. (See Figure 4.) The capacity credit market continues to be the focus of significant attention by PJM and its members.

PJM recognizes the need for continued improvement to the ICAP market and is working to develop new solutions that address the needs associated with retail choice as well as the unique reliability requirements of this region. The situation in the daily capacity market in the first quarter of 2001 was an extreme case where a single supplier was pivotal and had the ability to set the market price above a competitive level. It is important that PJM recognize that while the change in the allocation methodology and the introduction of the interval market have clearly improved the functioning of the capacity market, structural conditions in the capacity market are still conducive to the exercise of market power.

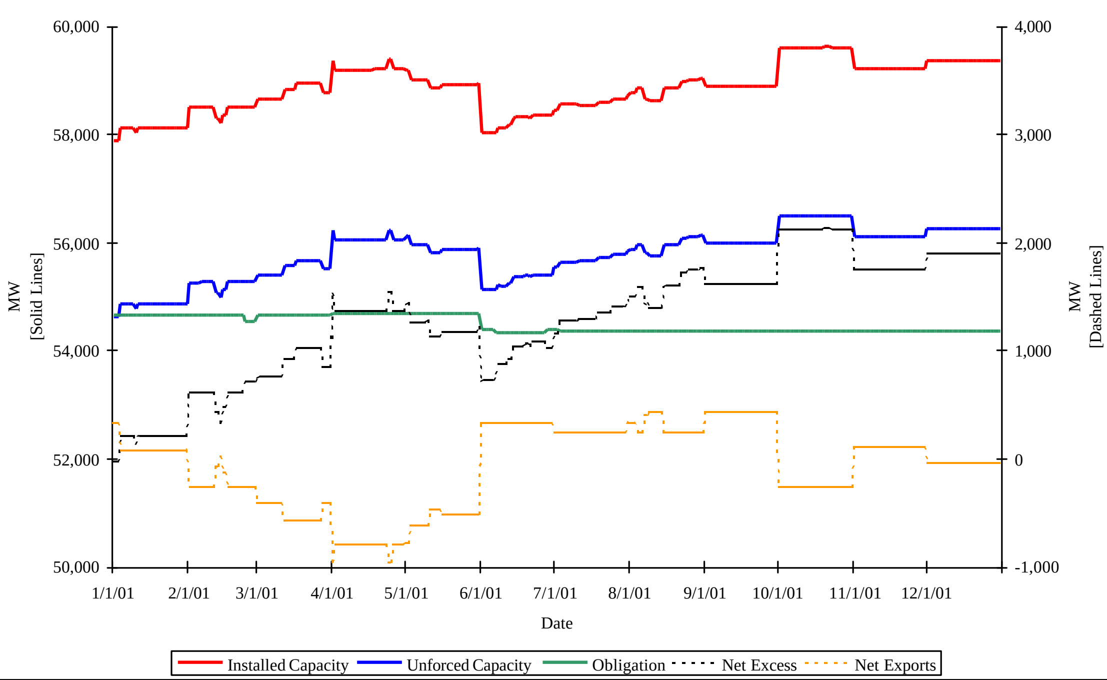
Capacity Market Data: 2001

The balance of this section provides PJM system-wide data and analysis of the capacity markets for the year 2001. The data include the components of the capacity markets: installed capacity, unforced capacity, obligation, excess, deficiency, imports, exports (delists), internal bilateral transactions, capacity credit market exchanges and Active Load Management (ALM) credits. The Appendix to this section defines and describes the principal components of capacity requirements in further detail.

Capacity Supply and Demand in PJM

During 2001, capacity resources exceeded capacity obligation by approximately 1,300 MW on average (Table 3). PJM was capacity deficient for three days in January, as shown in Figure 15. While the pool capacity obligation is determined for the year, the amount of capacity resources in PJM on any day is a function of the addition of new resources, the retirement of old resources and of decisions to list or delist capacity resources which in turn are a function of short-term market forces.

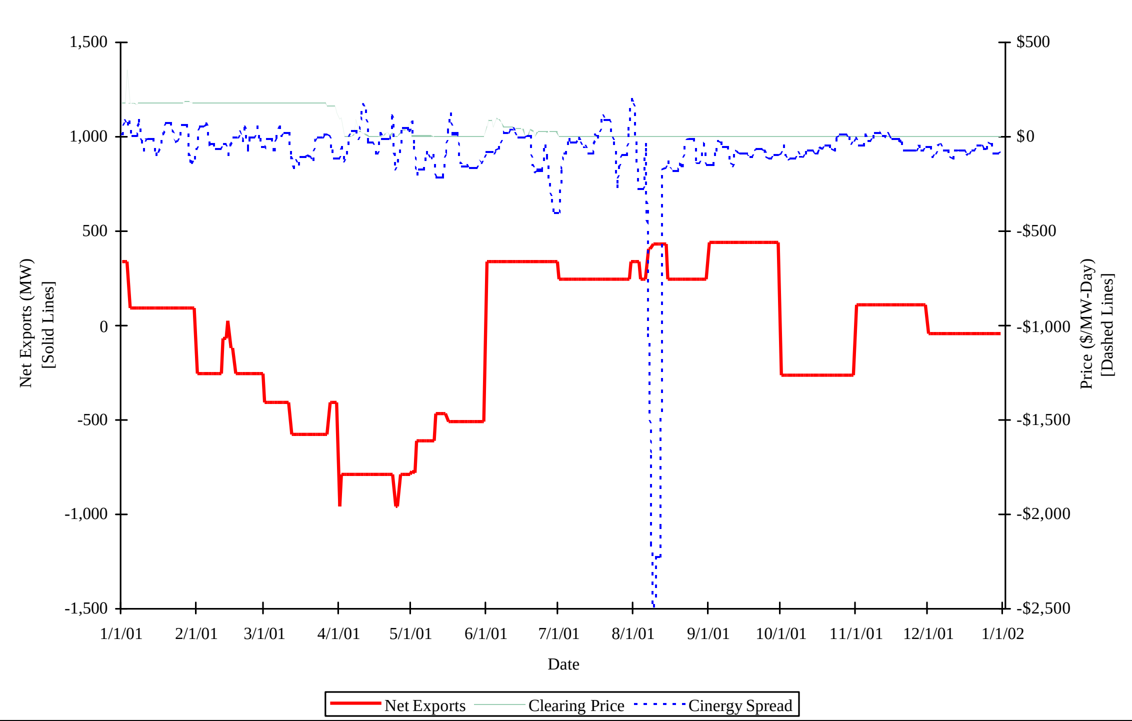
Figure 15: Capacity Obligation
January through December 2001



Exporting (Delisting) Capacity

As shown in Figures 15 and 16, owners of capacity increased their external sales of capacity resources for the summer period although there was no systematic difference between external daily forward energy prices and PJM 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.[19]

Figure 16: PJM Daily CCM Price vs. Cinergy Spread and Net PJM Exports



System Capacity, Obligation, and Net Excess Capacity[20]

System net excess capacity can be determined using installed capacity, unforced capacity, obligation, the sum of members' excesses, and the sum of members' deficiencies. Table 3 presents these data for 2001. The net excess is the net pool position, and reflects a comparison of total capacity resources and obligation. Obligation includes expected load plus a reserve margin. Thus a net pool position of zero is consistent with the established reliability objectives. During 2001, the pool was, on average, long by about 1,300 MW. The maximum and minimum net excess capacity data indicate that the pool was long by about 2,100 MW on one or more days and that the pool was deficient on one or more days by a maximum amount of about 30 MW. A deficiency means that there were less capacity resources in the pool than required to meet the pool's reliability objectives as defined by the total capacity obligation of all LSEs.

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19 These daily forward prices are for weekdays, which are not holidays, only.

20 These data are posted on a monthly basis at www.pjm.com under the Market Monitoring Unit link. Each item presented in this section is a PJM system total, expressed in MW of unforced capacity, unless otherwise noted.

Table 3: Summary of members' capacity, January – December, 2001 (MW)						
	Mean	Minimum	Maximum	Standard Deviation	Increase from 2000	Per Cent
Installed capacity	58,858	57,876	59,618	445	1,452	2.5%
Unforced Capacity	55,786	54,623	56,500	463	1,896	3.5%
Obligation	54,488	54,321	54,690	150	1,790	3.4%
Sum of Excess	1,482	648	2,151	425	249	20.2%
Sum of Deficiency	184	0	1,893	502	143	357.2%
Net Excess	1,299	-29	2,136	543	105	8.8%
Imports	739	453	970	152	304	70.0%
Exports	669	0	1,246	431	-288	-30.1%
Net Exports	-70	-960	435	384	-592	-113.4%
Internal Bilateral Transactions	59,336	43,502	69,382	9,137	27,801	88.2%
Daily Capacity Credits	829	57	4,186	676	-475	-36.5%
Monthly Capacity Credits	663	291	1,569	382	29	4.5%
Multi-Monthly Capacity Credits	534	228	1,029	260	-393	-42.4%
All Capacity Credits	2,025	1,197	4,962	695	-839	-29.3%
ALM Credits	1,851	1,693	2,002	133	32	1.8%

Bilateral Capacity Transactions

PJM capacity resources may be traded bilaterally within and outside of the PJM control area. Table 3 presents PJM bilateral capacity transaction data for 2001. In 2001, an average of 739 MW of capacity resources was imported into PJM and an average of 669 MW was exported (delisted) for an average net import of 70 MW of capacity resources. The maximum net export (delist) was 435 MW, while the maximum net import was 960 MW.

PJM Capacity Credit Market

PJM operates daily, monthly and multi-monthly capacity credit markets. Table 3 presents data on these markets in 2001. In 2001, the daily capacity credit market averaged 829 MW of transactions, or about 1.5% of the average capacity obligation. Trading in PJM capacity credit markets in 2001 showed a decrease over trading in these markets in 2000.

Active Load Management Credits

Active Load Management (ALM) reflects the ability of individual customers, under contract with their local utility, to reduce specified amounts of load when PJM declares an emergency. ALM credits, measured in MW of curtailable load, reduce LSE's capacity obligation. Data on ALM credits in PJM during 2001 are presented in Table 3. In 2001, ALM credits averaged 1,851 MW, up slightly from the level of 1,819 MW in 2000.

Appendix

The general requirement for each Load-Serving Entity is:

Sum of *Unforced Capacity* from *capacity resources* $\geq$ *Unforced capacity obligation.*

Where:

Unforced Capacity for capacity resource "i" = (*Installed capacity*$_i$) * (*12 mo rolling average EFORd*$_i$)

Unforced capacity obligation[21] *for LSE "j"* = [(*Weather-adjusted actual coincident peak load*$_j$ * *Diversity factor*) - *ALM adjustment*$_j$] * [(1 + *PJM Reserve margin*) * (1 – *PJM 5yr average forced outage rate*)]

Unforced capacity and unforced capacity obligation are compared on a daily basis to determine whether a Load-Serving Entity is deficient. A deficiency results in a penalty of $160/MW-day of deficiency, or, in unforced capacity terms, $177.30/MW-day. Both the capacity and obligation sides of the equation can change on a daily basis, as illustrated in the data presented in this section.

The outage rates used in crediting units with capacity are based on the 12-month rolling average outage rates for the units, applied with a two-month lag. An unusually high occurrence of forced outages on a given day would not affect the amount of unforced capacity credits effective that day, but would affect the amount of capacity credits for 12 months starting two months after the event. The capacity obligation in capacity markets is based on the prior summer's weather-adjusted actual peak load, prior year ALM load credits and the approved forecast reserve margin. A significant increase in observed loads would not have an impact on the current year capacity obligation.

Definitions of key capacity market terms are presented below:

- **Capacity Resource**. Capacity which is either committed to serving capacity obligations within PJM or capacity from resources within the PJM control area which are accredited to the PJM control area per the RAA.
- **Installed Capacity.** System total installed capacity measures the sum of the *installed capacity* (in installed terms, not unforced terms) from all internal and qualified *external resources* designated as PJM *capacity resources.* Installed capacity can change on a daily basis principally due to exports (delisting) and imports of capacity or when a physical change is made to a generating unit.
- **Unforced Capacity**. System total unforced capacity is the installed capacity adjusted for outage rates. Installed capacity was between 6.2 percent and 7.0 percent greater than

21 Schedule 7 of Reliability Assurance Agreement Sections B.1 and B.2. The Forecast Pool Requirement is defined in Schedule 4.1 and can be simplified to (1+ reserve margin) * (1-forced outage rate).

unforced capacity over this time period, reflecting unforced outage rates in effect over the time period.

- **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.
- **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).
- **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*.
- **Net excess.** The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of LSE's obligations.
- **Imports.** The sum of all *external transactions* where a qualified *external resource* is designated as a PJM *capacity resource*. Capacity imports from external units must be certified as deliverable using firm transmission, and non-recallable by any external party.
- **Exports.** The sum of all *external transactions* where all or part of an internal generating unit is removed from *capacity resource* status to sell the capacity to a destination outside the PJM control area. Exports of capacity mean that the capacity is delisted from its capacity resource status in PJM.
- **Net exports.** Capacity exports (or delists) less capacity imports.
- **Internal bilateral transactions**. Bilateral transactions of capacity where the source and sink are internal to the PJM control area. Internal bilateral transactions may reflect capacity credits or unit-specific transactions.
- **Daily Capacity Credit Market (Daily CCMs).** The *Capacity Credits* cleared through PJM daily *capacity credit markets (CCMs)*.
- **Monthly CCMs.** The *Capacity Credits* cleared through PJM single month *capacity credit markets (CCMs)*.
- **Multi-monthly CCMs**. The *Capacity Credits* cleared through PJM multi-monthly *capacity credit markets (CCMs)*.
- **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.

ANCILLARY SERVICES

Summary and Conclusions

Regulation is one of six ancillary services defined by FERC in Order No. 888. Regulation is required in order to match generation with short-term increases or decreases in load that would otherwise result in a short-term imbalance between the two. Longer-term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. The PJM regulation market supplanted an administrative and cost-based regulation procurement mechanism that had been in place for many years.

Consistent with its incremental approach to the introduction of new markets, PJM introduced the regulation market on June 1, 2000 after 14 months experience with a market-priced energy market. Market participants can now acquire regulation in the regulation market in addition to self-scheduling their own resources or purchasing regulation bilaterally. The new regulation market is a step towards PJM's goal of implementing a market-based approach to all components of the energy, capacity and ancillary services markets, where it is viable.

The MMU has reviewed the structure of the regulation market, the number and nature of regulation offers, the level of regulation prices and system regulation performance since the implementation of the regulation market. The MMU has concluded that the regulation market functioned effectively and was competitive in 2001. Concerns about the structure of ownership in the regulation market are offset at present by the available supply of regulation capacity from PJM resources relative to the demand for regulation (Figure 1). The price of regulation in the market was approximately equal to the price under the administrative and cost-based system (Figures 2 and 3) and the price exhibited the expected relationship to changes in demand (Figure 4). There is the potential for various forms of non-competitive behavior in the energy market to affect the regulation market, although there is no evidence of such an issue during 2001. The introduction of a market in regulation has resulted in a significant improvement in system regulation performance, measured by the availability of regulation (Figure 5) and by NERC Control Performance Standards CPS1 and CPS2 (Figure 6) which continued in 2001.

Spinning reserve is another ancillary service, defined to be generation that is synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can be provided by a number of sources including steam units with available ramp, condensing hydro units, condensing CTs, CTs running at minimum generation and steam units scheduled day ahead to provide spinning. PJM plans to introduce a market in spinning reserves during 2002.

The total level of required spinning reserves ranged from about 1,100 MW to 1,500 MW from 1999 to 2001 and averaged about 1,200 MW (Figure 8). The costs associated with meeting PJM's demand for spinning reserves declined during 2001 from about $30/MW in January to $17/MW in December (Figure 7).

Regulation Service

The PJM control area maintains regulating capability to eliminate any short-term imbalances between the supply and usage of energy. 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.

The regulation service supplied by individual generating units is defined as: "The capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal." The generating units assigned to meet PJM regulation requirements must be capable of responding to the Area Regulation (AR) signal within five minutes and must increase or decrease their outputs at the ramping capability rates specified in the unit-specific offer data submitted to PJM.

Not all generating units are equipped to provide regulation service. Moreover, the amount of regulation a properly equipped generating unit can supply is limited by the physical ability of the unit to increase or decrease output within the required five minutes. The regulation capability of an individual generator is the difference between its current operating level and the level that it could ramp to, either up or down, within five minutes. Of the 540 generating units in the PJM area[1], 114 are qualified to provide regulation.[2] In the PJM area there are more than 59,000 MW of generating capacity while about 1,802 MW of regulation capability have been identified in this analysis.[3]

The PJM control area establishes separate area-wide regulation requirements for both peak hours (hours ended 0600-2400) and off-peak hours (hours ended 0100-0500 hours). The regulation requirement for the peak period is 1.1 percent of the forecast peak load; for the off-peak period it is 1.1 percent of the valley load forecast.[4] During 2001, this requirement ranged from approximately 200 MW of regulation capability for the off-peak period to approximately 600 MW for the peak period.

Responsibility for the control area's hourly regulation requirement is assigned to all Load Serving Entities (LSEs) within the PJM control area based upon each LSE's share of the control area's hourly load. The LSE's regulation obligation can be met by self-scheduling of its own generators, bilateral purchases or purchases through the PJM operated regulation market.[5]

Regulation for the PJM control area must be supplied by generators located within its metered electrical boundaries. Thus, the largest relevant geographic market for regulation service in PJM is the PJM control area. Within the control area, there are no geographic restrictions on either generators that can supply regulation service, or transmission costs involved in supplying regulation. In general, even when there are internal transmission constraints within PJM, regulation still can be supplied from any generators electrically within the PJM control area. Suppliers in the relevant geographic market include all entities owning generating capacity in the market that is equipped to provide regulation.

1 Mid Atlantic Area Council, Regional Reliability Council EIA-411 Report, April 1, 2001.
2 In this analysis, the units which are qualified to provide regulation are those which have actually offered to provide regulation in the day ahead market during 2001.
3 This regulation capability is net of forced outages based on average forced outage rates.
4 PJM Manual for Scheduling Operations, Manual M-11, page 3-4.
5 PJM Open Access Transmission Tariff, Attachment K--Appendix.

As noted, internal transmission constraints do not affect the geographic extent of the regulation market. However, internal transmission constraints may affect the cost structure of regulation offers via their impact on opportunity costs, an important component of such offers. As an example, if, on a day-ahead basis, the eastern interface is constrained, regulation to the west of the interface could be more economic than regulation to the east. The eastern interface constraint could make LMPs higher to the east and thus could increase the regulation market offers of units in the east by increasing the opportunity costs of those units relative to the units in the west. Then the western supply of regulation could serve the entire system because the amount of regulation required is quite small in comparison to the size of the eastern interface transmission limit and would have no significant impact on operating the system.[6] The actual opportunity costs of specific units would depend both on the LMP at the unit bus and the energy offer of the unit. (The opportunity cost is the difference between the LMP and the energy offer.) In general, the amount by which the opportunity costs in the east and the west differ would be a function of both the LMPs in the east and west and the energy offers of regulating units in the east and west and could vary over a wide range, from positive to negative.

The Regulation Market

Generators wishing to participate in the PJM regulation market submit offers for specific units by 1800 of the day prior to the operating day. Regulation offers include the attributes of the unit's regulation capability and are subject to a \$100/MWh offer cap. PJM uses the day-ahead LMPs and generation schedules, which result from clearing the day-ahead market, together with the regulation offers, to calculate opportunity costs by unit for each hour of the operating day. Regulation offers and opportunity costs are added to create a total offer price which, in aggregate, results in a regulation supply curve. The supply curve and the PJM demand curve for regulation are used to calculate a Regulation Market Clearing Price (RMCP).

During the operating day, PJM calculates the actual opportunity cost for each unit based on the real-time LMPs. The real-time opportunity costs and the regulation offer prices are added to create a total offer price for each unit and to create, in aggregate, a real-time supply curve. The real-time supply curve is used to select the most economic units to supply regulation in real time. Units selected to provide regulation in real time are compensated at the higher of the RMCP or the regulation offer plus the real-time opportunity cost.[7]

For units that were made available for energy and regulation in the day-ahead market, regulating capability can be decreased but not increased during the operating day. This market rule is designed to prevent withholding from the regulation market, which determines the RMCP, and then providing regulation at the resultant higher price during the operating day. In order to effect decreases in regulating capability in real time, regulating units can modify certain attributes of their offer on an hourly basis in real time including regulation capability in MW, regulation limits in MW and regulation status. Regulation capability is the MW amount by which the unit

[6] For example, transmission capability into the eastern portion of PJM from the rest of PJM is, in general, approximately 6,000 MW. (The precise number varies depending upon actual operating conditions on the network.) The regulation requirement for the eastern portion of PJM alone would be about 250 MW. The regulation requirement in the east, net of self-scheduled requirements, would be even lower.

[7] The use of actual opportunity costs, calculated by PJM, permits generators to be compensated for opportunity costs without requiring the addition of a risk premium to the offer to cover the risk associated with a distribution of opportunity costs which is unknown before the fact.

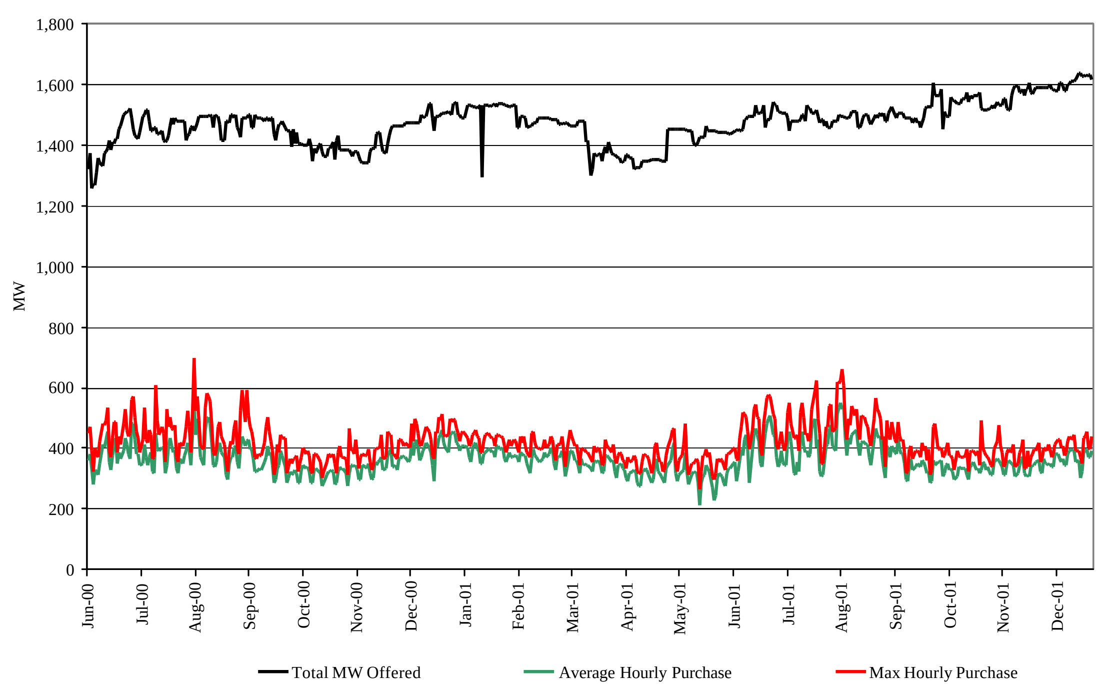
can change output within five minutes in response to the regulation signal. Regulation limits refer to the maximum and minimum MW a unit can produce while providing regulation. Regulation status refers to whether the unit is available or unavailable to provide regulation and whether the unit is self-scheduled for regulation. Real-time changes to regulation status can include: available to unavailable, self-scheduled to unavailable and available to self-scheduled. Units that were not made available for energy in the day-ahead market but become available during the operating day may be made available to provide regulation to the market or to be self-scheduled in real time. Bilateral regulation transactions are accounting transactions that take the form of transferring regulation obligation between parties. Bilateral transactions can be entered through 1200 the day after the transaction starts.

When units are paid RMCP, the positive difference, if any, between RMCP and the sum of the unit specific offer price and the unit specific opportunity cost, is a credit against PJM's obligation to pay make-whole operating reserves from the energy market. PJM guarantees that a generator will receive all start up and no load costs not covered by energy market payments. Any such payments are made from operating reserves. The difference between the market clearing price received by a unit in the regulation market and unit specific regulation costs also offsets any unrecovered start up and no load costs and thus reduces operating reserve payments.

Regulation Market Structure

The MMU recommended, in an affidavit filed with FERC, 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 or Herfindahl-Hirschman Index.[8] Concentration ratios measure the concentration of ownership in a market, in this case, the ownership of regulation assets. The HHI is the sum of the squares of the market shares of the firms in a market. An analysis of HHIs since the introduction of the regulation market indicates that seasonal HHIs fall between 1700 and 1800, which is categorized as "moderately concentrated" under the 1992 joint Department of Justice/Federal Trade Commission Horizontal Merger Guidelines and FERC's 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. Offsetting these concerns, the available supply of regulation is substantially larger than the demand for regulation. During 2001, the total regulation offers exceeded regulation purchases by a factor of about three as illustrated in Figure 1.

Figure 1: Regulation MW Offered Versus MW Purchased



8 Federal Energy Regulatory Commission, Docket No. ER00-1630, Affidavit of Joseph E. Bowring, February 2000.

Regulation Market Results

As Figure 2 shows, despite several significant, short-lived spikes in the cost of regulation, most notably in the summer of 1999, in May 2000 and in August 2001, hourly regulation costs have been relatively stable since January 1999. Price spikes were 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 LMP and the regulation cost. Price spikes occur under the regulation market when high energy prices increase the opportunity cost component of the regulation offers.

Figure 2: Hourly Regulation Cost Per MW

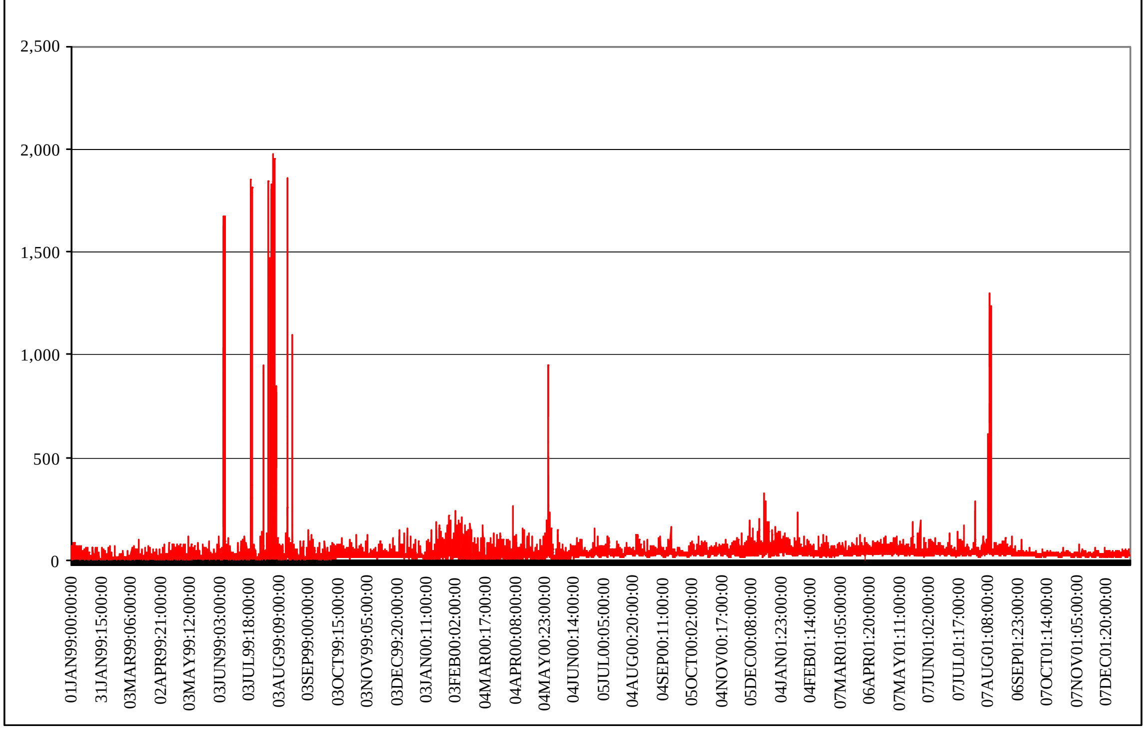
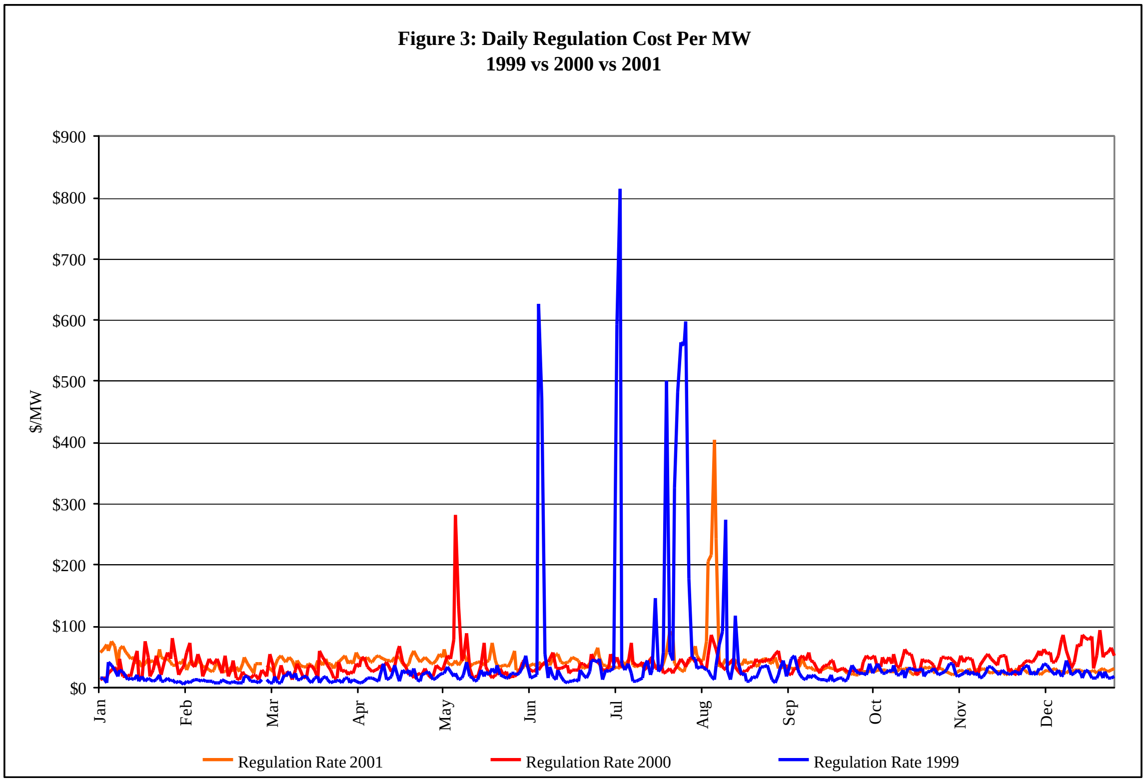


Figure 3 compares the average daily cost of regulation for 1999, 2000 and 2001 (including the seven months in 2000 after the introduction of the regulation market). The total cost of regulation was 10% higher in 2001 than in 2000 and 2.1% higher than in 1999. The per unit cost of regulation was 1.6% higher in 2001 than in 2000 and 3.6% lower than in 1999.

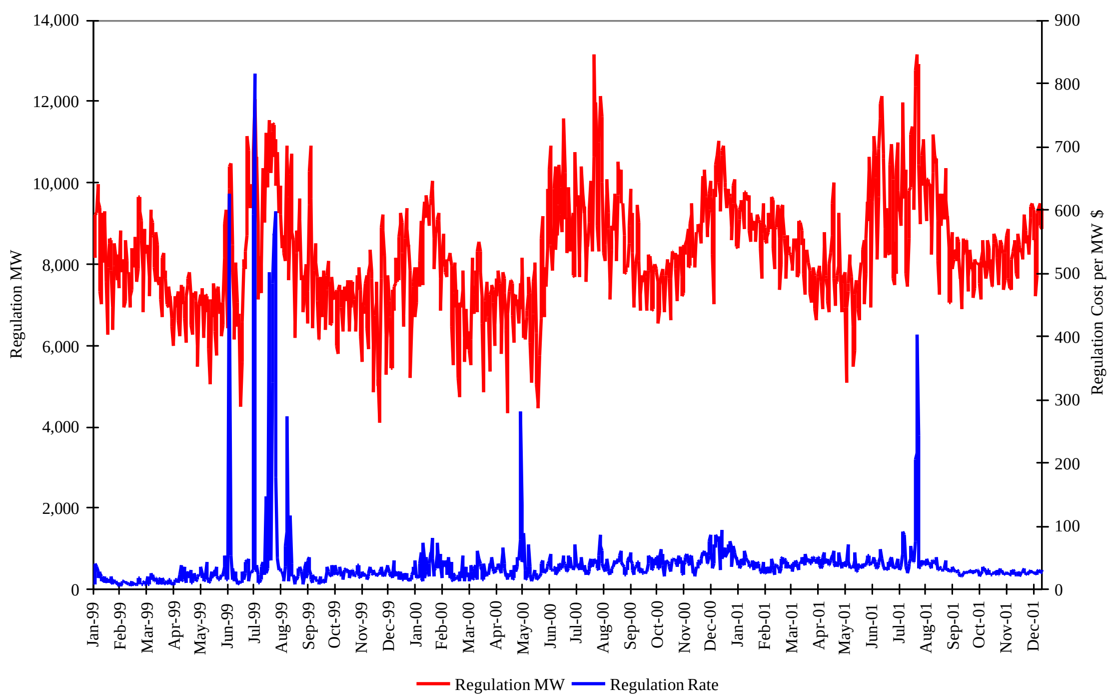


The data presented in Figures 2 and 3 show that the average per unit price of regulation during the first nineteen months of the market was approximately equal to the price of regulation under the cost-based system in place prior to market implementation. This test suggests that the regulation market has been competitive since its introduction.

Figure 4 compares the regulation cost per MW to the demand for regulation for the period from January 1999 through December 2001. Since the introduction of a regulation market, the per unit cost of regulation spikes when system LMP spikes. The demand for regulation is a linear function of forecast energy demand, as noted above. When loads increase, the demand for regulation increases as a result. In addition, increases in system LMP lead to an increase in opportunity costs when the spread between LMP and the energy offers of the regulating units increases. The system LMP increases when load increases and higher price units must be dispatched to meet demand. As a result, load, energy prices and regulation prices are highly correlated.

The data presented in Figure 4 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 regulation market was competitive in 2001.

Figure 4: Daily Regulation MW Purchased Compared to Cost Per Unit



The close relationship between the regulation market and the energy market is essential for the efficient and competitive provision of both energy and regulation. However this close relationship also creates the potential for market issues in the energy market to be transferred to the regulation market. For example if the price in the energy market is above competitive levels, this will tend to increase the price of regulation. Economic withholding in the energy market could also impact the regulation market. While there is no evidence that such behavior affected the price of regulation in 2001, the potential for issues requires ongoing scrutiny.

Regulation Performance

Under both under the prior administrative approach and the 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 could well 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. The regulation market design provides better incentives to owners based on current, unit-specific opportunity costs and the submission of a current regulation offer price.

Figure 5: Percent of Hours Within Required PJM Regulation Limits

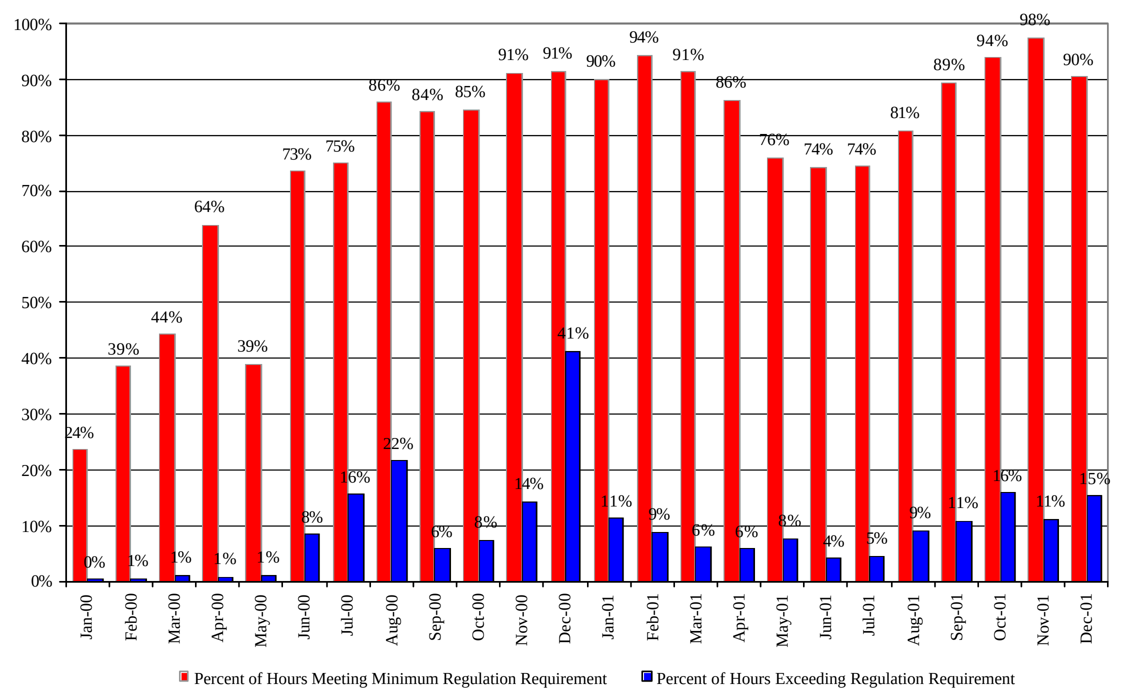


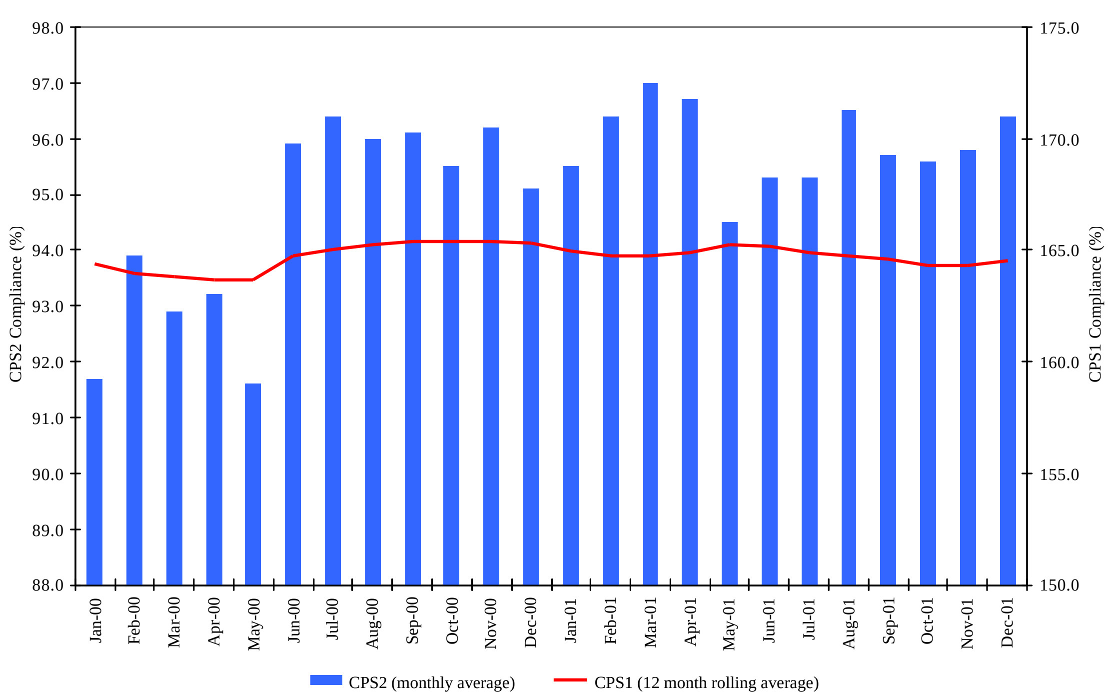
Figure 5 shows that during the first five months of 2000, the supply of regulation was consistently less than the target level of regulation. After the introduction of the regulation market, the availability of regulation increased significantly. The proportion of hours in which PJM met the minimum regulation target doubled from an average of about 42% in the first five months of 2000 to about 87% in the months after the introduction of the regulation market. The proportion of hours in which PJM exceeded the minimum regulation target increased from less than 1% in the first five months of 2000 to more than 12% on average in the nineteen months after the introduction of the regulation market.

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. The balance between load and generation is defined in terms of the frequency of the system, measured in Hertz (Hz).

Regulation is the PJM control action to correct for changes in load or generation that may cause the power system to operate above or below 60 Hz. The response to the PJM regulation control action is the variable energy produced by units under automatic control, independent of the economic cost signal and within five minutes of the need for it.[9] While the improved availability of regulation illustrated in Figure 4 is important, the ultimate success of regulation in balancing load and generation is measured by NERC Control Performance Standards CPS1 and CPS2.[10]

Figure 6 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 the control area meets it demand requirements. CPS2 measures the balance between load and generation on a 10-minute basis. Figure 6 shows that performance, as measured by both CPS1 and CPS2, has improved since the introduction of the regulation market.

Figure 6: CPS1 and CPS2 Performance



The data presented in Figures 5 and 6 illustrate the improvement in regulation performance which occurred after the implementation of the regulation market. The evidence is consistent with a significant increase in performance resulting from the introduction of a market. As with the other evidence, it must be remembered that the regulation market has been in place for only

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

10 NERC Operating Manual, March 29, 2001.

nineteen months and that further experience is required before a final conclusion can be reached regarding the competitiveness of the regulation market. The early evidence is quite positive.

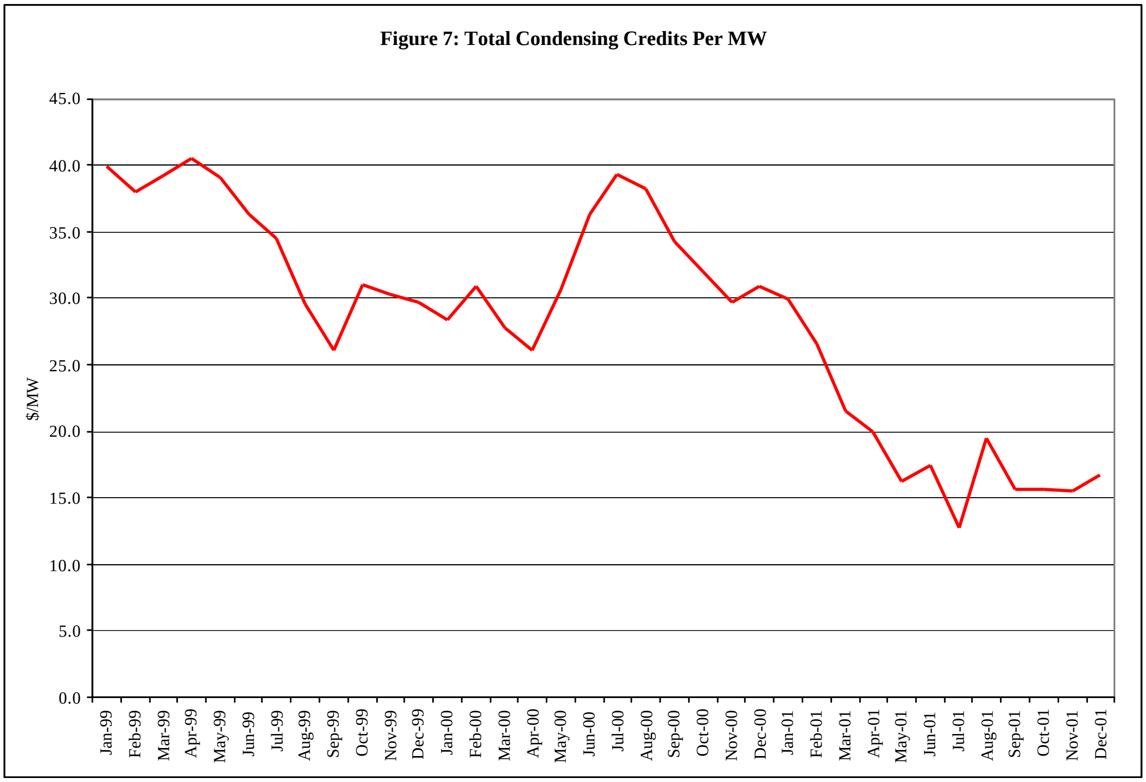
Spinning Reserve Service

PJM plans to introduce a market in spinning reserves during 2002. Some basic features of the supply of and demand for spinning reserves during 2001 are presented here as a benchmark for the introduction of a market.

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 be provided by a number of sources including steam units with available ramp (incidental spinning), condensing hydro units, condensing CTs, CTs running at minimum generation and steam units scheduled day ahead to provide spinning.

There are three types of operating reserve on the PJM system: spinning reserve, 10 minute or quick start reserve and 30 minute reserve. Primary reserve is equal to spinning reserve plus quick start reserve. Secondary reserve is the total 30 minute reserve less the primary reserve, or all reserve capable of providing energy in from 10 to 30 minutes. The three types of operating reserves are additive. The level of spinning reserves covers part of the requirement for quick start reserves and both the level of spinning reserves and quick start reserves cover part of the requirement for 30 minute reserves.

The total level of required spinning reserves ranged from about 1,100 MW to 1,500 MW from 1999 to 2001 and averaged about 1,200 MW. (See Figure 8.)



The costs associated with meeting PJM's demand for spinning reserves declined during 2001. Figure 7 shows the decline from about $30/MW in January to $17/MW in December. Figure 8 compares the total amount of required spinning reserve to the amount of spinning reserves purchased on an average hourly basis. The difference between required spinning reserve and spinning reserve provided by condensing units is provided by units which are following the PJM dispatch signal but which are not at maximum output and have available ramp, or the capability to increase output within 10 minutes. This incidental spinning is not explicitly compensated under current market rules. Figure 9 shows the annual average hourly condensing MW purchased by PJM since 1998.

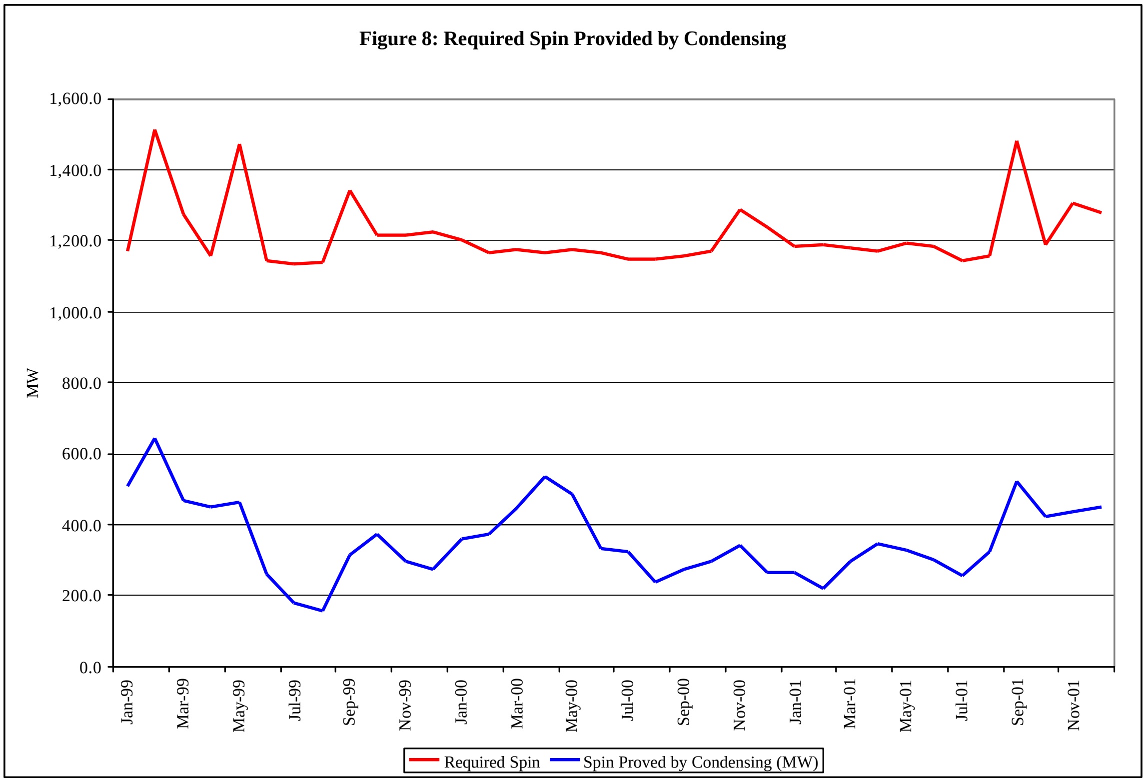


Figure 8: Required Spin Provided by Condensing
MW
1,600.0
1,400.0
1,200.0
1,000.0
800.0
600.0
400.0
200.0
0.0
Jan-99
Mar-99
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Required Spin
Spin Proved by Condensing (MW)

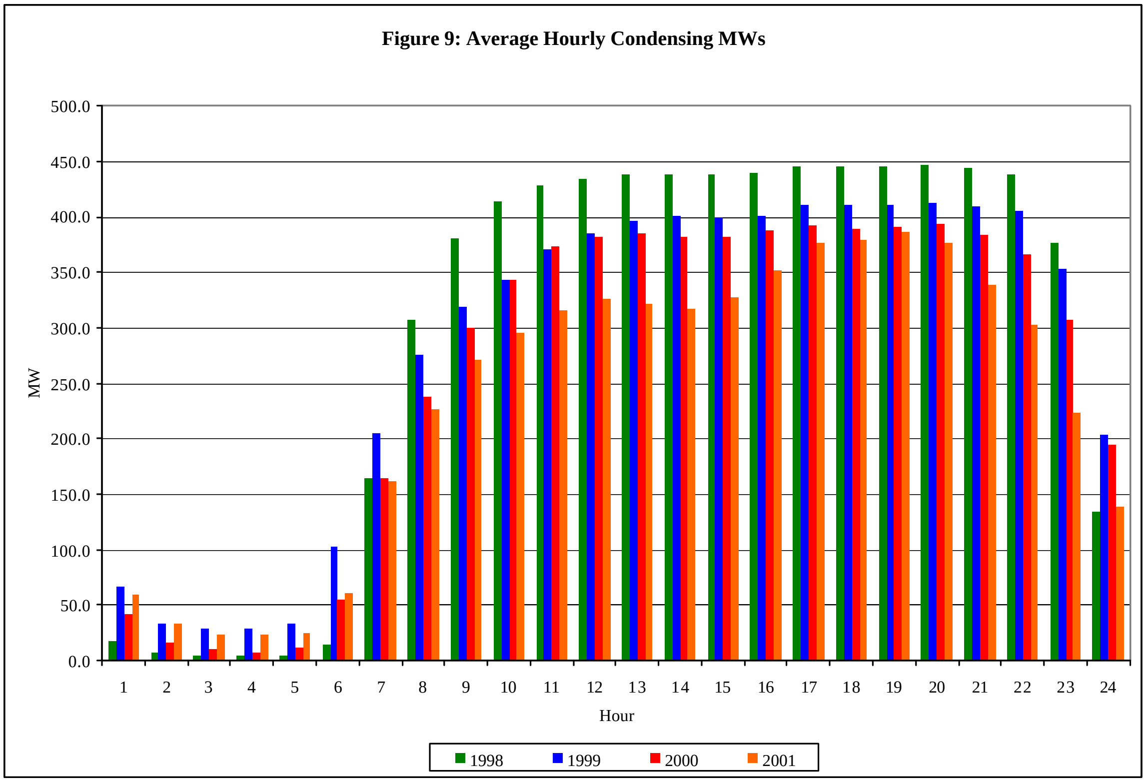


Figure 9: Average Hourly Condensing MWs
MW
500.0
450.0
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
1998
1999
2000
2001

CONGESTION, FTRS AND THE FTR AUCTION MARKET

Summary and Conclusions

Congestion results when units are dispatched out of merit order in order to control loadings on transmission facilities and nodal prices differ as a result.[1] Congestion in PJM increased in 2001 over 2000. Total congestion in 2001 was the result, in part, of relatively high levels of congestion during specific months, which were in turn affected by congestion across facilities which affected large portions of PJM load.

In PJM, Fixed Transmission Rights (FTRs) are available to firm point-to-point and network transmission service customers as a hedge against the congestion charges that can result from PJM's system of locational marginal pricing (LMP). These firm transmission customers have access to FTRs because they pay the costs of the transmission system. Such customers receive FTRs to the extent that they are consistent with the physical capability of the transmission system and consistent with the other requests for FTRs. An FTR is a financial instrument that entitles the holder to receive revenues (or pay charges) based on the hourly LMP differences in the day-ahead market across a specific path. An FTR does not represent a right to physical delivery of power. FTRs can protect transmission service customers, whose day-ahead energy deliveries are consistent with their FTRs, from uncertain costs caused by transmission congestion in the day-ahead market. Transmission customers are hedged against real-time congestion by matching real-time energy schedules with day-ahead energy schedules. FTRs can also provide a hedge for market participants against the basis risk associated with delivering energy from one bus or aggregate to another bus or aggregate. An FTR holder does not need to deliver energy in order to receive congestion credits. FTRs can be purchased with no intent to deliver power on a path.

The initial annual FTR allocation process provided FTRs only to network and firm point-to-point transmission customers and the bilateral market allowed the exchange of only those specific FTRs. The initial FTR allocation process also provided that existing FTRs for network and firm point to point service had priority in subsequent annual FTR allocations. The initial FTRs were simply continued. The network FTRs were actually held by the utilities that were the initial providers of retail service to network customers. Clearly, it would be difficult for an LSE that wished to serve customers in a congested area to compete with an incumbent utility that held FTRs. The new entrant would face the risk of congestion while the incumbent would not. In order to address this issue, PJM modified the FTR allocation process effective June 1, 2001, to eliminate this priority and treat all requests for FTRs identically. The revised process allocated FTRs to network service customers based on annual peak load share rather than on historic priority. The result was to open the access to FTRs to new LSEs that did not have historic FTRs.

The FTR Auction Market was designed to make FTRs more available to market participants by providing a venue for holders of FTRs to sell them and for PJM to make available unsubscribed FTRs.

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[1] Merit order means in order of generator offers from lowest to highest. 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.

The basic mechanics of the FTR auction have worked as intended, since their approval by FERC on April 13, 1999.[2] A review of the operation of the FTR auction process indicates that the FTR auction was competitive and has succeeded in its purpose of increasing access to FTRs. There has been a steady increase in the MW of cleared FTRs. (See Figure 4.) The trends in the number of bids, the number of offers and MW of bids have also been upward. (See Figures 5, 6 and 7.) The increase in the FTR auction clearing prices reflect the prices bid to purchase FTRs which were supplied primarily from PJM residual capacity.

Nonetheless, the results of the FTR allocation process and the FTR auction do not yet result in incumbent retail load servers and potential competitors facing the same level of congestion risk for serving the same customers. For example, if an LSE gains customers from a utility or another LSE after the close of nominations for annual FTRs, there is no automatic process to transfer FTRs with the customers from the utility to the LSE. If the existing utility's load is 100 percent hedged with FTRs and it loses load, then the utility must return the FTRs corresponding to the lost load. The new LSE may request the FTRs. However, if the existing utility is only 80 percent hedged with FTRs and it loses 10 percent of its load, the utility does not need to return any FTRs because its total FTRs are less than its peak load. Thus, the new LSE does not have access to the same level of hedging as the existing utility. PJM is currently developing a method for auctioning all FTRs, while continuing to protect the customers who pay for the transmission system from congestion charges and linking the associated protection from congestion to the end use customers rather than to the incumbent utilities.[3] The FTR allocation method should be modified to eliminate any barriers to retail competition.

Finally, the significant increases in congestion suggest the importance of PJM implementing FERC's Order to develop an approach to identify areas where investments in transmission expansion would relieve congestion where that congestion may enhance generator market power and where such investments are needed to support competition.

History

On November 25, 1997, the Federal Energy Regulatory Commission (FERC) approved the comprehensive restructuring of the PJM marketplace, establishing PJM as an Independent System Operator ("ISO"). [4] In the November 25 Order, the Commission conditionally approved a locational marginal pricing method (LMP) for managing transmission congestion together with the provision of FTRs to firm transmission customers.

As part of the November 25 Order, FERC directed PJM to file a proposal addressing any lack of price certainty that might exist under LMP for transactions not hedged by FTRs. On December 31, 1997, the PJM Supporting Companies[5] filed proposed amendments to Schedule 1 of the

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2 87 FERC ¶61,054 (1999).

3 There is currently disagreement among PJM members regarding the extent to which these are issues and the way in which the issues should be addressed.

4 Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257 (1997) ("November 25 Order").

5 The PJM Supporting Companies were Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, PP&L, Inc., Potomac Electric Power Company and Public Service Electric and Gas Company.

Operating Agreement to implement an FTR auction, which, they concluded, was one way to address the lack of price certainty. On March 25, 1998, PJM filed in support of the FTR auction proposal of the PJM Supporting Companies.

On April 1, 1998, PJM implemented LMP for energy and offered FTRs as a transmission congestion hedging mechanism to all firm transmission service customers. The initial allocation of FTRs was for a 2-month transition period from April 1 through May 31, 1998. The first long-term FTRs were effective for the 1998-1999 Planning Period, June 1, 1998 through May 31, 1999.

The Commission issued an Order on February 11, 1999,[6] rejecting the Supporting Companies' proposal regarding the FTR auction, and directing PJM to develop, with stakeholder input, another FTR auction proposal addressing the Commission's concerns within 90 days. [7]

On March 2, 1999, in compliance with the February 11 Order, PJM made a filing revising the FTR auction proposal. PJM's Members Committee unanimously ratified the revised FTR auction proposal on March 26, 1999.[8] PJM filed revised pages to the PJM Open Access Transmission Tariff (OATT) and Operating Agreement (OA) establishing an FTR auction.[9] On April 13, 1999, the Commission issued an Order conditionally accepting the FTR Auction filing with an effective date of April 13, 1999.[10]

On June 1, 2000, PJM introduced the Two-Settlement System under which there are two energy markets (settlements): a day-ahead and a real-time, or balancing, market. The day-ahead market permits market participants to lock in nodal energy prices one day ahead of real time. Differences between market participants' day-ahead and real-time energy injections and withdrawals are settled in the balancing market at real-time prices. The most significant feature of the Two-Settlement System for FTRs is that transmission congestion is now hedged by FTRs only in the day-ahead market. FTRs are settled at day-ahead energy market prices. Market participants are hedged in real-time to the extent that their energy schedules in the real-time market are consistent with their energy schedules in the day-ahead market.

On July 12, 2001, FERC issued an Order provisionally granting PJM RTO status.[11] In that Order, FERC stated, with respect to congestion, that the transmission planning process "should also focus on identifying projects that expand trading opportunities, better integrate the grid, and alleviate congestion that may enhance generator market power. The PJM ISO planning process appears to be driven more by the particular needs of TOs in serving their traditional retail customers than in fostering competitive markets. Consequently, we will require PJM to modify Schedule 6 to specify an RTO planning process that gives full consideration to all market perspectives and identifies expansions that are critically needed to support competition as well as reliability needs."

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6 86 FERC ¶61,147 (1999).

7 Id. at 61,527.

8 Letter from counsel for PJM dated March 26, 1999.

9 Attachment K-Appendix to the OATT and Schedule 1 of the OA.

10 87 FERC ¶61,054 (1999).

11 96 FERC ¶ 61,061 (2001).

Congestion Accounting

Transmission congestion can exist in both the day-ahead and balancing markets, and total congestion is the sum of the two. Only transmission congestion in the day-ahead market can be directly hedged by using FTRs. Thus, real-time congestion charges can only be hedged 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 are incurred by network customers in delivering their generation to their load, while explicit congestion charges are those incurred by point-to-point transactions.

Implicit congestion charges are equal to 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, for point-to-point transmission transactions, 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 are equal to the difference between total spot market purchase payments and total spot market sale revenues.

Congestion in PJM

Table 1 shows total congestion by year from 1999 through 2001. There was a total of \$271,400,000 in congestion charges on the PJM system during 2001, approximately twice the \$132,000,000 of congestion charges in 2000 which was in turn about two and a half times the level of congestion in 1999. While the details of the congestion in 2001 are presented below, the overall increase in congestion costs can be attributed to different patterns of generation, imports and load and in particular the increased frequency of congestion at PJM's Western Interface which affects about 75 percent of PJM load.

The significant increases in congestion suggest the importance of PJM implementing FERC's Order to develop an approach to identify areas where investments in transmission expansion would relieve congestion that may enhance generator market power and are needed to support competition.

Table 1. Total Congestion	
Year	**($\$10^6$)**
1999	$53
2000	$132
2001	$271

Table 2 lists the monthly congestion charges, FTR target allocations and credits, payout ratios, congestion credit deficiencies, and excess congestion charges by month for 2001. At year-end, excess congestion charges are used to offset any monthly congestion credit deficiencies and these adjustments are shown as a separate line item. Although there were months with congestion credit deficiencies, FTRs were paid at 99% of the target allocation level after the year-end distribution of excess congestion charges. The fact that FTRs in aggregate provided a hedge against 99% of congestion does not mean that all those paying congestion were hedged. The aggregate numbers do not indicate anything about the underlying distribution of FTR holders and those paying congestion.

Table 2. 2001 PJM Congestion Accounting Summary						
Month	**Congestion Charges (10^6)**	**FTR Target Allocations (10^6)**	**Congestion Credits (10^6)**	**FTR Payout Ratio**	**Congestion Credit Deficiency (10^6)**	**Excess Congestion Charges (10^6)**
Jan-01	$9.7	$10.7	$9.7	90%	$1.1	$0.0
Feb-01	$14.2	$26.3	$14.2	54%	$12.1	$0.0
Mar-01	$15.5	$23.4	$15.5	66%	$8.0	$0.0
Apr-01	$7.4	$7.6	$7.4	97%	$0.2	$0.0
May-01	$17.7	$17.4	$17.4	100%	$0.0	$0.3
Jun-01	$30.2	$23.1	$23.1	100%	$0.0	$7.1
Jul-01	$19.8	$23.0	$19.8	86%	$3.2	$0.0
Aug-01	$73.6	$60.1	$60.1	100%	$0.0	$13.4
Sep-01	$28.6	$27.5	$27.5	100%	$0.0	$1.1
Oct-01	$25.5	$30.2	$25.5	84%	$4.7	$0.0
Nov-01	$20.6	$18.5	$18.5	100%	$0.0	$2.1
Dec-01	$8.8	$7.6	$7.6	100%	$0.0	$1.2
Total	$271.4	$275.4	$246.2	89%	$29.3	$25.2
Final 2001 values after distribution of excess congestion charges:						
Total	$271.4	$275.4	$271.4	99%	$3.2	$0.0

Table 3 shows the variation in congestion charges by month, day and hour. As shown, monthly congestion charges varied from a maximum of $73,600,000 in August to a minimum of $7,400,000 in April. August had $43,000,000 more in congestion charges than the next most congested month. Median and mean monthly congestion charges were $16,100,000 and $19,900,000.

Table 3. 2001 Transmission Congestion Revenue Statistics				
Period	**Maximum**	**Mean**	**Median**	**Minimum**
Monthly	$73,600,000	$19,900,000	$16,100,000	$7,400,000
Daily	$27,800,000	$700,000	$375,000	-$12,600,000
Hourly	$5,000,000	$29,400	$8,500	$-2,100,000

The maximum value of daily congestion, $27,800,000, occurred on August 10th, with congestion over $20,000,000 higher than the next highest day. August 10th was the last day of an all time peak load setting heat wave. PJM was operating under the Western Interface constraint. The congestion charges incurred on August 10th were more than were incurred during every month except June, August, and September.

The minimum value of daily congestion, -$12,600,000, occurred on July 25th. PJM was operating under the Eastern and Western Interface constraints. The median of daily congestion charges was $375,000 and the average value was $700,000. Eight of the ten days with the highest congestion charges occurred during the summer. The maximum value of hourly congestion, $5,000,000, occurred during the hour ended 1600 on August 10th. In fact, nine of the ten highest values of hourly congestion all occurred on August 10th for the hours ended 1200 through 2000.

Analysis indicates that during most heavily congested months, the majority of the congestion charges were accrued during just a few days. For example, the five highest congested days during the highest congested month of August accounted for 63% of all congestion charges incurred during the month. Similarly, five days in June and September, the months with the second and third highest congestion charges, had 59% and 50% of all congestion charges incurred during the month.

Table 2 shows that monthly FTR payout ratios averaged about 90% and that February and March accounted for $20,000,000 out of $29,000,000 of all congestion credit deficiencies incurred during the year. These deficiencies were in part the result of unanticipated differences in loop flows between the day-ahead and real-time markets, which were in turn the result of market participants gaming the differences in interface modeling between the PJM and New York markets. PJM had both a New York East and a New York West Interface modeled while the New York ISO had only one PJM interface modeled. Market participants scheduled transactions into New York in the day-ahead market through the PJM-New York West Interface. In real-time the power actually flowed across the PJM Eastern Interface and the PJM-New York East Interface. The difference between real-time and day-ahead flows across the Eastern Interface resulted in congestion in real time because more expensive units were required in the east in real time than in the day ahead market. Load in the east did not change correspondingly and was therefore largely hedged against real time congestion. The result was congestion credits that were not balanced by congestion charges. A new market rule that combined the two New York interfaces into a single interface was implemented, which solved the problem.

Table 4 lists the constraints that ranked in the top 25 for hours of occurrence for 2000 or 2001 and ranked by positive or negative change between the years, sorted by percent of PJM load impacted.[12]

Constraints 1 through 4 in Table 4 comprise the set of constraints that impact more than 50% of PJM load, a set comprised entirely of the primary operating interfaces.[13] The number of congested hours increased between 2000 to 2001 for this group, from 533 to 841 hours, a 308-hour increase, impacting, on average, 70% of PJM load. Congestion increased on the Western and Western Voltage Interfaces by a net 388 hours, increased on the Central Interface by 35 hours, and decreased on the Eastern Interface by 115 hours. The Eastern Interface impacts the 57% of PJM load located in New Jersey, Delaware, Eastern Pennsylvania, and on Maryland's Eastern Shore, while the Central Interface also impacts eastern load, along with an additional 14% of PJM load located in Central Pennsylvania. The Western Interface and Western Voltage Interface constraints impact these areas as well as load in Western Pennsylvania, Washington D.C., and the Baltimore zone. The results presented in Table 4 show that transmission congestion on the main operating interfaces that impact large amounts of PJM load has increased in frequency and moved west, impacting more PJM load more frequently.

Constraints 5 through 7 in Table 4 comprise the set of constraints that impact between 10 and 50% of PJM load. The number of congested hours increased from 14 to 508 hours for this group, a 494-hour increase, impacting, on average, 16% of PJM load. Congestion increased on all facilities within the group, especially on the Keeney transformers, which impacts 25% of PJM load and is the most severe constraint within the group.

Constraints 8 through 10 in Table 4 comprise the set of constraints that impact between 5 and 10% of PJM load. The number of congested hours remained nearly constant, increasing 15 hours from 615 to 630 hours for this group, impacting, on average, 7% of PJM load. All three of these constraints are located in Northern PSEG.

The remaining constraints 11 through 43 comprise the set of constraints that impact less than 5% of PJM load. The number of congested hours increased from 4,317 to 5,907 hours for this group, a 1,590-hour increase, impacting, on average, 1% of PJM load. Twenty-one of these thirty-three constraints are 69 kV, eleven are 115 and 138 kV, and one 230 kV operating voltages. The Mount Olive-Piney Grove 69 constraint was the most frequent, in effect for 1,559 hours or nearly 20% of all hours.

The transmission reinforcements installed on the Delmarva Peninsula during 2000 reduced certain instances of congestion. The Southern DPL voltage constraint (constraint 14 in Table 4) was not encountered during 2001, a 229-hour decrease from year 2000. Other Delmarva Peninsula constraints that were effectively eliminated during 2001 were Vienna-Vienna Local (-115 hours), Kings Creek-Loretto (-157 hours), Centerville-Wye Mills (-201 hours), Easton-Trappe (-438 hours), and Oak Hall-Tasley (-502 hours), all 69 kV lines.

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12 The constrained hour data presented here use the convention that if congestion occurs in an hour, the hour is considered congested.

13 The percent of load impacted, as presented in Table 4, is an approximation.

Table 4. Constraint Duration Summary								
		Percent of PJM Load	Constrained Hours			Percent of Hours		
#	Constraint	Impacted	2000	2001	Change	2000	2001	Change
1	Western Interface	75%	77	493	416	1%	6%	5%
2	West Volt Interface	75%	111	83	-28	1%	1%	0%
3	Central Interface	70%	0	35	35	4%	3%	-1%
4	Eastern Interface	57%	345	227	-115	4%	3%	-1%
5	Keeney 500/230	25%	14	326	312	0%	4%	4%
6	Whitpain 500/230	14%	0	58	58	0%	1%	1%
7	Branchburg – Flagtown 230	10%	0	124	124	0%	1%	1%
8	Cedargrove – Roseland 230	9%	494	378	-20	6%	5%	0%
9	Cedargrove – Clifton 230	7%	18	118	102	0%	1%	1%
10	Bayonne - PVSC 138	5%	103	36	-67	1%	0%	-1%
11	Churchtown 230/69	3%	0	199	199	0%	2%	2%
12	Cumberland 230/138	3%	7	70	63	0%	1%	1%
13	Monroe 230/69	3%	22	181	159	0%	2%	2%
14	DPL South Interface	3%	229	0	-229	3%	0%	-3%
15	Erie West 345/115	2%	447	670	223	5%	8%	3%
16	Hunterstown 230/115	2%	40	223	183	0%	3%	2%
17	Jackson 230/115	2%	0	199	173	0%	2%	2%
18	Edison - Meadow Rd. 138	2%	170	242	61	2%	3%	1%
19	Talbot - Trappe TP 69	2%	116	43	-73	1%	0%	-1%
20	Brunswick – Edison 138	2%	175	82	-93	2%	1%	-1%
21	Plainsboro – Trenton 138	2%	95	1	-94	1%	0%	-1%
22	Mt. Olive - Piney Grove 69	1%	137	1559	1422	2%	18%	16%
23	Shield Alloy – Vineland 69	1%	11	389	378	0%	4%	4%
24	Hallwood - Oak Hall 69	1%	231	532	301	3%	6%	3%
25	Cedars - Motts 69	1%	187	475	288	2%	5%	3%
26	Laurel – Woodstown 69	1%	3	151	148	0%	2%	2%
27	Greenwood - S.Harrington 69	1%	21	126	105	0%	1%	1%
28	Bridgeview – Greenwood 69	1%	4	108	104	0%	1%	1%
29	Milford - S.Harrington 138	1%	2	95	93	0%	1%	1%
30	Indian River 230/115	1%	23	102	79	0%	1%	1%
31	Mt. Hermon - N. Salisbury 69	1%	73	146	73	1%	2%	1%
32	Beckett – Paulsboro 69	1%	0	58	58	0%	1%	1%
33	Cheswold 138/69	1%	137	144	7	2%	2%	0%
34	Oakhall – Pocomoke 69	1%	88	19	-69	1%	0%	-1%
35	Loretto - Vienna 138	1%	98	0	-98	1%	0%	-1%
36	Lewis - Motts 69	1%	118	13	-105	1%	0%	-1%
37	Vienna - Vienna Local 69	1%	115	0	-115	1%	0%	-1%
38	Kings Creek – Loretto 69	1%	182	25	-157	2%	0%	-2%
39	Cly - Collins 115	1%	232	38	-194	3%	0%	-2%
40	Centreview – Wyemills 69	1%	201	0	-201	2%	0%	-2%
41	Towanda Interface	1%	213	0	-213	2%	0%	-2%
42	Easton - Trappe 69	1%	438	0	-438	5%	0%	-5%
43	Oakhall - Tasley 69	1%	502	0	-502	6%	0%	-6%

However, there are still many local constraints on the Peninsula, especially Mt. Olive-Piney Grove 69, which was constrained during 1559 hours, 18% of all hours, that frequently affect smaller, local load pockets. Other frequently occurring 69 kV Peninsula constraints are Hallwood-Oak Hall, 532 hours, Mt. Hermon-N.Salisbury, 146 hours, Cheswold 138/69, 144 hours, Greenwood-S. Harrington, 126 hours, and Bridgeview-Greenwood, 108 hours.

Congestion Details

As shown in the summary data of Table 5, there were 8,227 congestion-event hours during 2001, a 17% increase from the 7,040 hours in 2000. A congestion event exists when a unit or units must be dispatched off cost in order to control the impact of a contingency on a monitored facility or to control an actual overload. There were 147 different monitored facilities on which congestion occurred, a decrease of 38. This does not mean that the system was constrained 8,227 hours because constraints are frequently simultaneous. While Table 4 presents data on individual circuit elements, Table 5 presents summary data by facility type, voltage class and location. For example, Table 4 lists the individual constraints Cedargrove – Roseland and Cedargrove – Clifton, while Table 5 lists Cedar Grove which includes these two facilities and any others in the Cedar Grove area.

Table 5. Constraint Event Summary, by Facility Type, Voltage Class, and Location.										
		Voltage	Congestion Event Hours				Percent of Congestion Event Hours			
Locale	**Facility**	**(kV)**	**1998**	**1999**	**2000**	**2001**	**1998**	**1999**	**2000**	**2001**
			1244	2134	7040	8227	100%	100%	100%	100%
	Line		1002	1383	4984	4847	81%	65%	71%	59%
	Transfrmr		225	345	1017	2530	18%	16%	14%	31%
	Interface		17	406	1039	850	1%	19%	15%	10%
		69		147	2826	2697		7%	40%	33%
		230	588	818	1461	2317	47%	38%	21%	28%
		500	203	189	684	1326	16%	9%	10%	16%
		138	365	819	1045	797	29%	38%	15%	10%
		345	71	148	491	725	6%	7%	7%	9%
		115	17	13	528	365	1%	1%	8%	4%
		34			5				0%	
	Line	69		147	2762	2691		7%	39%	33%
	Line	230	540	454	1008	1324	43%	21%	14%	16%
	Transfrmr	230	48	104	224	993	4%	5%	3%	12%
	Interface	500	17	146	533	844	1%	7%	8%	10%
	Transfrmr	345	57	146	475	675	5%	7%	7%	8%
	Line	138	362	767	869	580	29%	36%	12%	7%
	Transfrmr	500	117	43	142	472	9%	2%	2%	6%
	Transfrmr	138	3	52	176	217	0%	2%	3%	3%
	Line	115	17	13	315	192	1%	1%	4%	2%
	Transfrmr	115				173				2%
	Line	345	14	2	16	50	1%	0%	0%	1%
	Line	500	69		9	10	6%		0%	0%
	Interface	69			64	6			1%	0%
	Line	34			5				0%	
	Interface	115			213				3%	
	Interface	230		260	229			12%	3%	
Erie			5	118	447	670	0%	6%	6%	8%
Hallwood				21	231	532		1%	3%	6%
Cedar Grove			361	188	515	496	29%	9%	7%	6%
Cedar					192	495			3%	6%
PJM West Interface				50	77	493		2%	1%	6%
Mt. Olive					137	1557			2%	19%
Shield Alloy					11	389			0%	5%
Keeney			5		14	326	0%		0%	4%
Edison			174	24	170	242	14%	1%	2%	3%
PJM Eastern Interface			17	73	345	227	1%	3%	5%	3%
Branchburg			41	11	52	224	3%	1%	1%	3%
Hunterstown				9	40	223		0%	1%	3%
Churchtown						199				2%
Jackson (ME Zone)						199				2%
Monroe					22	181			0%	2%
Cheswold				39	139	151		2%	2%	2%
Laurel					3	151			0%	2%
Mt. Hermon					73	146			1%	2%
Greenwood					21	126			0%	2%
Bridgeville				7	4	108		0%	0%	1%
Indian River				10	59	102		0%	1%	1%

Figure 1 provides congestion subtotals by facility type: line, transformer, and interface. As shown, transmission line and transformer thermal limits have historically accounted for about 70% and 20% of all congestion hours, while interface constraints have averaged about 10% of all constraints since the inception of the FTR market.

Figure 1
Constrained Hours as Percent of Total by Facility Type

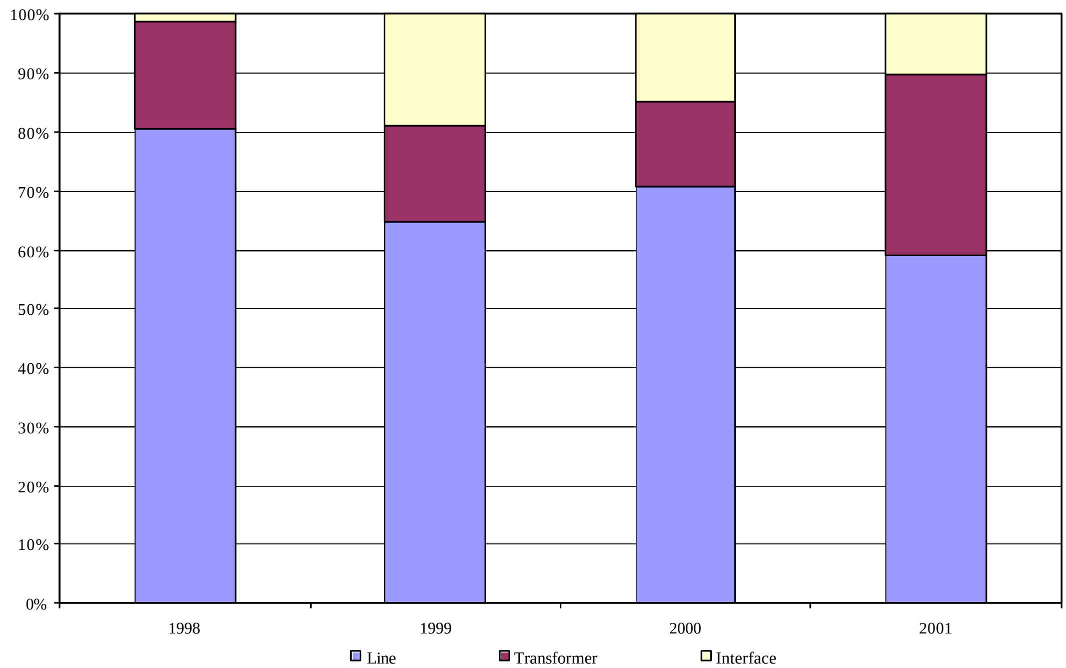
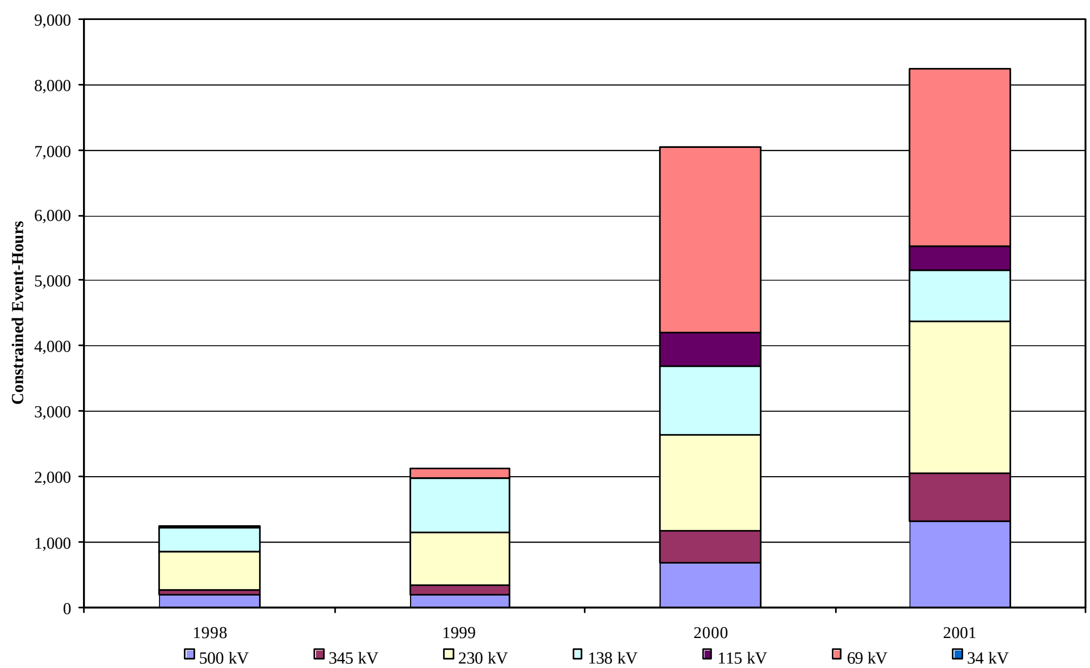


Figure 2 provides congestion hour subtotals by facility voltage class. As shown, constrained hours have increased over all voltage classes. There has been a notable increase in constraints on lower-voltage facilities, i.e., operating voltage less than or equal to 115 kV, which have increased from 17 in 1998 to over 3,000 constraint-hours in 2000 and 2001. These data indicate that there is an increased occurrence of local constraints that generally affect smaller load pockets. The increased hours of constraints on lower voltage portions of the transmission system means that there is more visible congestion but does not necessarily mean that there is more actual congestion on these facilities, although that may be the case. Transmission owners have requested, pursuant to the PJM Operating Agreement, that PJM assume monitoring and control of lower voltage facilities. This in turn has resulted in more visible constrained hours as PJM controls for congestion on the facilities by redispatching generation which, in turn, creates LMP differentials. This phenomenon has been especially notable on the Delmarva Peninsula where the number of constrained hours on lower-voltage facilities increased markedly after PJM assumed control of these facilities in the latter half of 1999. Prior to PJM control, congestion was controlled by the local integrated utility which, in some cases, ran additional generation equipment as required but did not affect LMP.

Figure 2. Constrained Hours by Facility Voltage



PJM FTR Mechanics

Each FTR is defined from a point of receipt, where power is injected into the grid, to a point of delivery, where the power is withdrawn from the grid.[14] Each FTR has two key dimensions, direction, as defined by the injection and withdrawal points, and MW level. For each hour during which congestion occurs on the transmission system and the FTR is in the same direction as the congested flow, the FTR holder receives a share of the transmission congestion charges collected from market participants. This share is the participant's transmission congestion credit. Credits are paid to all FTR holders, for paths with positive LMP differentials, regardless of who delivered energy or how much energy was delivered across the constrained path. FTR holders pay a charge if the FTR is in the direction opposite to the congested flow.

An FTR can provide financial benefits or liabilities. An FTR provides a benefit when the path designated in the FTR is in the same direction as the congested flow, i.e., the LMP at the point of withdrawal is higher than the LMP at the point of injection. The value of the FTR is equal to the FTR MW reservation times the (positive) difference between the LMP at the point of withdrawal and the LMP at the point of injection. An FTR can be a liability when the designated path is in the direction opposite to the congested flow, i.e. the LMP at the point of withdrawal is lower than the LMP at the point of injection. In this case, the value of the FTR is equal to the FTR MW reservation times the (negative) difference between the LMP at the point of withdrawal and the LMP at the point of injection. In either case, an FTR holder that delivers energy on the designated path consistent with the FTR would either receive FTR revenues or make FTR payments equal to congestion charges or congestion credits. The result would be no net congestion-related benefits or liabilities.

If FTRs were a perfect hedge, each FTR holder would receive a credit equal to its FTR MW reservation multiplied by the LMP difference between the point of delivery and the point of receipt of their FTR, when constraints exist on the transmission system. This is termed the transmission credit target allocation. FTRs are not necessarily a perfect hedge and in fact FTRs have hedged from 98 percent to 99 percent of congestion costs.

PJM time-stamps and processes all FTR requests in the order in which they are received. PJM approves FTRs based on the results of the Simultaneous Feasibility Test, and market participants must confirm approved FTRs for them to become effective.

Simultaneous Feasibility Test

The Simultaneous Feasibility Test (SFT) is a market feasibility test that attempts to ensure that the physical transmission system can support the subscribed set of FTRs during expected system conditions. The SFT attempts to ensure that the MW levels of FTRs will actually be deliverable without congestion. In other words, the intent of the SFT is to ensure that no more hedges against congestion are sold than are expected be actually available. One important result of selling only feasible FTRs is that it preserves the financial value of the FTRs. In other words, it preserves revenue adequacy, which means that each FTR holder will actually be paid the value of congestion on a path. If an FTR passes the Simultaneous Feasibility Test, it is considered feasible and may be awarded. If congestion occurs and actual system conditions at the time of the congestion are consistent with the system conditions expected when the FTRs were allocated,

[14] Point of injection and withdrawal refers to one or more buses.

PJM will collect sufficient revenues through congestion charges to cover the FTR congestion credits payable to the holders of FTRs, and revenue adequacy will exist. The primary purpose of the Simultaneous Feasibility Test is to preserve the economic value of FTRs by attempting to ensure that all FTRs awarded can be fully funded.[15]

FTR Values

Tables 6a and 6b include FTR target allocations for the highest value transmission paths, measured by target allocations, from the auction for January 2001 through the auction in December. FTR target allocations represent the amount of FTR revenues needed to fully hedge FTR holders against congestion. During this period FTR target allocations totaled $246,000,000 on approximately 2,500 different transmission paths.

Table 6a. FTR Target Allocations by Path, Twenty-Five Largest Financial Benefit

Path	Target Allocations
Peach Bottom – PSEG Zone	$22,720,584
Edgemoor – DPL Zone	$17,049,472
Peach Bottom – PECO Zone	$10,487,243
Chalk Point – AECO Zone	$8,267,927
Mercer – PSEG Zone	$7,539,744
Conemaugh – PSEG Zone	$7,365,041
Keystone – PSEG Zone	$7,243,532
Martins Creek – PSEG Zone	$6,332,172
Burlington – PSEG Zone	$5,752,824
TMI – Penelec Zone	$4,721,133
Vienna – Kings Creek	$4,573,064
Crane – DPL Zone	$4,461,192
Conemaugh – PECO Zone	$4,455,583
Keystone – PECO Zone	$4,284,090
Yards Creek – PSEG Zone	$4,247,340
Muddy Run – PECO Zone	$3,932,111
Susquehanna – DPL Zone	$3,809,585
Limerick – PECO Zone	$3,231,341
Perryman – DPL Zone	$3,181,845
Chambers – AECO Zone	$2,968,588
Riverside – DPL Zone	$2,778,789
Bridgeport – AECO Zone	$2,686,748
Susquehanna – AECO Zone	$2,138,675
Vienna – Oakhall	$2,134,601
Crane – DPL ODEC	$1,669,193
TOTALS	$148,032,418

Table 6b. FTR Target Allocations by Path, Twenty-Five Largest Financial Liability

Path	Target Allocations
Kings Creek – DPL Zone	($961,840)
Homer City – JCPL Zone	($960,031)
Cedar – DPL Zone	($691,785)
Hallwood – Newberry	($591,735)
NYPP-E – Springboro	($568,589)
Aldene – Susquehanna	($478,468)
PSEG Zone – JCPL Zone	($414,683)
Salem – PECO Zone	($412,794)
Homer City – Meted Zone	($390,912)
NYPP-E – Western Hub	($380,858)
Indian River – Harrington	($374,063)
Warren – Penelec Zone	($371,381)
AP – PEPCO Zone	($350,620)
TMI – JCPL Zone	($320,962)
Essex – Rolling Meadows	($315,543)
Dumont – PEPCO Zone	($270,571)
Salem – Franklin	($251,093)
NYPP-E – Erie West	($245,017)
Western Hub – ECAR	($214,341)
NYPP-W – Penelec Zone	($205,286)
Western Hub – PPL Zone	($179,747)
Facerock – PPL Zone	($176,787)
Hudson – Conemaugh	($168,083)
NYYP-W – Western Hub	($158,235)
Susquehanna – JCPL Zone	($149,122)
TOTALS	($9,602,546)

15 PJM Manual for Fixed Transmission Rights, Manual M-06.

Table 6a lists the twenty-five FTRs with the largest financial benefits for the period. These FTRs account for over $148,000,000, or 65 percent, of the total target allocations. Most of these are from sources in Western and Central Pennsylvania to destinations in Eastern PJM, such as the PSEG, PECO, DPL, and AECO zones. The top 3 FTRs maintain their ranking from last year, as do 7 of the top 10 and 14 of the top 25 FTRs.

Table 6b lists the twenty-five FTR paths with the largest financial liabilities over the same period. These FTRs account for about $9,600,000, or 18 percent, of the $53,000,000 negative target allocations. There is no clear directional pattern for these FTRs. Some are east-to-west, others are west-to-east, while others are local. Only 6 of the top 25 FTRs with negative values maintain their top 25 ranking from last year, while 10 of the 25 were of an east-to-west direction.

Acquisition of FTRs

As noted earlier, there are four ways to acquire FTRs:

- Network Integration Service
- Firm Point-to-Point Service
- Bilateral FTR Market
- FTR Auction

FTRs can be obtained together with Network Integration Service and Firm Transmission Service. The Bilateral Market and the FTR Auction allow trading of existing FTRs, regardless of how the FTRs were acquired.

Network Integration Service FTRs

Network customers may select FTRs from any combination of their network resources to their network load in an amount up to their total peak load, and are free to add or drop FTRs at any time, subject to the Simultaneous Feasibility Test. PJM permits changes to the designation of network resources and loads at any time, subject to the Simultaneous Feasibility Test. Network FTRs are designated along paths from the specific, selected capacity resources, or the interconnection point with an external control area, to customers' aggregate loads. The generators selected for FTRs, which must be capacity resources, are referred to as designated network resources.[16]

FTRs are determined to be feasible from a capacity resource to a particular company's aggregate load. However, the FTRs from this specific capacity resource may not be feasible to a different company's aggregate load and therefore cannot be automatically reconfigured. As a result, FTRs associated with specific capacity resources cannot be directly transferred to meet a different company's aggregate load. In general, buyers of FTRs must request the FTRs subject to the Simultaneous Feasibility Test. In order to establish feasibility, FTRs associated with capacity sales are available to the buyer only if the specific generating units and capacity amounts are identified. FTRs cannot be obtained for capacity credit transactions.

16 See Capacity Markets section for a definition of capacity resource.

Firm Point-to-Point Service FTRs

PJM members may obtain FTRs with firm point-to-point transmission service, and may request FTRs up to the amount of their transmission service. As in the case of network service, PJM approves all, part, or none of any FTR request based on the results of the Simultaneous Feasibility Test. The FTRs remain in effect for the duration of the transmission service, which may be one year, one month, one week, or one day. Table 7, Transmission Service and FTR Request and Approval Timeline, details the required lead and response times and maximum terms for point-to-point service requests and FTRs.

Firm point-to-point transmission service is generally used in PJM for transmission out of PJM or through PJM. The associated FTRs are for the transmission path specified in the transmission reservation. The point of injection (receipt) may be, for example, a generation resource within the PJM Control Area or the interconnection point with an external control area. The point of withdrawal (delivery) may be, for example, one of the PJM aggregates or the point of interconnection with an external control area.

Table 7.
Transmission Service and FTR Request and Approval Timeline

Event	**Annual**	**Monthly**	**Weekly**	**Daily**
Earliest Request	No Limit	18-months	2-weeks	3-days
Latest Request	2-months	14-days	7-days	2-days
OI Respond	1-month	Per tariff	2-days	4-hours
Customer Confirm	15-days after PJM approves OR By 12 noon on day before service starts			
Maximum Term	No Limit	1-month	2-weeks	2-days

Bilateral Market FTRs

FTRs may be traded among buyers and sellers on the secondary market. Such bilateral trades can be made using PJM's eFTR trading system or they can be made independent of PJM's system. The data here reflect only those bilateral trades made using PJM's system.[17] Table 8 shows that a total of 4,349 MW of FTRs were traded in 35 separate transactions during the period from June 1, 1999 to May 31, 2000, while 4,501 MW of FTRs were traded in 42 transactions period from June 1, 2000 to May 31, 2001. Ninety-eight percent (98%) of the second half trades were continuations of the first-half trades, and 92% of all bilateral transactions were trades between affiliates.

[17] PJM does not track bilateral FTR trades made outside its system.

Table 8. Bilateral Market Statistics By Period			
FTR Contract Period	**Sum (MW)**	**Count**	**Average (MW)**
June 1, 1999 - May 31, 2000	4349	35	124
June 1, 2000 - May 31, 2001	4501	42	107
June 1, 2001 - December 31, 2001	2499	38	66

Monthly Auction FTRs

PJM conducts a monthly auction of both FTRs associated with the residual capability of the PJM transmission system and FTRs offered by market participants. The residual capability of the transmission system is that remaining after network and firm point to point transmission FTRs have been awarded. PJM members and transmission customers may participate in the FTR auction.

Each monthly auction is comprised of both an on-peak and an off-peak auction. The on-peak auction is for FTRs that are valid for hours ending 0800 to 2300 on weekdays, while off-peak FTRs are valid for hours ending 2400 to 0700 on weekdays and all weekend and NERC holiday hours. All auction FTR contracts are for a period of one month.

Auction FTRs may be obtained between single buses, between a single bus and a combination of buses for which an LMP is calculated and posted or between such combinations of buses, subject to the Simultaneous Feasibility Test. These combinations of buses include hubs, zones, aggregates, and single buses either internal or external to PJM. Auction FTRs may be designated between any injection and withdrawal points.

Table 9, FTR Auction Timeline, details the timing of key events in the FTR auction. As indicated, the auction bidding period opens fifteen days prior to the effective date of the transmission rights being auctioned. PJM calculates and posts estimates of non-simultaneous, available FTR capability for the PJM operating and external interfaces. The bids undergo pre-processing where they are verified for proper syntax and the ownership of sell offers is verified. Rejected bids are sent back to the owner for correction and resubmittal.

Table 9. FTR Auction Timeline	
Time	**Activity**
15-days Prior to FTR Period	Bidding Period Opens
10-days Prior to FTR Period	Bidding Period Closes
2-days After Bidding Period Closes	Market is Cleared and Results Posted

Bidding closes ten business days prior to the start date of the period for which the FTRs were auctioned. The auction analysis determines a new set of feasible FTRs by calculating a market-clearing price for every location in PJM and then selecting the highest valued (bid-based) combination of feasible FTR paths. The value of an FTR path is the difference between the source and sink market clearing prices. Buy bids which have prices above the clearing price pay the path clearing price and sell offers which have prices below the path clearing price receive the path clearing price. The winning set of bids is the simultaneously feasible set of FTRs that maximizes the value of the awarded FTRs to the buyers.

The auction solution includes residual system capability plus FTRs offered into the auction. The auction solution does not attempt to match buy and sell offers on particular paths. FTRs offered for sale on particular paths can make additional FTRs available on different, seemingly unrelated paths. Such reconfiguration of FTRs can change the total amount of FTRs available and make available a different, previously infeasible set of FTRs. As a result, buyers can buy FTRs which are different from the FTRs explicitly offered by sellers. Conversely, certain FTRs offered for sale may not clear because they would introduce an infeasible condition.

After the auction is completed, successful bids are loaded into the FTR auction database and transferred to the PJM accounting and billing systems. Winning bids are posted in publicly available files on eFTR, PJM’s internet-based FTR auction management system, no later than two days after the bidding period closes, and all bids are posted after six months. Buyers and sellers settle at path clearing prices for the FTRs they acquire or sell. This settlement is separate from the transmission congestion settlements. Auction revenues, net of payments made to the FTR sellers, are allocated among the regional transmission owners in proportion to their respective transmission revenue requirements.

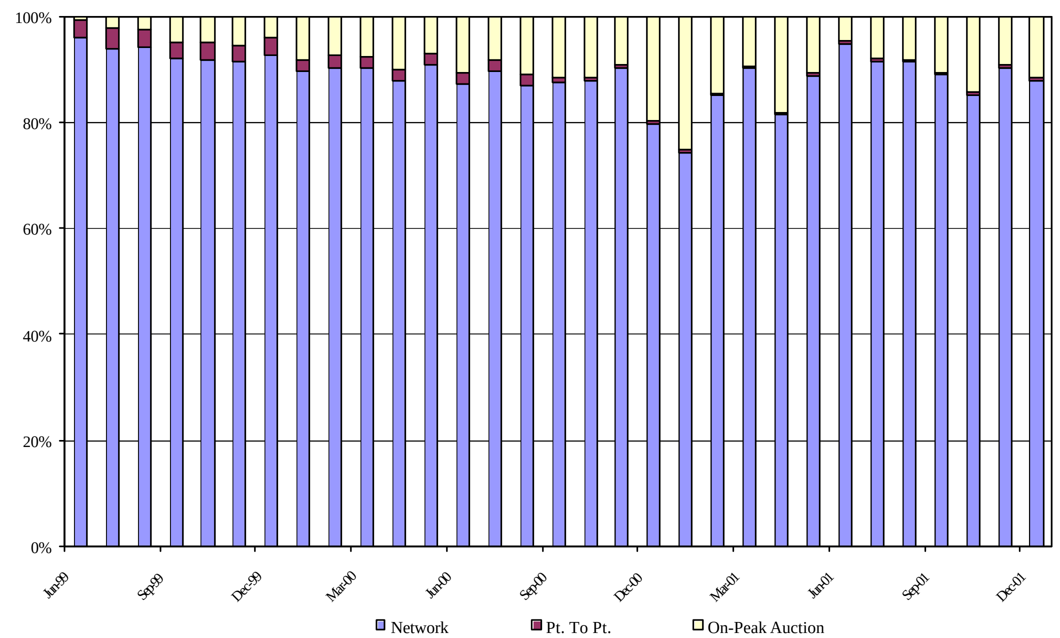
Results of the FTR Auction

As noted earlier, the FTR Auction was designed to increase the availability of FTRs to interested bidders. The auction has worked as intended, was competitive and has succeeded in increasing the availability of FTRs. Auction activity has increased steadily since the inception of the auction as shown by the data in Table 5 and Figures 3 to 13 below.

Table 10 presents data on FTRs by type. The data show that auction FTRs increased from an average of 3% of all FTRs in 1999 to 10% in 2000 and 12% in 2001. In the January 2001 Auction 8,396 MW of FTRs cleared, about 25% of all FTRs for the month. About 13% of FTRs were traded on the secondary FTR market. As shown in Figure 3, network FTRs comprise about 90% of all FTRs since market inception and about 88% for 2001. Point-to-point FTRs represent about 2% of all FTRs.

Table 10. FTRs by Service Type									
	FTRs				Percent of Total			FTRs	%Total
Period	Network	Pt. To Pt.	On-Peak Auction	Total (MW)	Network (%)	Pt. To Pt. (%)	On-Peak Auction (%)	Secondary (MW)	Secondary (%)
May-99	30,684	607	357	31,648	97%	2%	1%	-	0%
Jun-99	29,808	1,107	184	31,099	96%	4%	1%	4,349	14%
Jul-99	28,058	1,107	708	29,873	94%	4%	2%	4,349	15%
Aug-99	32,144	1,107	873	34,124	94%	3%	3%	4,349	13%
Sep-99	32,144	1,107	1,721	34,972	92%	3%	5%	4,349	12%
Oct-99	31,550	1,107	1,729	34,386	92%	3%	5%	4,349	13%
Nov-99	31,178	1,107	1,874	34,159	91%	3%	5%	4,349	13%
Dec-99	31,178	1,107	1,332	33,617	93%	3%	4%	4,349	13%
Jan-00	30,936	750	2,817	34,503	90%	2%	8%	4,349	13%
Feb-00	30,936	750	2,567	34,253	90%	2%	7%	4,349	13%
Mar-00	30,936	750	2,585	34,271	90%	2%	8%	4,349	13%
Apr-00	30,936	750	3,565	35,251	88%	2%	10%	4,349	12%
May-00	30,981	750	2,396	34,127	91%	2%	7%	4,349	13%
Jun-00	30,213	750	3,752	34,715	87%	2%	11%	4,501	13%
Jul-00	29,916	750	2,718	33,384	90%	2%	8%	4,501	13%
Aug-00	30,053	750	3,838	34,641	87%	2%	11%	4,501	13%
Sep-00	30,038	250	4,026	34,314	88%	1%	12%	4,501	13%
Oct-00	30,038	250	3,966	34,254	88%	1%	12%	4,501	13%
Nov-00	29,655	250	3,017	32,922	90%	1%	9%	4,501	14%
Dec-00	29,655	250	7,311	37,216	80%	1%	20%	4,501	12%
Jan-01	24,620	150	8,396	33,166	74%	0%	25%	4,501	14%
Feb-01	28,986	150	4,950	34,086	85%	0%	15%	4,501	13%
Mar-01	29,062	150	3,021	32,233	90%	0%	9%	4,501	14%
Apr-01	29,019	150	6,464	35,633	81%	0%	18%	4,501	13%
May-01	29,018	150	3,528	32,696	89%	0%	11%	4,501	14%
Jun-01	23,497	150	1,131	24,778	95%	1%	5%	2,491	10%
Jul-01	23,497	150	2,083	25,730	91%	1%	8%	2,499	10%
Aug-01	23,497	150	2,097	25,744	91%	1%	8%	2,499	10%
Sep-01	23,497	150	2,788	26,435	89%	1%	11%	2,499	9%
Oct-01	22,341	150	3,776	26,267	85%	1%	14%	2,499	10%
Nov-01	22,197	150	2,233	24,580	90%	1%	9%	2,499	10%
Dec-01	22,234	150	2,923	25,307	88%	1%	12%	2,499	10%
1999 Mean	30,843	1,045	1,097	32,985	94%	3%	3%	3,805	12%
2000 Mean	30,358	583	3,547	34,488	88%	2%	10%	4,438	13%
2001 Mean	25,122	150	3,616	28,888	87%	1%	13%	3,332	12%
Overall Mean	28,516	536	2,960	32,012	89%	2%	9%	3,865	12%

Figure 3.
FTRs as Percentage of Total by Service Type



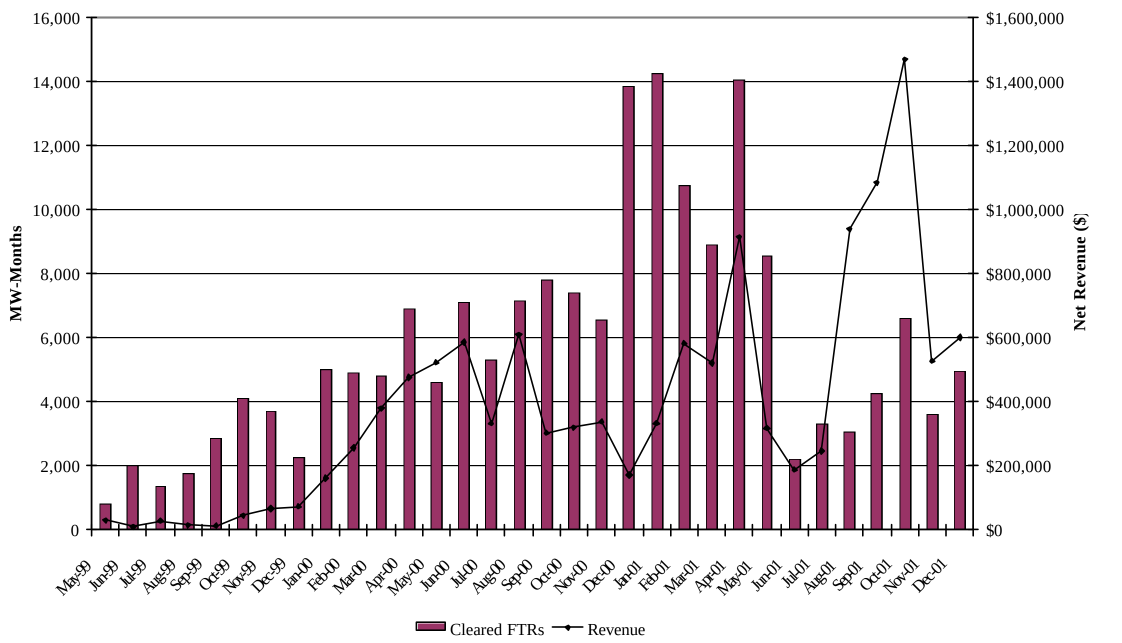
It is usually assumed that a cleared FTR buy bid reduces available FTRs and that a cleared FTR sell offer increases available FTRs, but neither is always correct. For example, when an interface is constrained west-to-east, both a west-to-east FTR sell offer and an east-to-west buy bid would make more FTRs available in the direction of congestion.

In the MMU's FTR Auction Report covering the first year of the FTR auction, all buy bids were categorized as purchases regardless of whether the buy bid was in the same direction as the congested flow or in the opposite direction.[18] The data in Table 10 reflect this convention. However, in the figures in this report, bids and offers are categorized as buys or sells based on whether they are in the same direction as the congested flow or in the opposite direction.

18 Report to the Federal Energy Regulatory Commission: FTR Auction, PJM Market Monitoring Unit, August 1, 2000.

Figure 4, FTR Monthly Auction Volume and Net Revenue, depicts the total cleared bid and offer volume in MW-months together with the total auction revenue generated each month. Average auction revenue increased from $30,000/month in 1999, to $371,000/month in 2000, to $644,000/month in 2001, while the total cleared bid and offer volume increased from 2,300 MW-months in 1999 to 6,700 MW-months in 2000, and 7,000 MW-month in 2001. Revenue increased during the second half of 2001, while cleared volume decreased. As of December 31, 2001, $12,000,000 of net revenue has been produced by the FTR Monthly Auction and distributed to transmission owners.

Figure 4
FTR Monthly Auction Volume Cleared and Net Revenue



As shown in Figure 5, FTR Monthly Auction Activity, the number of buy bids increased steadily until April 2000, when a substantial increase occurred, from an average of 260 bids per month for the prior period to about 2,000 bids per month through the end of 2000. Another increase occurred in 2001 where the average number of bids per month rose to about 7,500. The number of sell offers has consistently been extremely low during most of the auction's existence, averaging only 21 offers per month from May 1999 through December 2001, including zero offers from May 2000 through August 2001.

The increased average buy bid clearing price during the second half of 2001 is consistent with the increased revenue and reduced volume of cleared bids shown in Figure 4. The increased average bid clearing price reflected the underlying fundamentals, that is the underlying increase in the level of congestion and thus the increase in the value of FTRs.

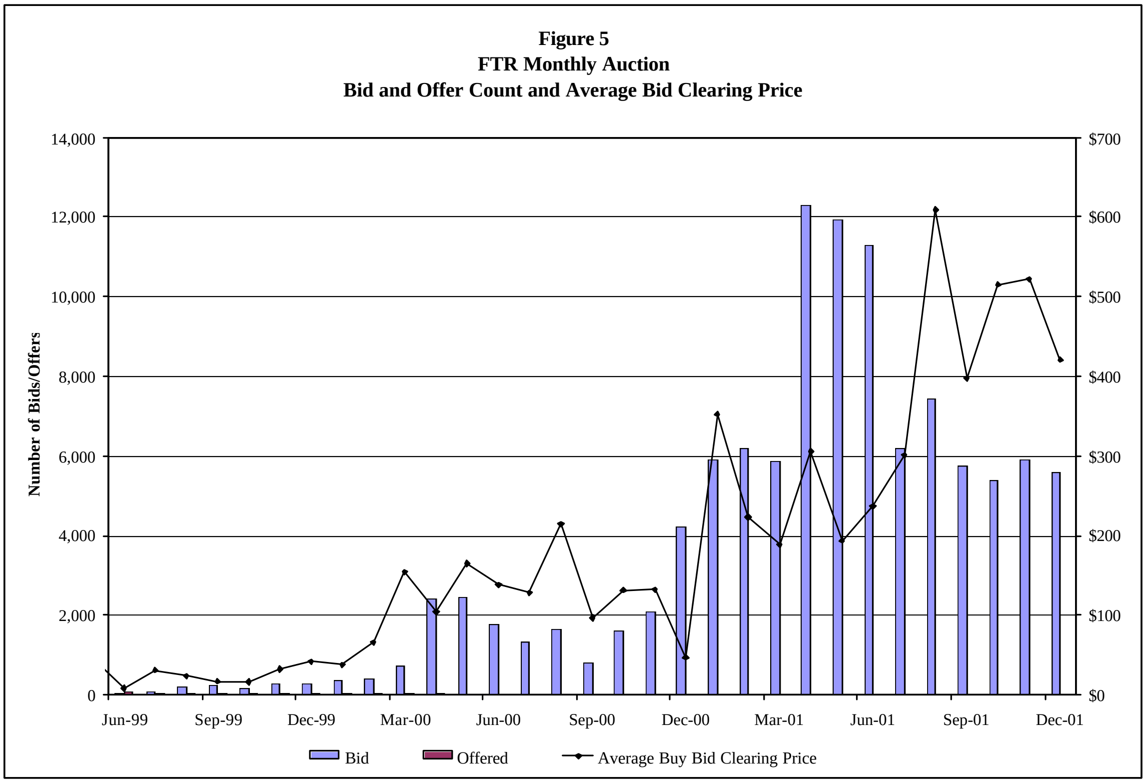


Figure 6, Bid and Offer Volume, presents the MW volume of the submitted and cleared bids and offers. Monthly bid volume increased from nearly 6,000 MW in 1999 to 35,000 MW in 2000, and 78,000 MW in 2001, while offer volume decreased from 8,300 MW in 1999 to 1,600 MW in 2000 and 172 MW in 2001. A significant increase in MW bids occurred during the fourth quarter of 2000. This increase was maintained through 2001 with bid volume averaging about 78,000 MW in 2001, more than twice the average for 2000. Cleared bid volume increased from about 2,000 MW in 1999 to 6,700 in 2000 and 6,900 MW in 2001, while cleared offers averaged 342 MW in 1999, 39 MW in 2000 and 111 MW in 2001. Over the life of the auction, cleared bids exceed cleared offers by 5,500 MW per month on average. Overall, cleared FTR bids are primarily supplied from residual system capability rather than FTR offers.

Figure 6
FTR Monthly Auction Bid and Offer Volume

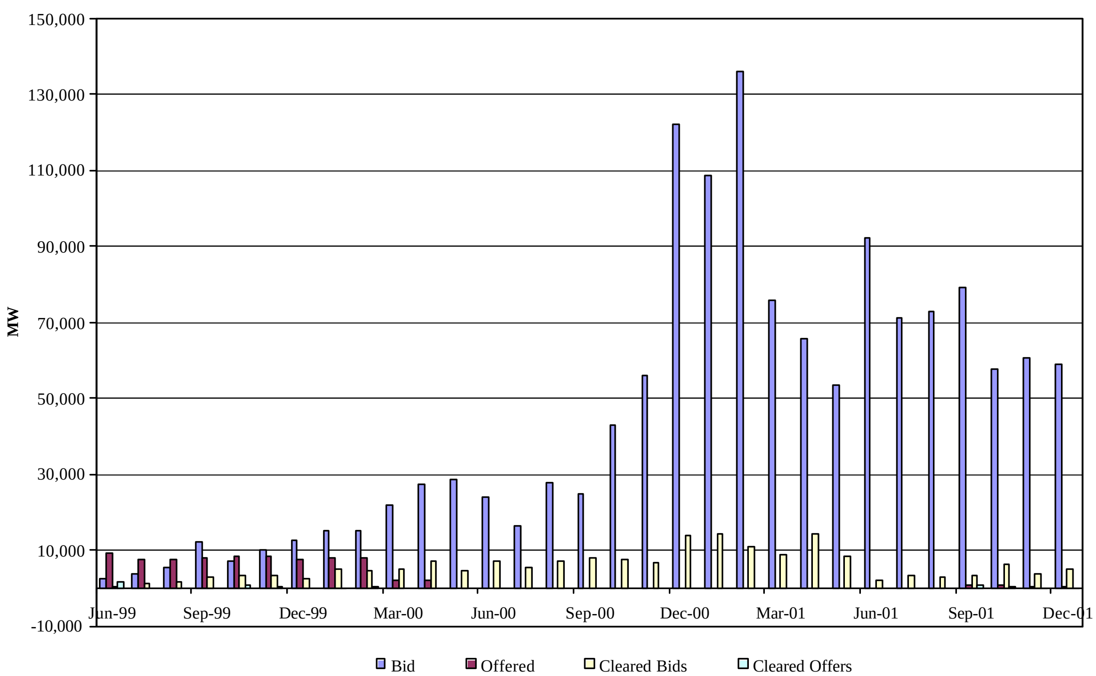


Figure 7, Percentage of Bid and Offer Volume Cleared, presents the percentage of bids and offers that cleared. Cleared bids decreased from 32% of total bids in 1999, to 24% in 2000 and 9% in 2001, while cleared offers were 4%, 2%, and 55% of total offers during 1999, 2000, and 2001, respectively. The lower percentage of cleared bids reflects the large increase in total bids, while the increase in the percent of cleared offers reflects the very low number of offers in 2001.

Figure 7
Percentage of Bid and Offer Volume Cleared

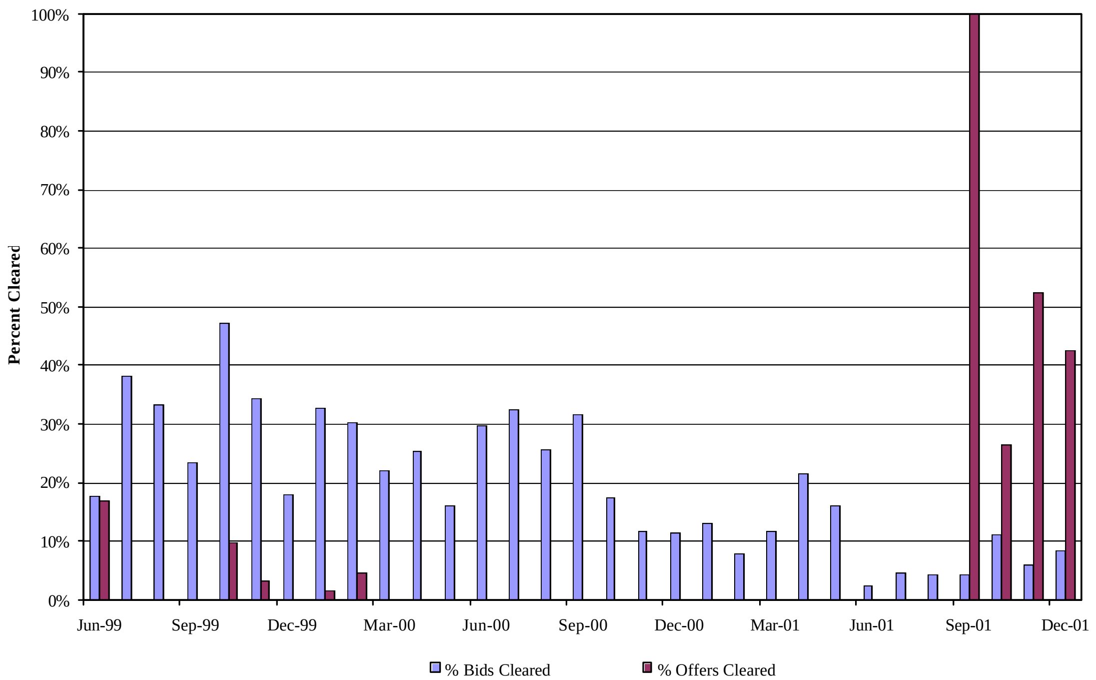


Figure 8, Ten Highest Revenue Producing FTR Sinks Purchased, depicts the revenue and MW volume of the ten FTR sinks purchased in the auction that produced the most revenue. Eight of these ten are located in Eastern PJM, and these ten accounted for 53% of all FTR bid revenue produced.

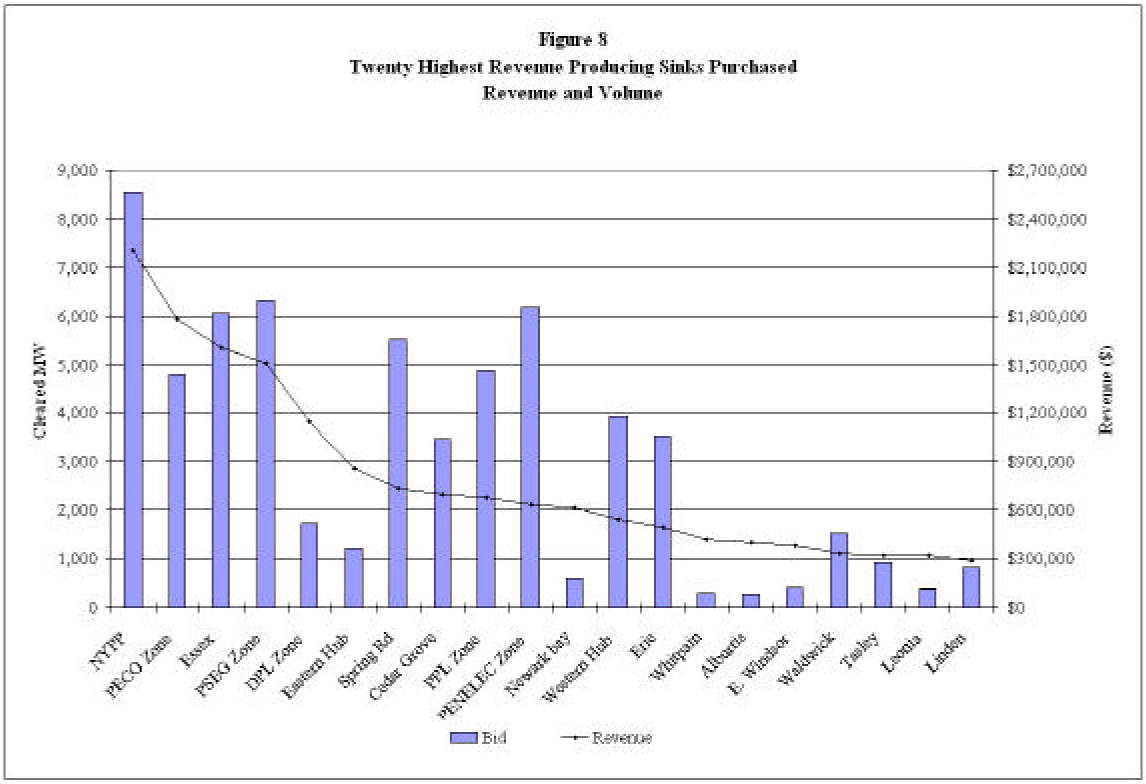


Figure 9, Ten Highest Revenue Producing FTR Sinks Sold, depicts the revenue and MW volume of the ten FTR sinks sold in the auction that produced the most revenue. These ten sinks accounted for 47% of all FTR offer revenue produced and their locations were dispersed throughout the system.

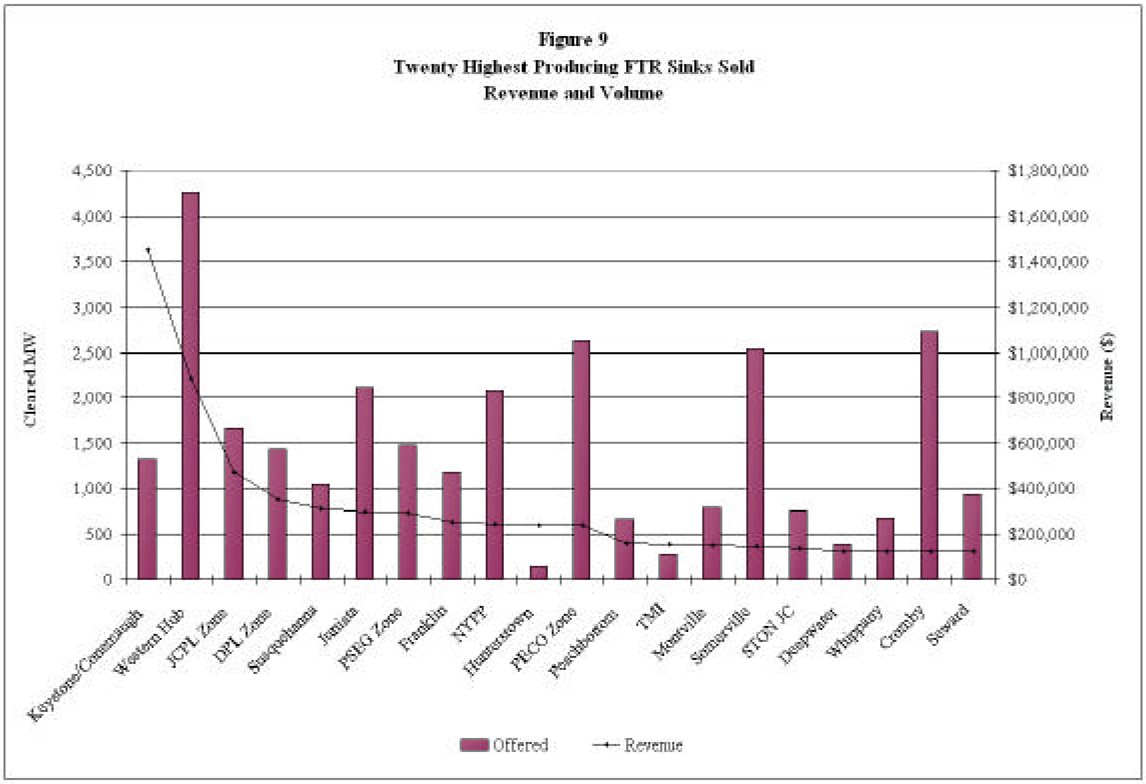


Figure 10, Ten Highest Revenue Producing FTR Sources Purchased, depicts the revenue and MW volume of the ten FTR sources that produced the most revenue. These ten sources accounted for 48% of all FTR bid revenue produced. Three of the top four are located in Western PJM and accounted for 24% of all FTR bid revenue produced, and five of the top ten were in Eastern PJM and accounted for 17% of all FTR bid revenue. The top three accounted for 27% of all FTR bid revenue produced.

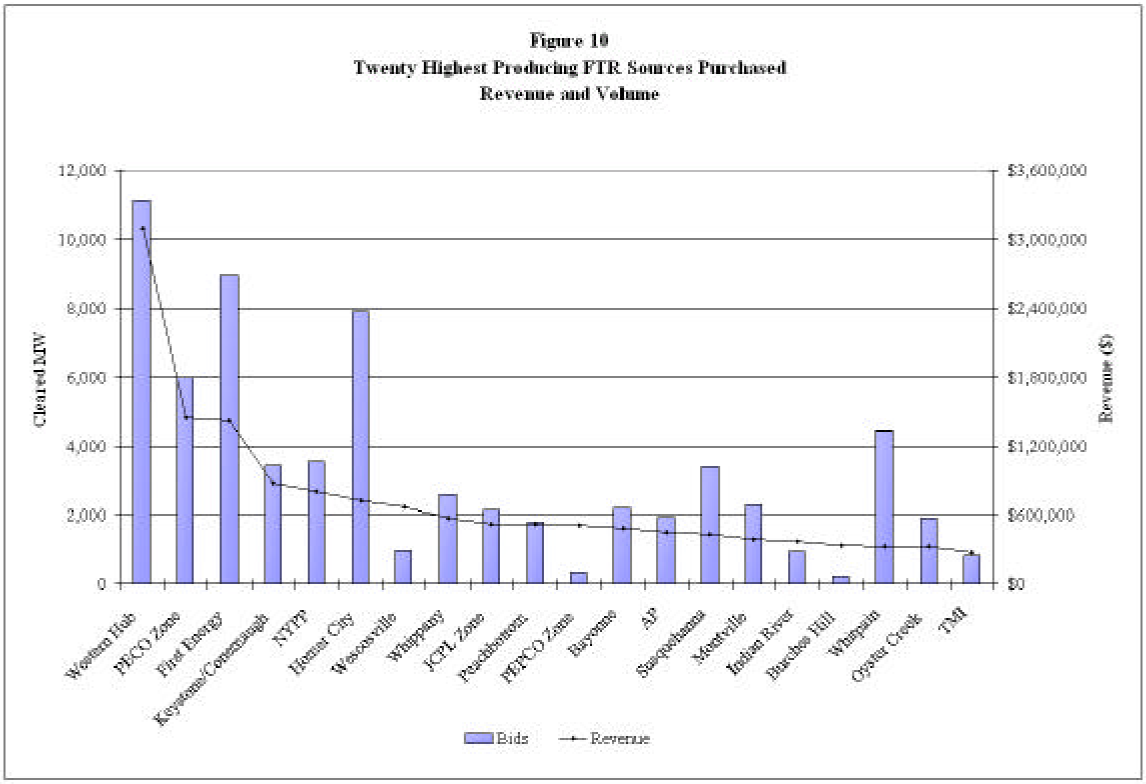


Figure 11, Ten Highest Revenue Producing FTR Sources Sold, presents the revenue and MW volume of the ten FTR sources sold that produced the most revenue. These ten accounted for 47% of all FTR offer revenue produced, and all except NYPP are located in Eastern PJM.

Figure 11
Twenty Highest Producing FTR Sources Sold
Revenue and Volume