REPORT
TO
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

CAPACITY MARKET QUESTIONS

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

November 2001

Summary

This report responds to the request of the Pennsylvania Public Utility Commission ("PaPUC") for a formal report on the PJM capacity credit markets ("ICAP market" or "capacity credit markets") covering the period from January through April, 2001 and is issued in accordance with the PJM Market Monitoring Plan, PJM Open Access Transmission Tariff, Attachment M. 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 is provided at this time in order 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). A copy of this report is being submitted to the FERC.

The MMU concluded, based on its analysis, that there was an exercise of undue market power, as defined below, in the PJM capacity credit markets during the first quarter of 2001. The exercise of such market power was by a single entity, acting unilaterally. The result of the exercise of market power was that the price in the capacity credit markets during this interval was higher than it would have been in a competitive market.

In response to the observed behavior, in January 2001 the MMU proposed a change to the market rules contained in the Reliability Assurance Agreement among Load Serving Entities in the PJM Control Area ("RAA"). The proposed change was to the methodology used to allocate capacity deficiency revenues. These deficiency revenues are collected, at the Capacity Deficiency Rate ("CDR"), from Load Serving Entities ("LSE") that fail to meet their capacity obligations under the RAA. During the period analyzed in this report, the methodology was to allocate 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 either withhold that capacity from the market or offer it for sale at a price equal to the CDR ($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 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 so as to yield the higher of market value or an allocation which included all LSEs that had met their obligations.

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.

More specifically, in its filings with the FERC, PJM explained the need to revise the methodology for distribution of capacity deficiency revenues. In its March 7, 2001 submission of the proposed change, PJM explained,

> The amendment filed herewith revises the methodology to correct a design flaw that has stifled robust competition in the PJM Capacity Credit market. PJM's Market Monitoring Unit has determined that under circumstances where an individual capacity owner has a longer position than the aggregate pool is long (that is, it owns capacity that Load Serving Entities must acquire to avoid deficiency charges), the current methodology permits such a capacity owner unilaterally effectively to set the market price for Capacity Credits at a level equal to the [CDR]. The CDR is the rate a Load Serving Entity must pay as a deficiency charge if it lacks sufficient capacity to meet its RAA capacity obligation. Moreover, but for the design flaw, the CDR is generally, though not always, higher than the competitive market clearing price.
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> The amendment, in some circumstances, will reduce the share of capacity deficiency revenues distributed to owners of excess capacity, but will generally ensure that the capacity owners receive at least the market value for excess capacity needed by the pool. In circumstances where the value of capacity in a competitive market is lower than the CDR and where a capacity owner has a longer position than the aggregate pool is long, this reduction will eliminate the flawed incentive, caused by the current design, for that owner to offer capacity at the CDR or higher.

March 7, 2001 submission, Docket No. ER-1-1440 (footnotes omitted) (copy attached hereto at Tab 1).

Several market participants and public agencies (including the PaPUC and the Pennsylvania Office of Consumer Advocate) intervened in the FERC proceeding in support of the amendment which PJM proposed.[1] PPL Electric Utilities Corporation and PPL EnergyPlus, LLC (jointly "PPL") intervened in opposition. A copy of PPL's filing

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[1] In addition to the PaPUC and the Pennsylvania Office of Consumer Advocate, the following entities intervened in support of the rule change: GPU Energy, NJ Division of the Ratepayer Advocate, Maryland Office of People's Counsel, Mid-Atlantic Power Supply Association, and The New Power Company. The following entities intervened but stated no position: Dynegy Power Marketing, Inc., and Enron Power Marketing, Inc.

with FERC, in opposition, dated March 21, 2001, is attached at Tab 2. PJM's April 5, 2001 response to PPL's filing (Tab 3) and PPL's April 17, 2001 response to that PJM filing (Tab 4) are also attached. On April 25, 2001, the PaPUC filed Supplemental Comments in support of the amendment. The PJM filings describe the reasons for and benefits of the amendment. The additional filings are provided to assist the PaPUC's understanding of arguments made against the proposed amendment.

Responses to Questions of the PaPUC

The PaPUC asked that the MMU respond to six specific questions. The questions and responses are below.

1. **Whether any market participant has failed or refused to comply with the rules, standards, procedures, and practices of the PJM ICAP Market as set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Manuals, and/or the PJM Regional Practices Document. Please identify the market participant(s) who have failed or refused compliance with such rules, standard procedures and practices, the details of such failure or refusal, and remedies sought or applied (if any) by PJM.**

No market participants have failed or refused to comply with the rules, standards, procedures, and practices of the PJM ICAP market. The rules did not explicitly prohibit the actions identified in this report. This fact underscores the necessity of amending the RAA in order to eliminate the incentive to engage in the identified conduct.

2. **Whether there are actual or potential design flaws in the PJM ICAP market operating rules, standards, procedures, and practices as set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Manuals, and the PJM Regional Practices Document. If actual or potential design flaws do exist, please provide a detailed description of such flaws.**

PJM and the MMU have addressed these issues in several recent reports and filings. Please see the PJM Interconnection State of the Market Report 2000. Please also see PJM's filings regarding the capacity markets:

a. to address the allocation of capacity deficiency revenues, FERC Docket No. ER01-1440-000 (Tabs 1, 3 and 4);
b. to address reliance upon a daily capacity market and to propose the introduction of an interval capacity market, FERC Docket No. EL01-63-003 (Tab 5); and
c. to respond to New Power's complaint regarding market power in the PJM capacity markets, FERC Docket No. EL01-105-000 (Tab 6).

PJM has not identified other specific design flaws in the PJM ICAP market. The MMU continues to monitor the capacity credit market for design flaws, compliance with existing rules and for the potential of any market participant to exercise undue market power.

As a general matter, conditions in the capacity credit market make the potential exercise of market power a continuing concern. Demand is extremely inelastic since it is a function of 12-month historical loads and PJM's capacity requirement rules. Frequently, only a few generators have excess capacity and are therefore in a position to sell capacity. Thus, despite an installed capacity HHI consistent with "moderate concentration," capacity owners can be in a position to exercise market power. Even with more generators offering capacity into the market, economic theory suggests that significant market power may exist in the presence of the low demand elasticity that characterizes the capacity markets.[2]

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. For example, PJM proposed changes in the underlying structure of the capacity obligation, including revision of the daily capacity commitment to a seasonal commitment. The FERC accepted these changes effective July 1, 2001. PJM Interconnection, L.L.C., 95 FERC ¶ 61,330 (2001).

3. Whether there exist structural problems in the PJM ICAP market which may inhibit a robust and competitive market and your proposed remedies for such structural problems.

Please see the response to question 2.

4. Whether there has been actual or attempted exercise of undue market power by any market participant or participants or there exists a potential for the exercise of such undue market power, and the identity of such market participants exercising or attempting to exercise undue market power.

Please see the response to question 5.

5. Detailed information for the PJM ICAP market for each day for the period from October 1, 2000 to the present, including but not limited to:

- **a. Available capacity and total daily obligation for PJM as a whole, and daily obligation for each load serving entity;**
- **b. Day ahead and daily capacity position of each load serving entity;**
- **c. Capacity Deficiency Rate penalties incurred, including any escalator penalty;**
- **d. Cumulative number of deficient days for each load serving entity;**
- **e. Total capacity deficiency rate revenues collected and allocated by recipient;**
- f. **Offer and purchase bids into the day ahead and other ICAP auction markets, by Load Serving Entities.**

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 without manipulation or the exercise of market power. The exercise of undue market power is thus an action

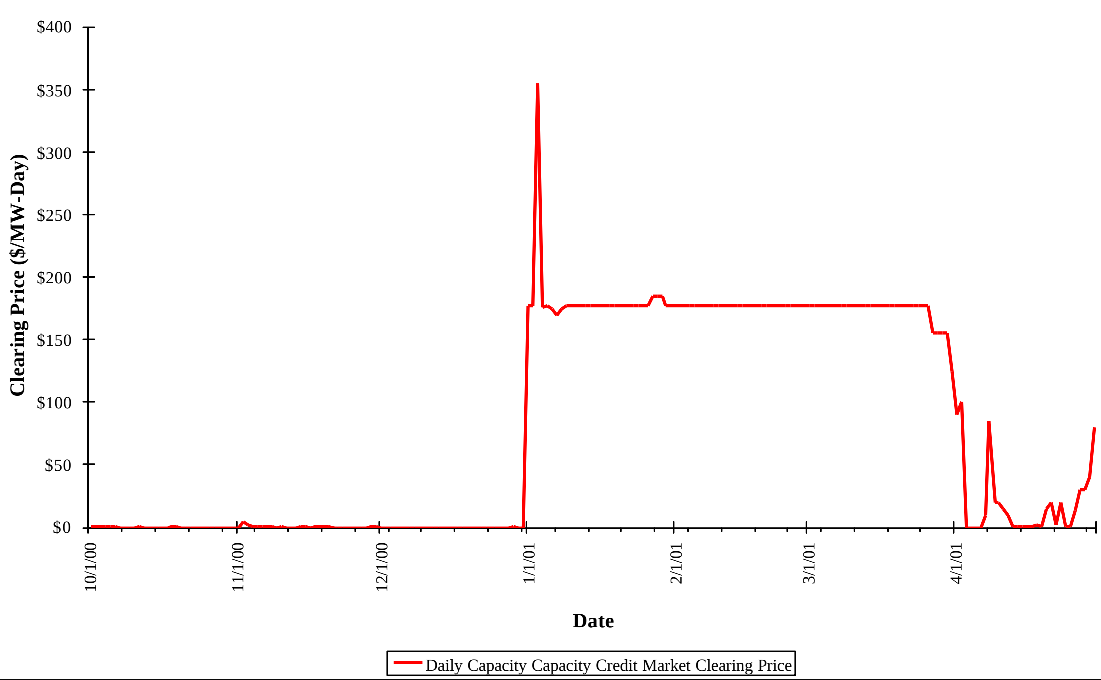
2 See PJM Interconnection State of the Market Report 2000.

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.

It is clear that during the first quarter of 2001, a participant in the PJM daily capacity market did successfully raise 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. The rules of the capacity market stated in the RAA did not explicitly prohibit this conduct. Nonetheless, the behavior constituted the exercise of undue market power and was inconsistent with the intended consequences of the rules. The prices in the daily capacity credit market during portions of the first quarter of 2001 were higher as the direct result of actions by a participant in the PJM capacity 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 1 shows the prices in the PJM daily capacity 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.

Figure 1: Daily Capacity Credit Market Clearing Price



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

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.

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.

When there is adequate capacity, the competitive price in the daily capacity credit market is a function of the short run cost of capacity and the other opportunities available to the owners of capacity resources. An owner of a generating unit within PJM has the ability to sell into the PJM capacity market or to sell firm energy out of PJM. The opportunity to sell firm energy outside PJM is dependent on adequate transmission service within PJM and into the contiguous control area.[3] The value of the opportunity to sell firm energy outside PJM is a function of a number of factors including the expected external price for firm energy, both daily and longer term, the expected internal PJM price for energy, the probability of an unanticipated price spike in the external and internal markets, the probability of recall and the cost of transmission. The value of the opportunity also depends on the availability of transmission service. If transmission is not available, the external energy price is irrelevant. For a daily capacity market, a conservative approximation of the competitive price can be calculated by multiplying the differential between the external forward energy price and the internal forward energy price by the 16 on peak hours, as that is a conservative estimate of the value of the opportunity foregone by selling capacity in the PJM capacity market.[4]

In the last quarter of 2000, the net PJM capacity position was approximately 2,000 MW long. Thus, the available supply of capacity exceeded the obligation to purchase capacity. (Figure 2.) 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.

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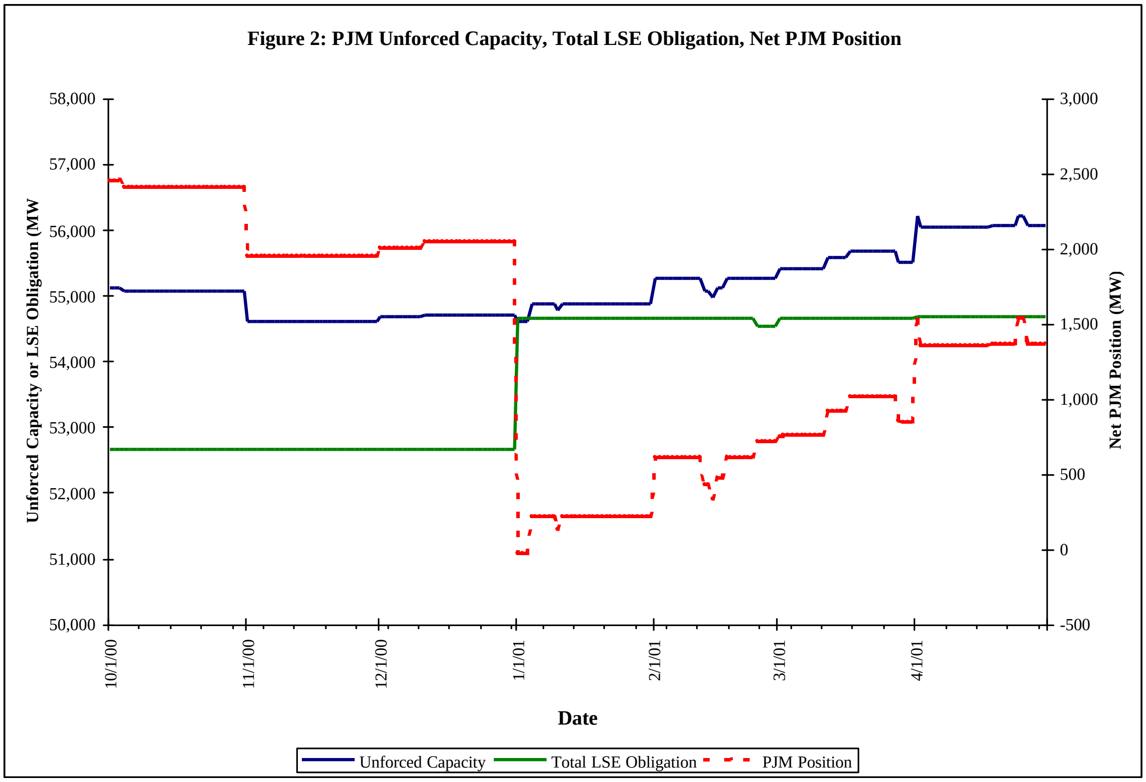
[3] Transmission service within PJM needs to be firm in the sense that there is a low probability of being interrupted and not necessarily firm in the tariff sense. There is no requirement that exporters of capacity have firm transmission service within PJM.

[4] The 16 on peak hours are used because the forward price contracts in the energy price comparison are priced over 16 hours.

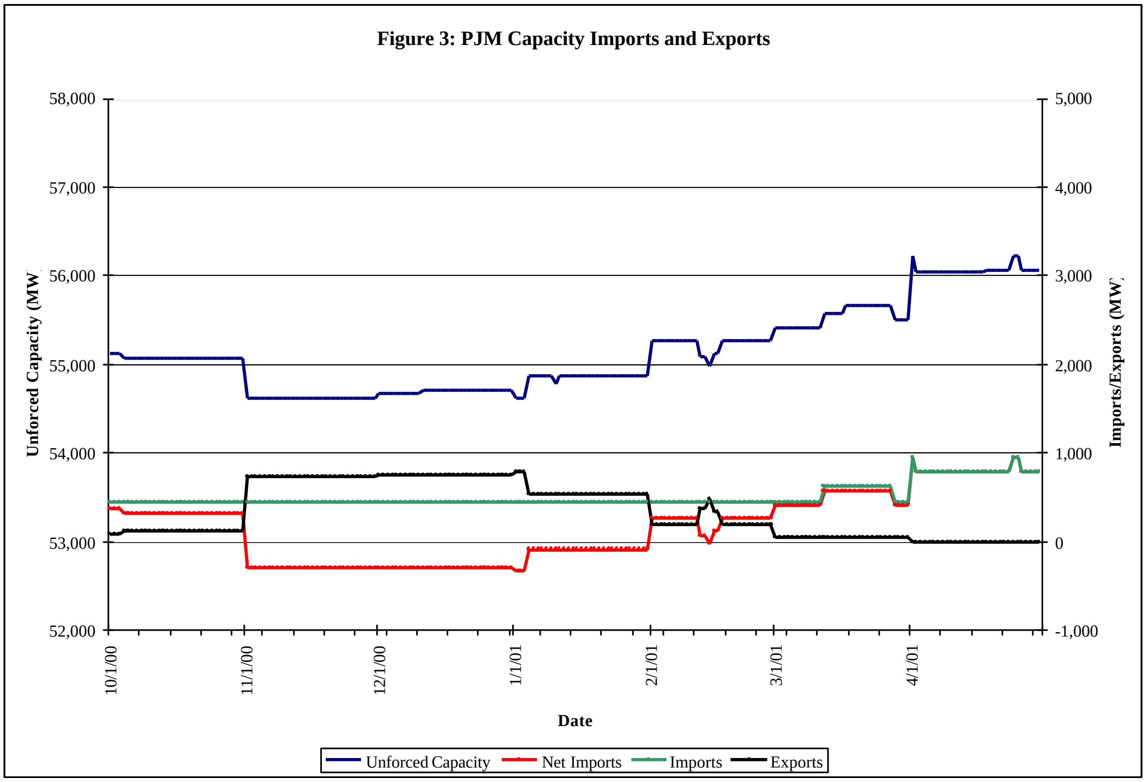


The reasons for the changed balance between supply and demand are straightforward. On the demand side, the capacity obligations of LSEs grew by nearly 2,000 MW or almost 4 percent on January 1. This increase was the result of the process by which capacity obligations are determined under the RAA. Capacity obligations are primarily a function of the weather adjusted peak load for the prior summer and become effective on January 1 of each year.[5]

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 3.) 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 2) 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.

[5] 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 market price is compared to the alternative opportunities available for selling capacity, or its equivalent, firm energy, it becomes clear that, based on the available data for the identified alternatives, the price in the PJM daily capacity 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 4 shows the prices in the PJM daily capacity 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 4, 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.

For the period 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 on a firm basis, subject to the risk of recall, which is 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.

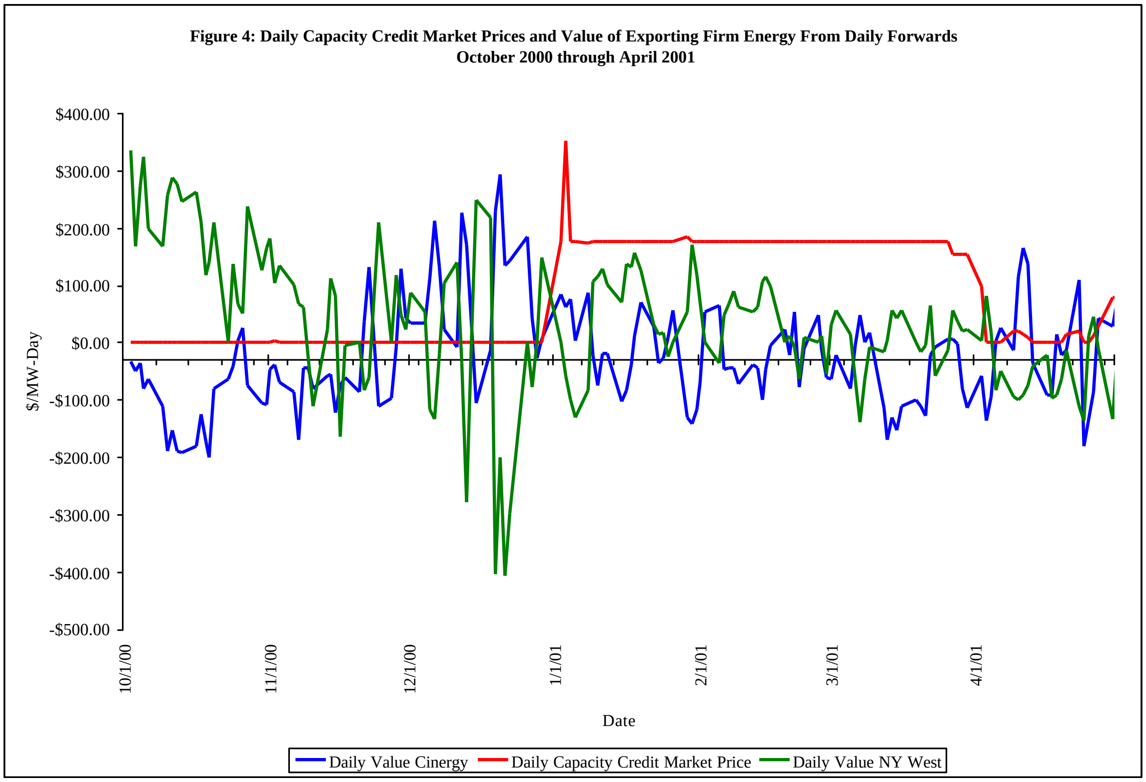
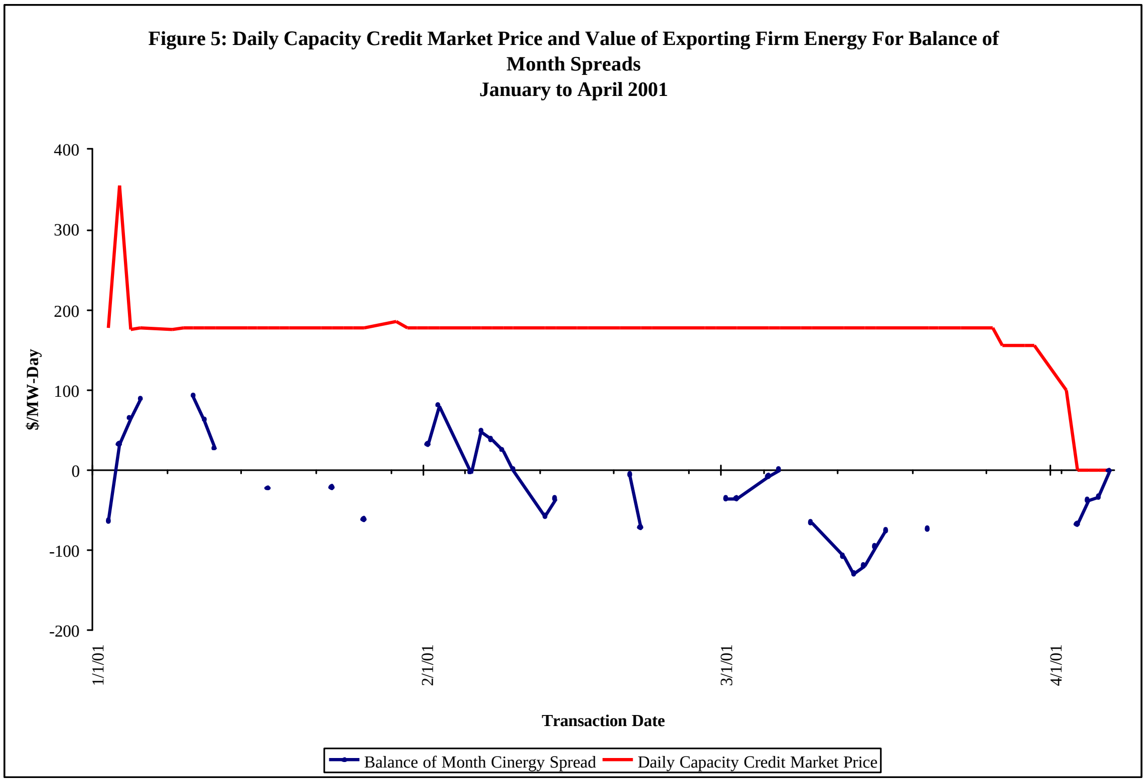


Figure 5 shows a similar comparison for balance of the month forward prices at Cinergy. Again, for the period from January to April, the price in the daily PJM capacity credit market exceeded the spread between the PJM West hub and Cinergy, valued over 16 hours. In other words, the price of capacity 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.[6]

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

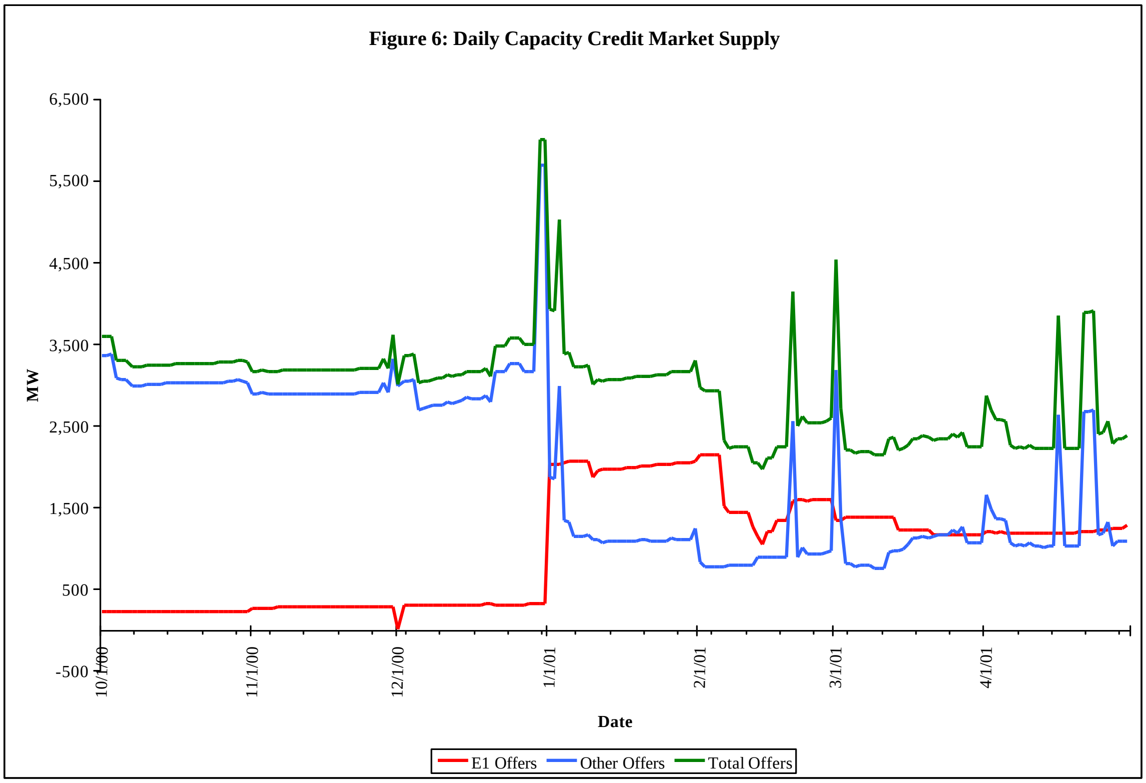


The ability of a seller to unilaterally exercise market power in the daily market is a function of the seller's available capacity compared to daily demand and the available capacity of other sellers. If the seller's available capacity exceeds the difference between the daily demand for capacity and 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.

The way in which Entity1 exercised market power in the daily capacity markets is clear. Entity1 offered more total available capacity in the daily market than the total net capacity offers in the total PJM daily market. In other words, Entity1 was longer than the total market. Entity1's offers of capacity were greater than the daily demand for capacity less the capacity offered by all other suppliers.[7] In order to cover their obligations, LSEs had to buy capacity from E1. Entity1 held this market position, in which E1 offered more capacity than the total net excess capacity offers in PJM, for the period from January 1 to March 30, 2001.

[7] 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.

Entity1 substantially increased its offers of capacity in the daily market as of January 1, 2001 as shown in Figure 6. Figure 7 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, although the difference narrowed from late February through late

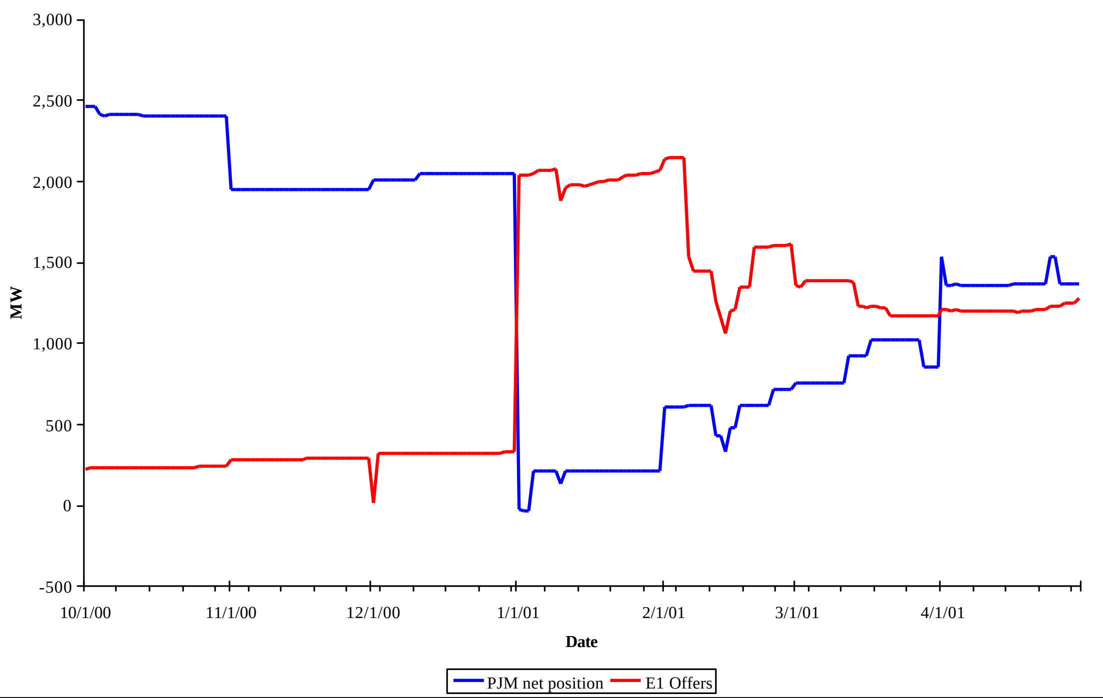


March. Entity1 offers comprised more than half the total offers for the January to March period while the balance of the capacity offers were made by a number of other suppliers.

Figure 8 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.

Figures 6, 7 and 8 show that as a result of the fact that 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 did not buy from E1, there were no other alternative sellers available and the LSEs would have become deficient and paid the capacity deficiency rate of $177.30/MW-day as a result. Entity1's share of total capacity offers put E1 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 rather than purchasing capacity at a price greater than $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.[8]

Figure 7: Daily Capacity Credit Market Supply and Demand



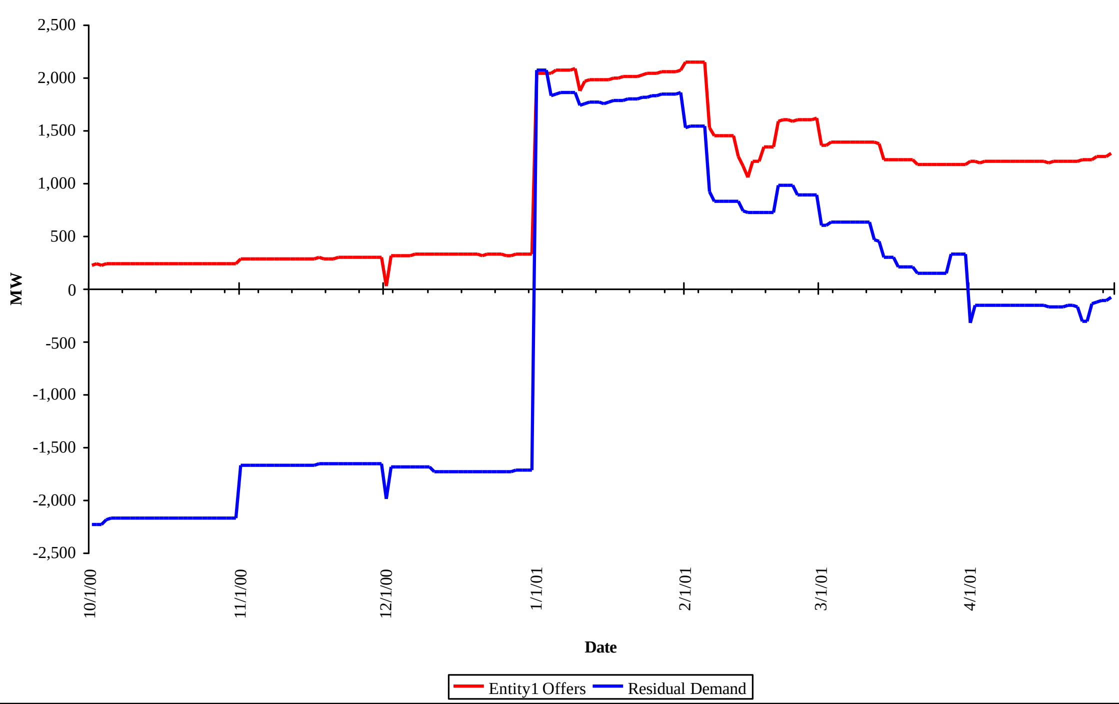
As long as the overall market was extremely tight, in the sense that total supply was very close to total demand, the deficiency revenues accruing to E1 would not be affected if other suppliers priced below $177.30 or if other suppliers decided to follow the same strategy as E1. If other suppliers sold 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 ability to unilaterally 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,

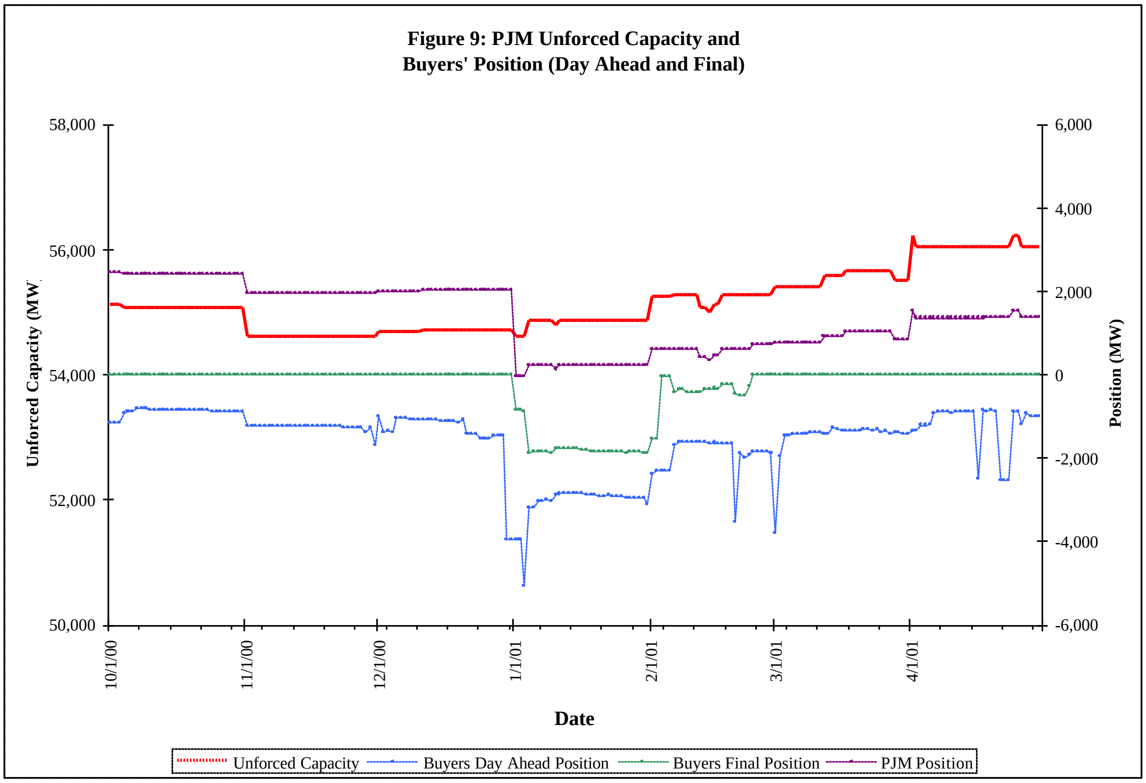
8 In fact, E1 was in a better position if they offered capacity at a price in excess of $177.30 because the RAA rules in effect at the time penalized LSEs who were deficient for more than 30 days by increasing the capacity deficiency rate that they must pay. Thus by forcing LSEs deficient, E1 would ultimately increase the capacity deficiency revenues available.

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 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 8: Entity1 Supply and Residual Demand

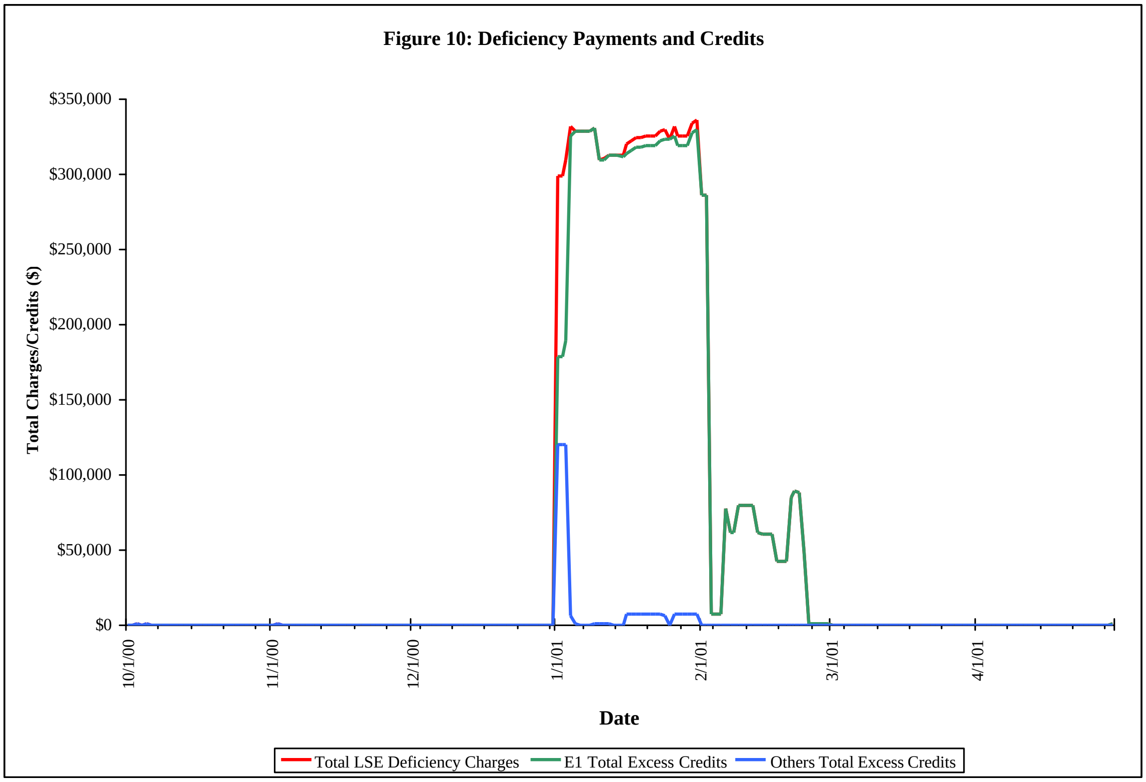


Buyers of capacity relied on the daily market more heavily in January and February 2001 than in late 2000, as shown in Figure 9. The Buyers' Day Ahead Position line in Figure 9 shows the extent to which LSEs needed to purchase in the daily market in order to avoid being deficient. From October 1 to December 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 a price less than $177.30/MW-day in the daily market in the period from October 1 to December 31, 2000 that was not the case during January and February 2001. In the January to February period, short capacity purchasers were not able to purchase their full capacity requirements in the daily capacity 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 9). Capacity purchasers were not deficient in March and April. Figure 9 also shows the extent to which capacity purchasers met their obligations in the daily capacity 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 as the buyers' aggregate net position is zero after February 24.



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 amount of capacity deficiency charges paid and collected 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.

Entity1 captured virtually 100% of the revenues resulting from capacity deficiency charges during the period from January through February, as shown in Figure 10.



Prices through March 2001 stayed near the CDR of $177.30/MW-Day (Figure 1). However, as E1's market position weakened somewhat (Figure 8), 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 2). Some capacity purchasers bought capacity bilaterally and reduced 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 8). 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.

6. **Please state whether the Market Monitoring Unit lacks adequate authority or resources to investigate or remedy any problems it has identified in the PJM Installed Capacity Market. If so, what additional authority or resources would be necessary?**

The MMU continuously evaluates the need for additional enforcement authority. While at this time the MMU has adequate authority and resources to investigate and report on problems in the capacity credit markets, the MMU is evaluating the need for additional authority to address ongoing issues in the capacity markets. Regarding the issues identified in this report, the MMU identified the problem and proposed a solution to PJM, to the appropriate PJM member committees and ultimately to the FERC. Pursuant to its Operating Agreement, the RAA, and FERC guidance, PJM relies on its stakeholder process to develop solutions which reflect the input and perspectives of various participants and market sectors and on which there is frequently consensus among market participants. Through this process, PJM is generally able to present solutions to the FERC that engender little or no dispute. In this case, the stakeholder process yielded near unanimous agreement that the amendment to the RAA was an appropriate response and solution. On the other hand, the process was time-consuming.

Conclusion

The MMU concludes 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. The exercise of market power took the form of economic withholding. Entity1 was able to successfully withhold capacity by offering the capacity at prices greater than the CDR because Entity1 held capacity that LSEs needed to purchase in order to meet their capacity obligations. Entity1 held more net capacity than the total excess capacity in the market.

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, prices have declined in the daily, monthly and multi-monthly markets. (See Figure 11.) The capacity credit market continues to be the focus of significant attention by PJM and its members.

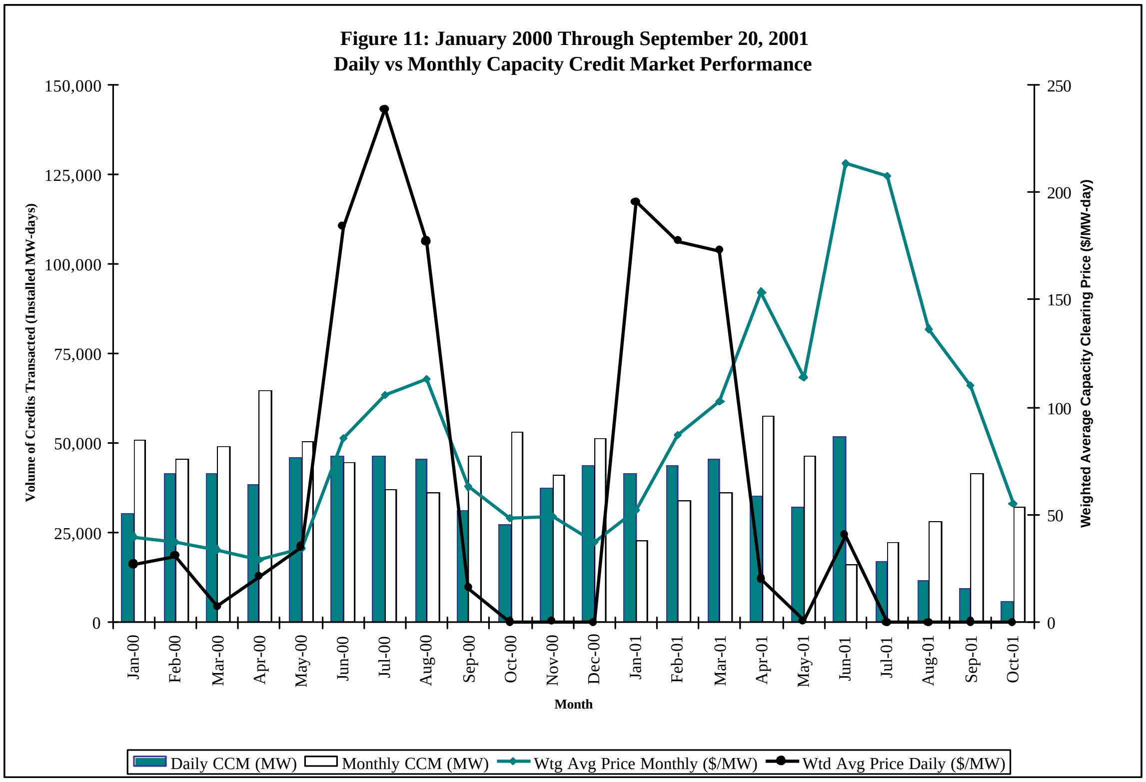


Figure 11: January 2000 Through September 20, 2001
Daily vs Monthly Capacity Credit Market Performance
Volume of Credits Transacted (Installed MW-days)
Weighted Average Capacity Clearing Price ($/MW-day)
150,000
125,000
100,000
75,000
50,000
25,000
0
250
200
150
100
50
0
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Jun-01
Jul-01
Aug-01
Sep-01
Oct-01
Month
Daily CCM (MW)
Monthly CCM (MW)
Wtg Avg Price Monthly ($/MW)
Wtd Avg Price Daily ($/MW)