SECTION 3—INTERCHANGE TRANSACTIONS

PJM has interfaces with five contiguous, external regions. These interfaces are the seams between PJM and other regions. PJM market participants import energy from and export energy to external regions on a continuous basis.[1] These transactions may serve to fulfill long-term or short-term bilateral contracts or to take advantage of price differentials. Prior to the addition of the PJM-West Region on April 1, 2002, the PJM interfaces were PJM/New York ISO (PJM/NYIS), PJM/Allegheny Power System (PJM/APS), PJM/FirstEnergy (PJM/FE) and PJM/Dominion Virginia Power (PJM/VAP). With the addition of the PJM-West Region, the PJM/APS interface was internalized and two new external interfaces were added, PJM/American Electric Power (PJM/AEP) and PJM/Duquesne Light Company (PJM/DLCO).[2] About 410,000 MWh per month of imports at the PJM/APS interface were internalized as a result of market growth to incorporate the PJM-West Region.

OVERVIEW

- **Loop Flow.** Loop flow results when the transmission contract path for energy transactions does not match the actual path of energy flows on the transmission system. Loop flows can arise from transactions that are scheduled into, out of, or around the PJM system. Outside of PJM's LMP-based energy market, energy is scheduled and paid for based on contract path while the actual associated energy deliveries flow on the path of least resistance. Loop flows can result when a transaction is scheduled between two external control areas and some or all of the actual flows occur at PJM interfaces. Loop flows can also result when transactions are scheduled into or out of PJM on one interface and actually flow on another. Although total PJM scheduled and actual flows were approximately equal in 2002, such was not the case for each individual interface.

- **Interface Pricing Issue.** PJM experienced a significant loop flow issue during the summer of 2002 when transactions scheduled at the PJM/VAP interface actually flowed at the PJM/AEP interface. The issue resulted from actions designed to exploit differences between the way in which PJM locational marginal prices (LMPs) are determined and the artificial contract paths existing in the areas to the west and south of PJM. In particular, there was a large and growing discrepancy between contract and actual power flows at the PJM/AEP interface and at the PJM/VAP interface. To address this issue, on July 19, 2002, the PJM Market Monitoring Unit (MMU) notified market participants of a rule change governing interface pricing for transactions, scheduled at the PJM/VAP interface, but delivered at the PJM/AEP interface, if they include an ECAR, MAIN, MAPP, or SPP control area, or the AECI control area as the source.[3] Since then, such transactions have been priced at the PJM/AEP interface price regardless of contract path.[4]

- **Aggregate Imports and Exports.** For each month of 2002, PJM was a net importer. Exports have increased since the addition of the PJM-West Region.

1 These transactions occur primarily in the real-time market. Approximately 85 percent of total gross imports and 93 percent of gross exports take place in the real-time market without corresponding day-ahead transactions.

2 Interfaces are named after the adjacent control areas. This naming convention does not imply anything about the companies that operate the adjacent control areas.

3 The four North American Electric Reliability (NERC) Regional Councils involved are the East Central Area Reliability Coordination Agreement (ECAR), the Mid-American Interconnected Network, Inc. (MAIN), the Mid-Continent Area Power Pool (MAPP) and the Southwest Power Pool, Inc. (SPP). The other control area is that of the Associated Electric Cooperative, Inc (AECI) based in Springfield, Missouri.

4 The language is from the current rule which was updated most recently on January 9, 2003.

- **Interface Imports and Exports.** For 2002, the PJM/FE interface accounted for approximately 53 percent of net imports. The PJM/NYIS interface accounted for approximately 98 percent of net exports.

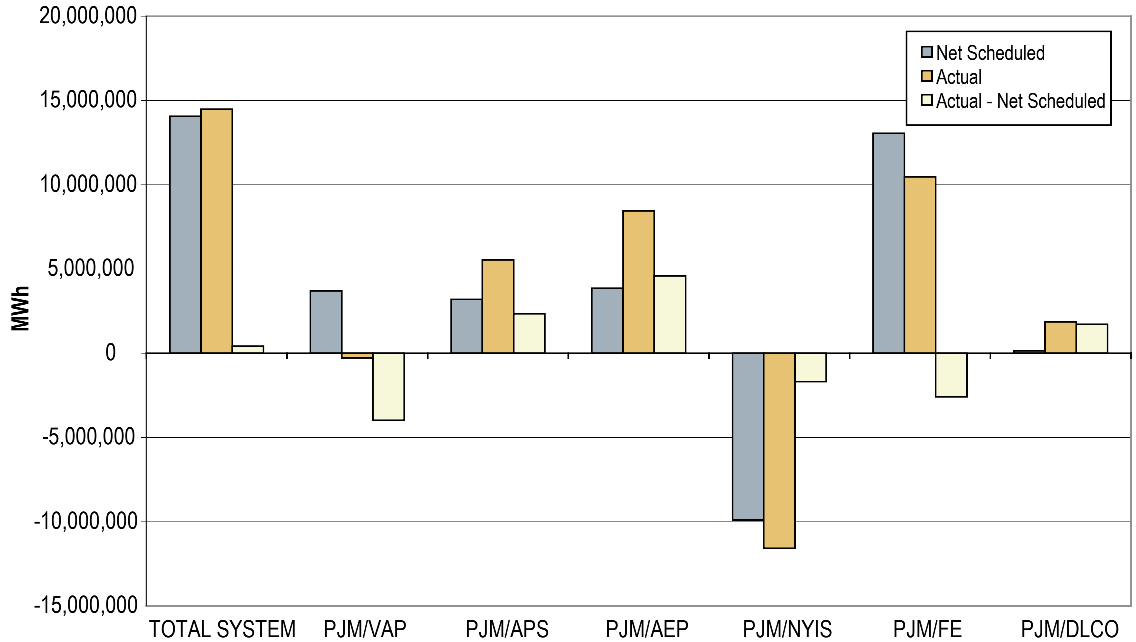
LOOP FLOW

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

Although total PJM net scheduled and actual flows were approximately equal in 2002, such was not the case for each individual interface (Figure 3-1).

For PJM as a whole, net scheduled and actual interface flows were approximately balanced in 2002. Actual total system net imports were approximately 14.5 million MWh, exceeding the scheduled total of approximately 14.1 million MWh by 0.4 million MWh or less than three percent. Flow balance varied, however, at each individual interface. The PJM/VAP and the PJM/AEP interfaces were most out of balance on an annual basis. At the PJM/VAP interface, net scheduled imports exceeded net actual imports, on average, by approximately 4.0 million MWh, an average of 332,000 MWh per month. At the PJM/AEP interface, net actual imports exceeded net scheduled imports by approximately 4.6 million MWh, an average of 511,000 MWh per month from April to December. At the PJM/NYIS interface net actual exports exceeded net scheduled by approximately 1.7 million MWh or 140,000 MWh per month; PJM/FE net scheduled imports exceeded actual by 2.6 million MWh or 215,000 MWh per month; PJM/DLCO net actual imports exceeded net scheduled by 1.7 million MWh or 191,000 MWh per month from April to December; PJM/APS net scheduled imports exceeded actual by 2.3 million MWh or 782,000 MWh per month.

Figure 3-1 Net Scheduled and Actual PJM Interface Flows: 2002



Interface Pricing Issues

On July 19, 2002, at approximately 1400 hours, the PJM MMU notified market participants that pricing for transactions scheduled at the PJM/VAP interface, but delivered at the PJM/AEP interface, would be corrected effective at 1500 hours. In particular, PJM notified participants that, until further notice, if a transaction scheduled into PJM at the PJM/VAP interface includes an ECAR or MAIN control area as determined by NERC Tag, then that transaction would be priced at the PJM/AEP interface price regardless of contract path. PJM took this action based on a large and growing discrepancy between contract and actual power flows at the PJM/AEP and the PJM/VAP interfaces.

This PJM action was taken in full accord with 3.3.1(d) of Schedule 1 of the "Operating Agreement," governing payment for deliveries to the PJM spot market. It states in relevant part: "For pool External Resources the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding interface point between adjacent control areas and the area comprised of the PJM-West Region and PJM Control Area."

Historically, PJM had implemented section 3.3.1(d) by paying all import transactions scheduled from the adjacent control area the LMP at the interface assigned to that adjacent control area. The calculation of LMP for each interface was based on an assumption about the source of flows within each adjacent control area. The source of flows was known as the reference bus and served as the basis for detailed modeling of electrical flows from the adjacent control area to PJM. The detailed modeling reflected the underlying electric reality of the transmission system and, therefore, the fact that flows from each control area have identifiable impacts on each interface. The LMP at each interface bus was thus based on the expected flows over all interface buses that would result from imports delivered from the reference bus in the adjacent system. For example, flows from the reference bus in the AEP control area on July 19, 2002, had a modeled impact of 60 percent on the PJM/AEP interface, 20 percent on the PJM/FE interface, and 12 percent on the PJM/VAP interface. As a result, when the contract and actual power flow paths were consistent, the LMP paid to transactions at the PJM/AEP interface bus explicitly accounted for the fact that portions of the transaction had flowed at other buses.

Historically, PJM had paid external transactions assuming that these transactions, scheduled from or through the adjacent control area, were actually delivered, consistent with the schedule, directly from the control area to the interface between PJM and that control area. Therefore, PJM paid external transactions based on scheduled flows to the interfaces. PJM's interface LMPs did not assume that the transactions were scheduled based on the purchase of contract path transmission service that was inconsistent with the actual transaction flow. When PJM observed significant and growing differentials between scheduled and actual flows, PJM issued its pricing notice. The pricing notice provides that import transactions scheduled into PJM at the PJM/VAP interface are paid the price at the PJM/AEP interface when those transactions originate to the west of PJM, regardless of artificial contract paths constructed to avoid the required pricing based on the appropriate flow analysis under section 3.3.1(d). PJM did not take similar action with respect to import transactions scheduled into the other PJM interfaces, including PJM/FE, PJM/DLCO and PJM/NYIS, because PJM's flow analysis had not indicated any similar gaming behavior attempting to avoid the required flow-based pricing at these interfaces.

Parties entered into transactions with scheduled contract paths different from actual flows in response to the fact that the LMP at the PJM/VAP interface was higher than the LMP at the PJM/AEP interface, and in response to the observed fact that PJM had assumed that contract paths were consistent with actual flows and, as a result, paid transactions the LMP based on their scheduled contract path. The difference in interface LMPs, when it existed, reflected transmission constraints within PJM and the fact that increased power flows at the PJM/VAP interface were more valuable because they were on the congested side of the constraints.

The difference between contract and actual path power flows from the west (primarily the ECAR and MAIN control areas) created a problem because the power scheduled into the PJM/VAP interface actually flowed at the PJM/AEP interface and exacerbated internal PJM congestion. The more power from generating sources to the west was scheduled (contract path) into the PJM/VAP interface, the farther apart the LMPs at the two PJM interfaces were forced by the actual power flows. Despite the fact that the LMP at the PJM/AEP interface indicated that increased power flows had a low or, at times, a negative value, actual power flows increased at the PJM/AEP interface. This occurred because transactions were paid the PJM/VAP interface LMP (based on their scheduled, i.e. contracted, flows) which was, in turn, based on PJM's assumption that participants were scheduling on direct paths from adjacent control areas. In addition, the price signal to generation in the western part of PJM was inappropriately reduced as a result of scheduled transactions at the PJM/VAP interface actually flowing at the PJM/AEP interface.

In sum, pricing transactions based on scheduled rather than actual flows at these two interfaces resulted in perverse price signals, which in turn resulted in an unstable economic situation. The price signals incented behavior that made the problem worse rather than better. When the price signals to sellers are aligned with their actual delivered power flows, as LMP requires, rather than scheduled power flows, price arbitrage tends to drive disparate prices closer together. In the situation PJM found during 2002, the false arbitrage drove the prices farther apart because the price signals to the sellers were not aligned with the actual power that they delivered.

The differences between actual and scheduled power flows resulted from participant actions that fall into two broad categories: those that had long-term contractual arrangements; and those that took shorter term actions to take advantage of the observed price differential between the PJM/AEP and the PJM/VAP interfaces. For example, some participants purchased or generated energy in ECAR or MAIN and contracted for transmission service through Dominion Virginia Power (notwithstanding the actual flow through the PJM/AEP interface) solely to take advantage of the LMP differential between the PJM/AEP interface and the PJM/VAP interface.

The result of the PJM pricing notice was to decrease the incentive to engage in such a transaction because the participant would be paid the PJM/AEP interface price for the transaction based on the actual power flow.

As another example, a participant purchased energy from the PJM spot market at the PJM/AEP interface and delivered the energy to AEP. The participant purchased energy in AEP, purchased transmission service through Virginia and scheduled delivery to the PJM spot market at the PJM/VAP interface. On paper, the participant purchased power at the PJM/AEP interface, sold it at the PJM/VAP interface and then moved it back to the PJM/AEP interface. The participant was paid the difference in prices between the two interface buses even though absolutely nothing changed in PJM. The identical generation ran in PJM and these transactions resulted in absolutely no change in actual power flows.

The PJM pricing notice also removed the incentive to engage in this type of transaction because the participant would be paid the PJM/AEP interface price for both the purchase and sale, with a zero net result, as is appropriate for a transaction that has no impact on PJM power flows.

The described behaviors were clearly designed to exploit differences between the way in which PJM LMPs are determined (based on actual power flows) and the artificial contract paths existing in areas to the west and south of PJM.

As shown in Table 3-1 and Figure 3-2, the discrepancy between contract and actual power flows at the PJM/AEP and PJM/VAP interfaces increased beginning in June 2002. For example, the difference between actual and contract power flows at the PJM/AEP interface increased from an on-peak average of 904 MW in April and 1,042 MW in May, to 1,561 MW in June and 1,821 MW in the first 19 days of July. Correspondingly, the difference in price between the PJM/VAP and PJM/AEP interfaces increased from an on-peak average of $7.19 per MWh in April and $6.49 in May, to $14.33 in June and $16.44 in the first 19 days of July.

After peaking at 1,821 MW for the period from July 1 to 19, the average PJM/AEP on-peak power flow versus scheduled path differential decreased to 359 MW in August, 479 MW in September, 673 MW in October, 606 MW in November and 715 MW in December. The average on-peak LMP differential between the two interfaces was $16.44 from July 1 through July 19 and subsequently declined to $10.12 for August, $4.86 for September, $7.36 for October, $5.57 for November and $11.70 for December.

Figure 3-2 shows actual versus scheduled power flows for the two interfaces from April through December on an hourly basis. Figure 3-2 illustrates the increase in frequency of power flow differentials above 2,000 MW starting in mid-June and the consistently higher power flow differentials beginning in late June. Figure 3-2 also shows the associated interface LMP differentials on an hourly basis. Figure 3-2 illustrates increased density of interface LMP differentials above $30 beginning in mid-June and greater differentials beginning in late June.

Figure 3-3 shows the actual versus scheduled power flows and the LMP differential for the two interfaces in July. While several days in July had maximum power flow differences of 3,000 MW, July 17, 18 and 19 showed maximum differences of 2,714, 2,909 and 3,243 MW, respectively. The corresponding maximum LMP differentials were $30.26, $45.82 and $79.38. On July 19, there was a steadily increasing power flow differential and fluctuating LMP differentials between the two interface buses through the hour ended 1400, when PJM posted its modified interface pricing notice.

Table 3-1 shows the impact of PJM's interface pricing notice. While the average on-peak power flow versus scheduled path differential at the PJM/AEP interface was 1,821 MW from July 1 through July 19, the average for the balance of the month was 780 MW. The average on-peak LMP differential between the two interfaces was $16.44 from July 1 through July 19, while the average for the balance of the month was $9.88. Figures 3-2 and 3-3 illustrate the impact of PJM's interface pricing notice in more detail. There was a clear break in the level of the actual versus scheduled power flows after July 19. After July, the level of actual versus scheduled flows decreased as did the VAP-AEP price differentials.

As Figures 3-2 and 3-3 show, significant differentials between actual and scheduled power flows did not appear for the first time on July 19. In fact, such differentials had reached the 3,000 MW level three times in June and three times in July before July 19. In retrospect, the developing pattern of actual versus scheduled power flow differentials and LMP differentials between the interfaces in June and in July could have formed the basis for earlier action to correct interface pricing.

Observed differences in actual and scheduled flows at the two interfaces were the result of actions designed to exploit differences between the way in which PJM LMPs are determined and artificial contract paths existing in areas to the west and south of PJM. Absent the pricing notice that PJM issued, contracts with similar, or even identical, flow patterns (e.g. sourced at the same ECAR generation) would receive different prices if they were scheduled based on different contract paths. Contracts scheduled consistent with actual flows, on the most direct path to PJM (at the PJM/AEP interface), would receive a substantially lower price than contracts artificially scheduled inconsistent with actual flows (at the PJM/VAP interface).

Once the seriousness of the situation had been identified, it made sense to act to end the identified practice. PJM corrected the interface pricing prospectively, ensuring that transactions are paid based on flows, not artificial contract paths around PJM, as LMP requires. The result of aligning interface prices with actual power flows was to create market forces that acted to substantially reduce the identified problem.

The PJM interface pricing notice had the desired effect immediately after its implementation and continued to do so through the balance of the year. Both the actual power flow versus scheduled flow differential and the PJM/VAP versus PJM/AEP price differential density and peak values have returned to near April through May levels.

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

	Apr-02	May-02	Jun-02	Jul-02	July 1 thru 19, 2002	July 20 thru 31, 2002	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
Peak Hours Period											
$PJM/VAP - $PJM/AEP ($/MWh)	$ 7.19	$ 6.49	$14.33	$14.06	$16.44	$9.88	$10.12	$4.86	$7.36	$5.57	$11.70
PJM/VAP Act - Sch (MW)	-533	-748	-1,323	-1,327	-1,577	-891	-295	-507	-641	-668	-955
PJM/AEP Act - Sch (MW)	904	1,042	1,561	1,442	1,821	780	359	479	673	606	715
Off-Peak Hours Period											
$PJM/VAP - $PJM/AEP ($/MWh)	$5.13	$0.01	$4.87	$6.16	$7.41	$4.38	$4.39	$3.94	$6.49	$3.61	$8.56
PJM/VAP Act - Sch (MW)	-582	-460	-346	-364	-457	-229	-346	-205	-299	-574	-809
PJM/AEP Act - Sch (MW)	740	459	457	476	633	251	457	223	504	687	778

Figure 3-2 PJM/AEP and PJM/VAP:
Actual - Schedule Interface Differentials and LMP Differentials by Interface

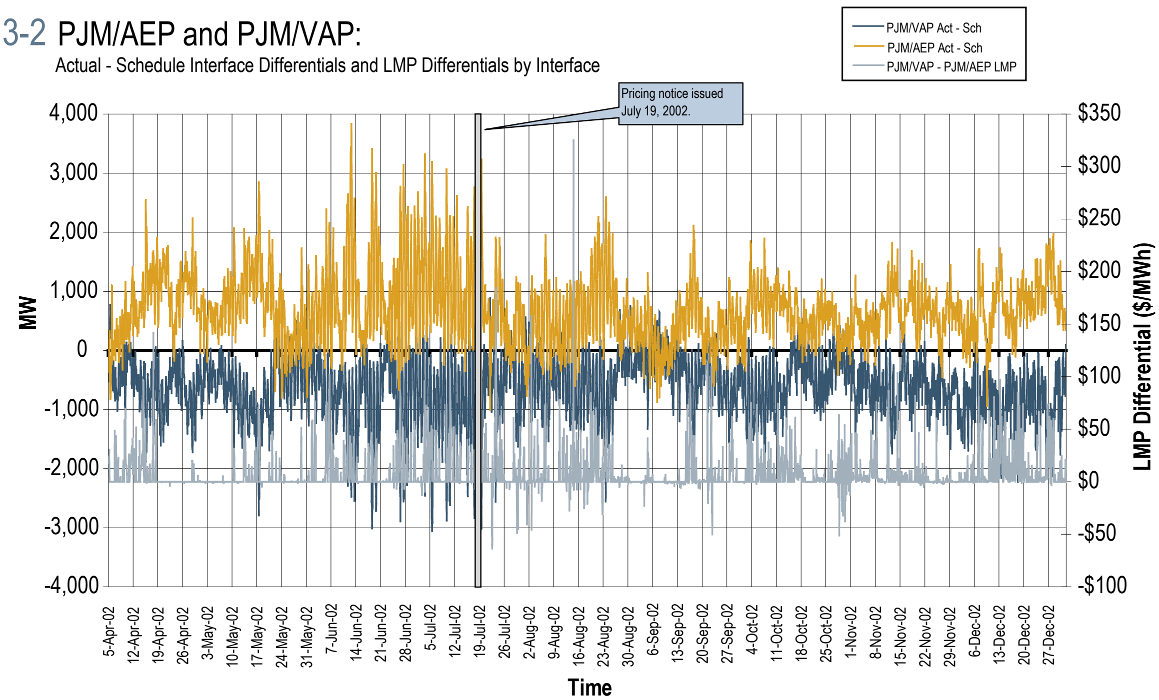
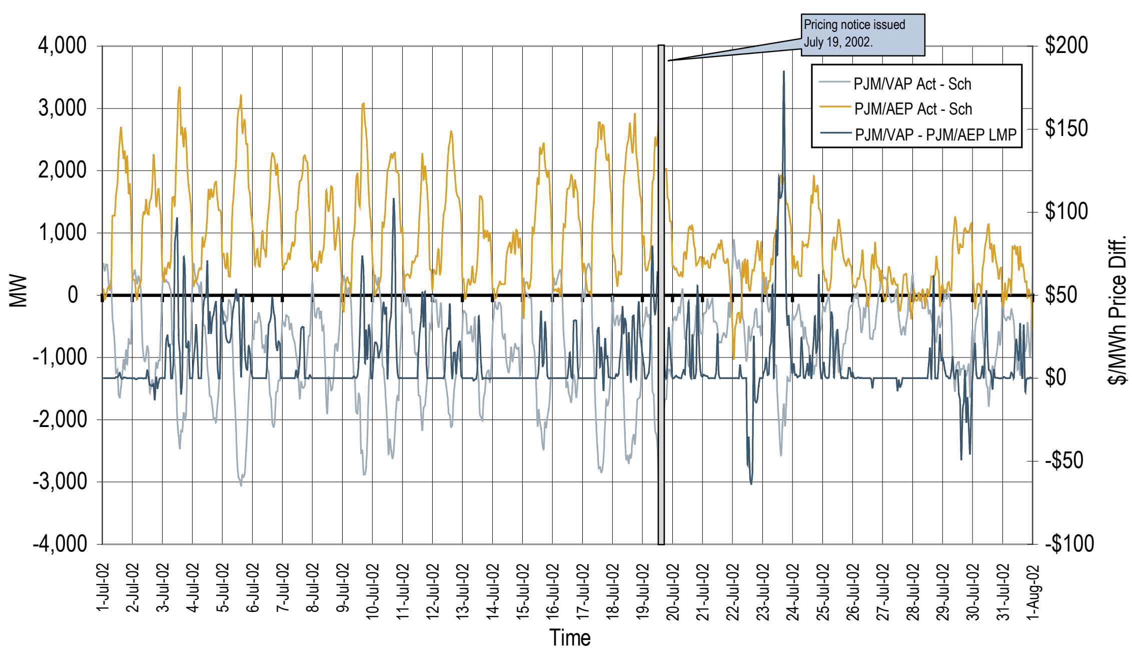


Figure 3-3 PJM/AEP and PJM/VAP:
Actual - Schedule Tie Flows and Price Differentials



AGGREGATE IMPORTS AND EXPORTS

PJM was a net importer of energy on a monthly basis for each month of 2002, although total PJM monthly net import volume declined in the second half of 2002 (Figure 3-4). PJM market participants import and export energy primarily in the real-time market. Approximately 85 percent of total gross imports and 93 percent of total gross exports take place in the real-time market without corresponding day-ahead transactions.

Figure 3-4 PJM Imports and Exports -- 2002

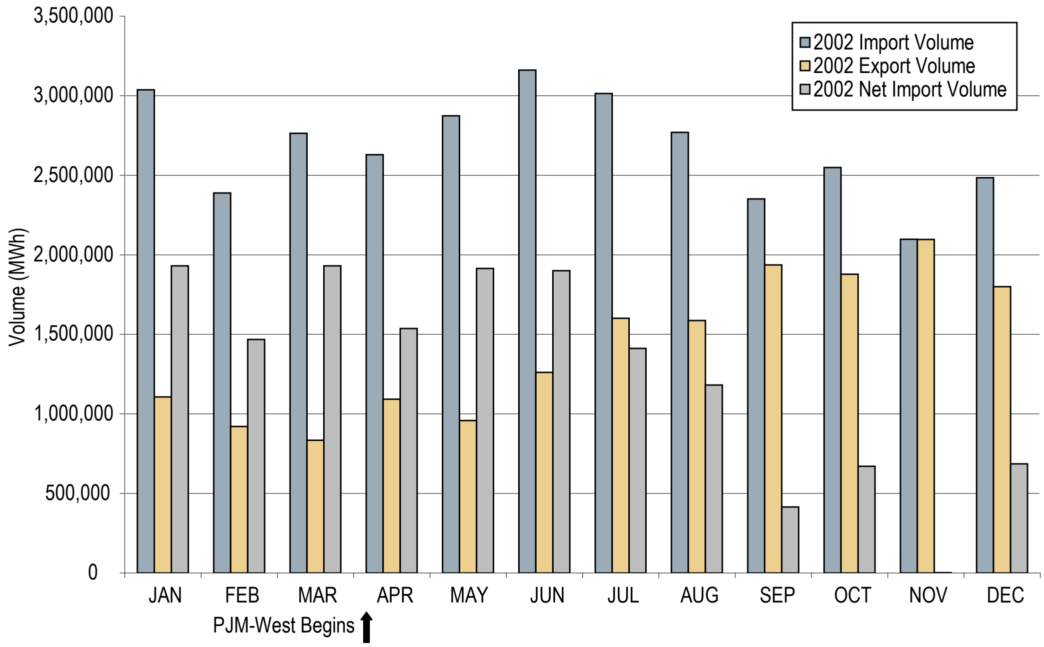
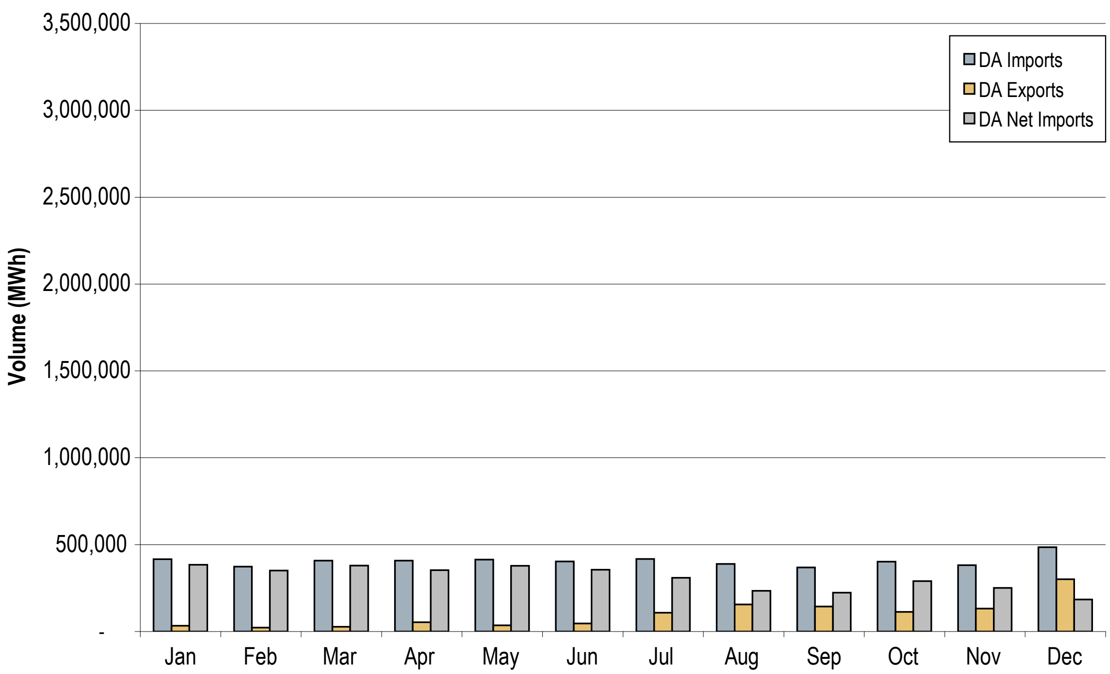


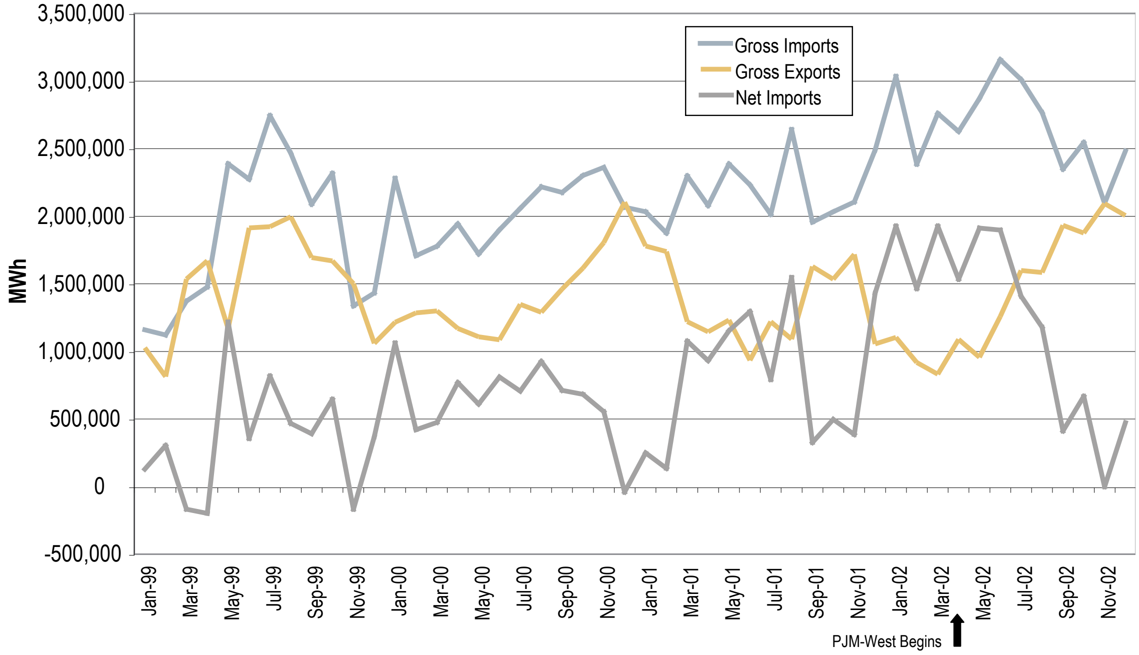
Figure 3-5 Total Day-Ahead Import and Export Volume -- 2002



Day-ahead market imports, exports and net imports are shown in Figure 3-5.

Gross imports and exports show different patterns. Gross imports have been increasing since 1999 (Figure 3-6). Although gross exports have been relatively flat since 1999, exports have increased since the addition of the PJM-West Region (Figure 3-6).

Figure 3-6 PJM Imports and Exports

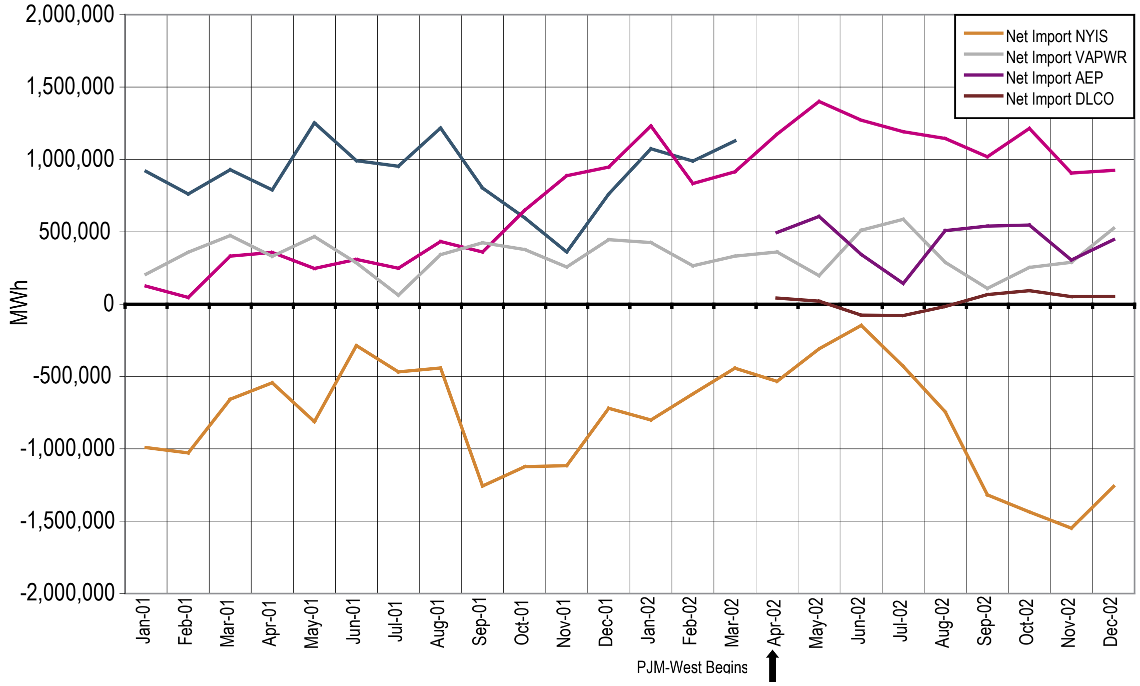


INTERFACE IMPORTS AND EXPORTS

Total imports and exports are comprised of flows at each of the five interfaces. Net imports by interface are shown in Figure 3-7 for interfaces before and after the addition of the PJM-West Region. The bulk of PJM's net imports occur at the PJM/FE interface while net exports occur regularly only at the PJM/NYIS interface. In 2002, the PJM/FE interface accounted for approximately 53 percent of total net imports. The PJM/NYIS interface carried approximately 98 percent of the net export volume. While PJM/FE net imports have been relatively flat since the addition of the PJM-West Region, there has been an increase in net exports at the PJM/NYIS interface. The combination resulted in a decrease in system net imports during the time after the PJM-West Region was incorporated into the PJM-East Region.

After a rise in net imports beginning in October 2001, net imports at the PJM/FE interface leveled off. Exports to NY increased in the second half of 2002. Net imports from PJM/VAP continued to exhibit about the same annual total volume in 2002 as 2001, but with a mid-year change in flows. This is discussed in more detail above under Interface Pricing Issue.

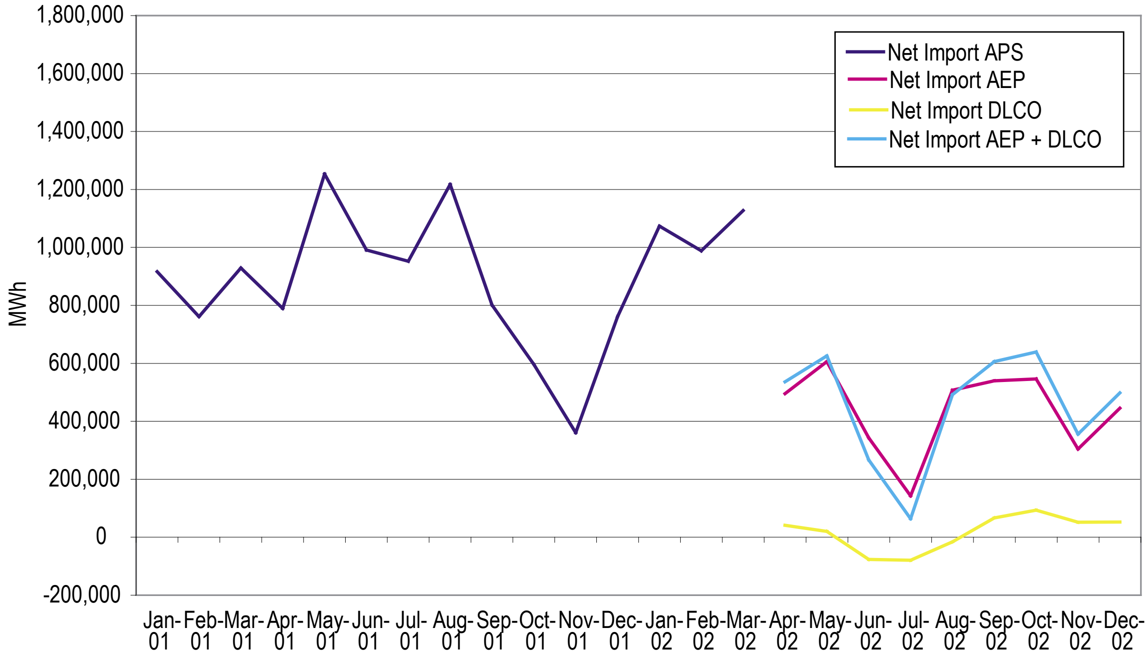
Figure 3-7 Interface Net Imports



As a result of the addition of the PJM-West Region, the PJM/AEP and PJM/DLCO interfaces replaced the PJM/APS interface. A comparison of net imports at PJM/AEP and PJM/DLCO shows that the combined net imports at these interfaces after April 1, 2002, were less than the net imports at the PJM/APS interface prior to April 1 (Figure 3-8). For the period April through December 2002, the average monthly net imports of the combined PJM/AEP and PJM//DLCO interfaces were approximately 450,000 MWh. For the same period in the prior year, the APS average monthly net imports had been approximately 860,000 MWh.

In effect, the addition of the PJM-West Region resulted in the internalization of approximately 410,000 MWh per month of what had been PJM/APS net imports. This represented approximately 48 percent of the previous PJM/APS volume.

Figure 3-8 PJM/APS, PJM/AEP and PJM/DLCO Net Imports



The individual interface gross import and export volumes are presented in Figures 3-9 and 3-10. The highest level of gross imports occurred on the PJM/FE tie (about 38 percent of the pre-PJM-West Region and 48 percent of the post-PJM-West Region imports occurred at the PJM/FE interface), while gross imports at the PJM/AEP and PJM/VAP interfaces were each about half the level of PJM/FE. The PJM/DLCO and PJM/NYIS interfaces have had the lowest gross import volumes. Gross exports occurred primarily at the PJM/NYIS tie. Approximately 76 percent of the pre-PJM-West Region and 66 percent of the post-PJM-West Region exports at the PJM/NYIS interface. The monthly average gross export volume at the PJM/NYIS interface over the past two years has been approximately 970,000 MWh while the monthly average export volume for all the other tie lines together has been about 500,000 MWh.

Figure 3-9 Interface Gross Imports

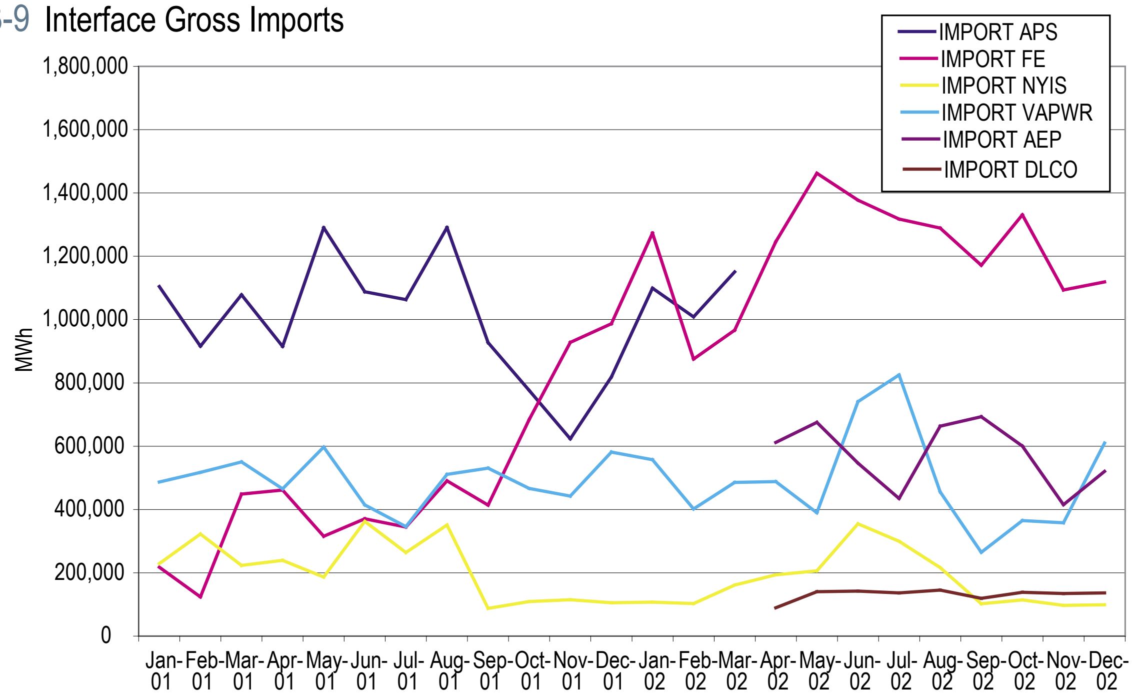
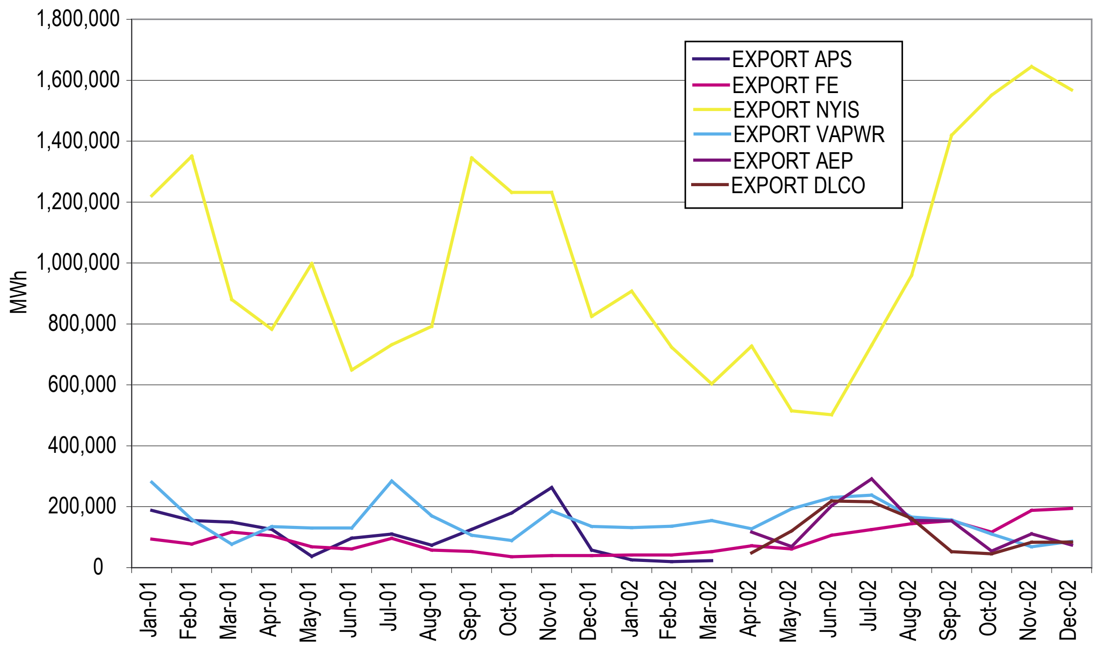
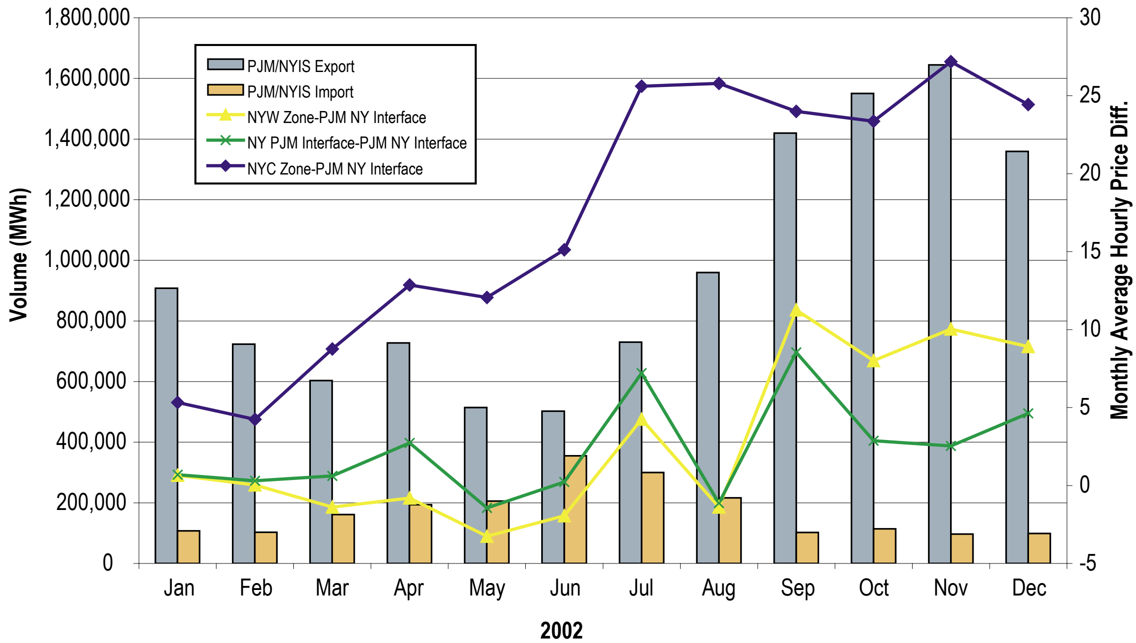


Figure 3-10 Interface Gross Exports



The increase in gross exports occurred primarily at the PJM/NYIS tie. While the reasons for this increase are complex, the addition of PJM-West and the associated reduction of the cost of transmission between areas to the west of PJM and the NYISO was a factor and there was also a corresponding increase in the monthly average hourly price differential between prices in the NYISO and PJM.

Figure 3-11 Price Differential and NYIS Export Volume
JAN-DEC 2002



SECTION 4—CAPACITY MARKETS

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

The PJM capacity credit market provides a mechanism to balance the supply and demand of capacity that is not met via the bilateral market or self-supply. The PJM capacity credit market consists of the daily, interval, monthly and multi-monthly capacity credit markets. The capacity credit market is intended to provide 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. The PJM daily capacity credit market permits LSEs to match capacity resources with short-term shifts in retail load while interval, monthly and multi-monthly capacity credit markets provide a mechanism to match longer-term obligations with capacity resources.

While designed to meet the same reliability objectives, the PJM-West Region's capacity obligations are structured differently than those in the PJM-East Region. The overall capacity obligation associated with load in the PJM-East Region is defined for an annual period.[2] The overall capacity obligation associated with load in the PJM-West Region is defined daily.

OVERVIEW

The PJM Market Monitoring Unit (MMU) analyzed key measures of capacity market structure and performance for 2002, including concentration ratios, prices, outage rates and reliability. The MMU found serious market structure issues, but no exercise of market power during 2002. The PJM-East Region's capacity market results were competitive during 2002. The PJM-West Region's capacity market results were consistent with a reasonably competitive outcome although there is not a functioning competitive market in the PJM-West Region. Market power remains a serious concern for the MMU in both capacity markets.

Market Structure – The PJM-East Region

- **Supply.** Structural analysis of the PJM-East Region's capacity credit market found that short-term and long-term markets exhibited high concentration levels in 2002.
- **Demand.** During 2002, the original PJM-East Region electric utilities and their affiliates accounted for 92 percent of the PJM-East Region's load obligations.
- **Supply and Demand.** During 2002, installed capacity, unforced capacity and obligations grew in the PJM-East Region. Average installed capacity increased by 3,522 MW, or 6.0 percent, to 62,380 MW, while average unforced capacity rose by 6.4 percent to 59,363 MW. Average load obligations climbed by 3,070 MW, or 5.6 percent, to 57,557 MW, or 1,806 MW less than average unforced capacity. Overall capacity credit market transactions increased by nearly 73 percent. Daily capacity credit market volume declined by 46 percent, while

1 See "Glossary" for definitions of capacity credit market terms.

2 The peak load is established once per year, effective in January, and the associated capacity obligation changes again in June when the installed reserve margin and the forecast pool requirement are determined.

monthly and multi-monthly capacity credit market volume increased by 28 percent and 311 percent, respectively.

Market Structure – The PJM-West Region

- **Supply.** The structural analysis of the PJM-West Region's capacity credit markets found that capacity credit markets exhibited extremely high concentration levels in 2002.
- **Demand.** During 2002, the original PJM-West Region electric utility accounted for 99.9 percent of the PJM-West Region's load obligations.
- **Supply and Demand.** In 2002, the PJM-West Region's average installed capacity was 10,014 MW and the average available capacity was 8,467 MW. The average capacity obligation was 6,823 MW while the maximum capacity obligation was 8,987. The capacity credit market was effectively not operating after June.

Market Performance – The PJM-East Region

- **Prices.** Daily capacity credit market prices were quite low during 2002, averaging $0.59 per MW-day. Prices in the interval, monthly and multi-monthly markets declined over the year from $67.20 per MW-day in January to $12.50 per MW-day in December, averaging $38.21 per MW-day. In both cases, prices reflected supply-demand fundamentals and were nearer competitive levels than during 2001.

Market Performance – The PJM-West Region

- **Prices.** Daily capacity market prices averaged $84.03 per MW-day. Prices in the interval, monthly and multi-monthly markets averaged $10.31 per MW-day. Prices spiked in the daily markets on several occasions.
- **Volumes.** There was very little activity in the capacity credit markets, particularly after June.

Given the basic features of the capacity market structure in both PJM-East and PJM-West 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. Market power is structurally endemic to PJM capacity markets. Supply and demand fundamentals offset these market structure issues in the PJM-East capacity market in 2002, producing competitive results. In the PJM-West capacity market, the dominance of a single supplier and the extremely small load levels served by independent LSEs meant that there was not a functioning competitive market. After June, the small number of LSEs entered into bilateral contracts, resulting in a non-existent market. The price spikes in the PJM-West daily capacity market in the pre-June period were addressed directly with the relevant market participants by the MMU. The actual results in the PJM-West capacity market were consistent with a reasonably competitive outcome despite the absence of a functioning competitive market.

The MMU is also 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 recommends that PJM implement a single capacity market design across all parts of PJM.

MARKET STRUCTURE
PJM-EAST REGION

Supply Side

Concentration ratios[3] are a summary measure of market share, a key element of market structure. High concentration ratios mean that a comparatively small number of sellers dominates a market, while low concentration ratios mean that a larger number of sellers shares market sales more equally. Concentration measures must be applied carefully in assessing the competitiveness of markets. Low aggregate market concentration ratios do not establish that a market is competitive, that market participants cannot exercise market power or that concentration is not high in particular geographical market areas. High aggregate market concentration ratios do, however, indicate an increased potential for market participants to exercise market power.

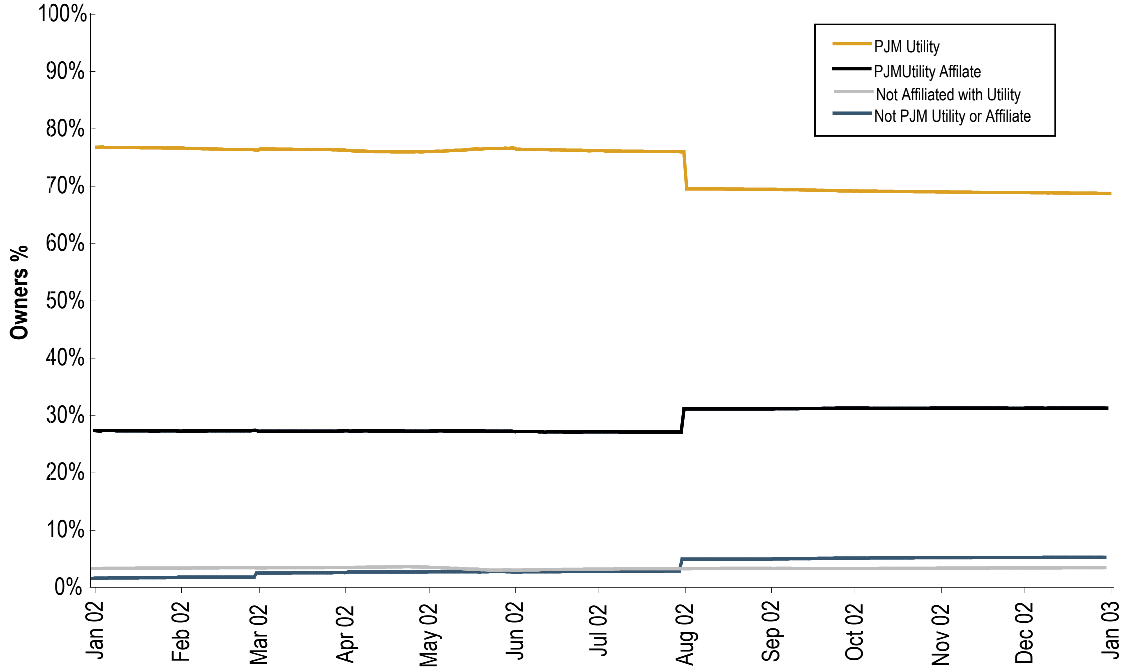
The MMU structural analysis indicates that overall, the PJM-East Region's capacity credit markets in 2002 exhibited high levels of concentration. Herfindahl-Hirschman Indices (HHIs) for the daily capacity credit markets averaged about 2400 during 2002, with a maximum of about 4500 and a minimum of about 1200 (Four firms with equal market shares would result in an HHI of 2500). HHI for the longer-term, interval, monthly and multi-monthly capacity credit markets averaged about 3200, with a maximum of 8000 and a minimum of more than 1400 (Three firms with equal market shares would result in an HHI of 3333).

Demand Side

During 2002, PJM electric utility companies (the original PJM electric utilities) and their affiliates maintained their market share of PJM-East Region's load obligations, averaging 92 percent. The market share of PJM electric utility companies averaged 72 percent of the PJM-East Region's load. As Figure 4-1 shows, market share of the affiliates of PJM electric utilities averaged 20 percent. The market share of load-serving entities not affiliated with a utility was four percent and the market share of non-PJM utilities and their affiliates averaged about four percent.

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

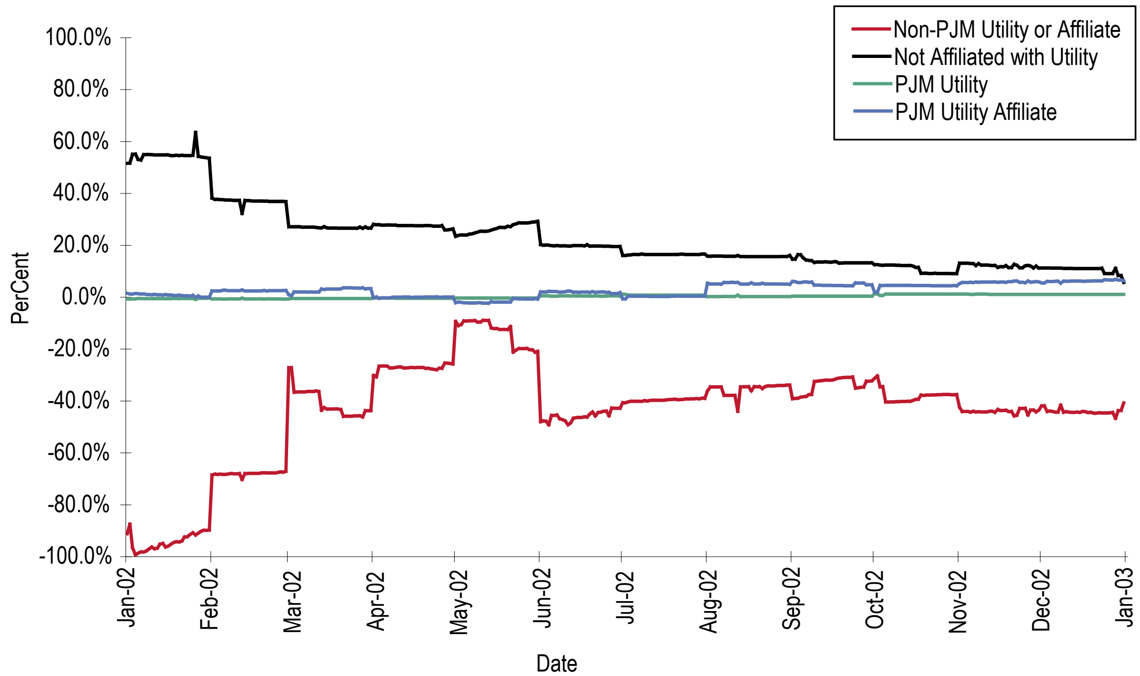
Figure 4-1 Percent of the PJM-East Region's Load Obligation Served in 2002



During 2002, reliance on the PJM-East Region's capacity credit markets varied by sector. As Figure 4-2 shows, PJM electric utilities relied on capacity credit markets for an average of 0.3 percent of their 2002 unforced capacity obligation while their affiliates relied on capacity credit markets for an average of 2.8 percent of theirs. Affiliates of non-PJM electric utilities obtained an average of -43.5 percent of their unforced capacity obligations from the capacity credit markets while unaffiliated load-serving entities obtained an average of 22.6 percent of their capacity obligations from the capacity credit markets. The measure of capacity credit market reliance is the sector's daily net capacity credit market position divided by the sector's capacity obligation (This excludes self-supply and bilateral transactions). Thus, a negative share means that a sector has sold more capacity credits than it has purchased for a day.

During 2002, the reliance of LSEs not affiliated with utilities on the capacity credit markets diminished from approximately 55 percent to about six percent. The proportion of load obligation served in the capacity credit markets fluctuated for non-PJM utilities and their affiliates based on changes in capacity obligations and activity in the capacity credit markets.

Figure 4-2 Load Obligation Served by the PJM-East Region Capacity Credit Market



Supply and Demand

In 2002, capacity resources exceeded capacity obligations in the PJM-East Region on every day. The pool was long by an average 1,806 MW. The amount of capacity resources in the PJM-East Region on any day reflects the addition of new resources and retirement of old ones, and the importing or exporting of capacity resources, decisions that are functions of market forces. The total pool capacity obligation is set annually via an administrative process.

System net excess capacity can be determined using unforced capacity, obligation, the sum of members' excesses, and the sum of members' deficiencies. Table 4-1 presents these data for 2002.[4] Net excess is the net pool position, calculated by subtracting obligations from capacity resources. Since obligations include expected load plus a reserve margin, a net pool position of zero is consistent with established reliability objectives.

4 These data are posted on a monthly basis at www.pjm.com under the Market Monitoring Unit link. Each item presented in this Section 4 is a PJM-East Region system total, and, unless otherwise noted, expressed in MW of unforced capacity.

Table 4-1—PJM-East Region Member Capacity Summary (January to December 2002, in MW)

PJM-East Region	Mean	Standard Deviation	Minimum	Maximum	MW Change from 2001	Percent Change from 2001
Installed Capacity	62,380	925	60,698	64,055	3,522	6.0%
Unforced Capacity	59,363	863	57,760	60,886	3,577	6.4%
Obligation	57,557	786	56,361	58,224	3,070	5.6%
Sum of Excess	1,841	436	682	2,681	359	24.2%
Sum of Deficiency	35	68	0	389	-149	-80.9%
Net Excess	1,806	425	682	2,681	507	39.1%
Imports	1,328	328	729	1,665	589	79.7%
Exports	761	511	240	1,937	92	13.8%
Net Exports	-567	608	-1,425	594	-497	707.5%
Unit-Specific Transactions	37,093	7,518	28,005	45,384	9,880	36.3%
Capacity Credit Transactions	55,419	9,383	41,515	65,516	23,296	72.5%
Internal Bilateral Transactions	92,512	16,765	69,541	109,437	33,176	55.9%
Daily Capacity Credits	450	207	11	880	-379	-45.7%
Monthly Capacity Credits	848	449	416	2,021	186	28.0%
Multi-Monthly Capacity Credits	2,196	349	1,527	2,670	1,662	311.1%
All Capacity Credits	3,494	481	2,557	4,430	1,469	72.5%
ALM Credits	1,569	331	1,275	1,962	-282	-15.2%

As shown in Figures 4-3 and 4-4, capacity owners increased external sales of capacity resources for the summer period even though the external daily forward energy prices were generally less than the PJM-East Region's prices. The PJM-East Region's price in these graphs is the firm, daily forward on-peak PJM-East Region Western Hub energy price, while the external price is the firm, daily forward on-peak price for Cinergy.[5]

5 These daily forward prices are on-peak prices.

Figure 4-3 The PJM-East Region's Capacity Obligations

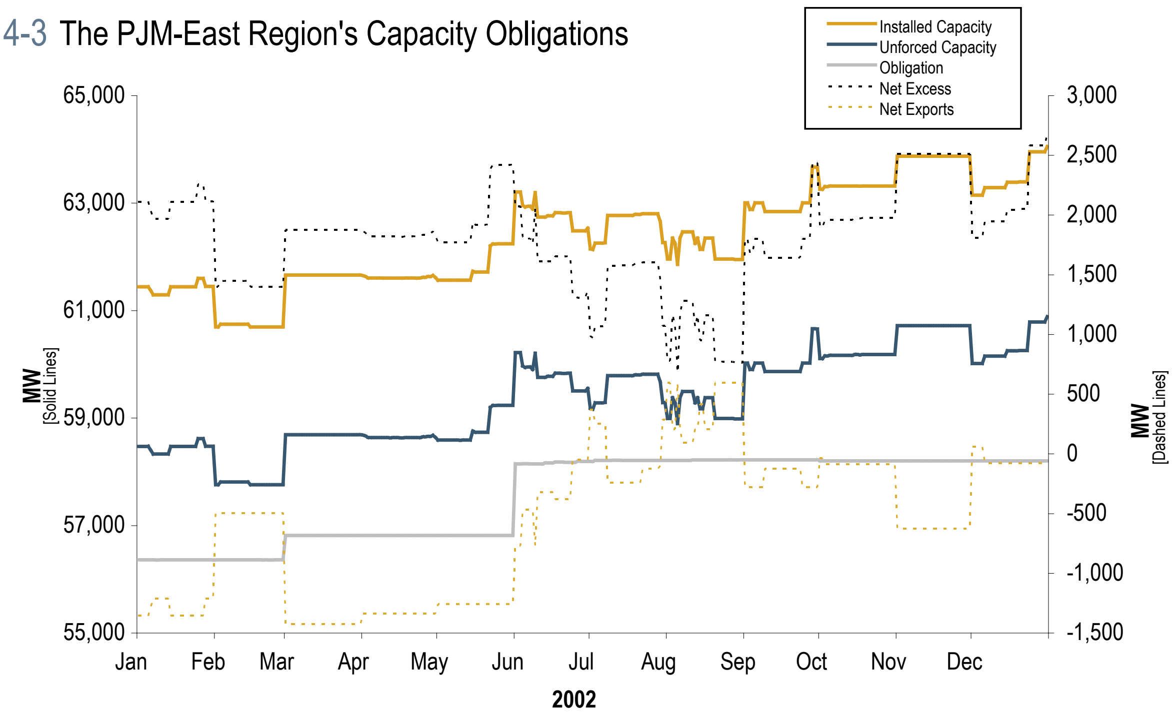
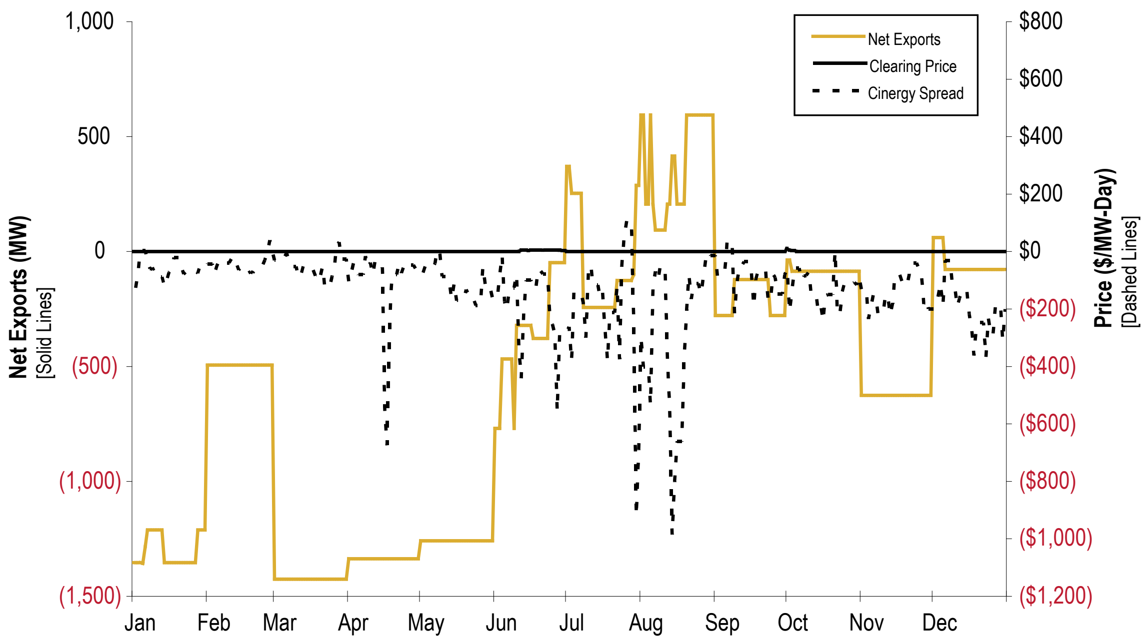


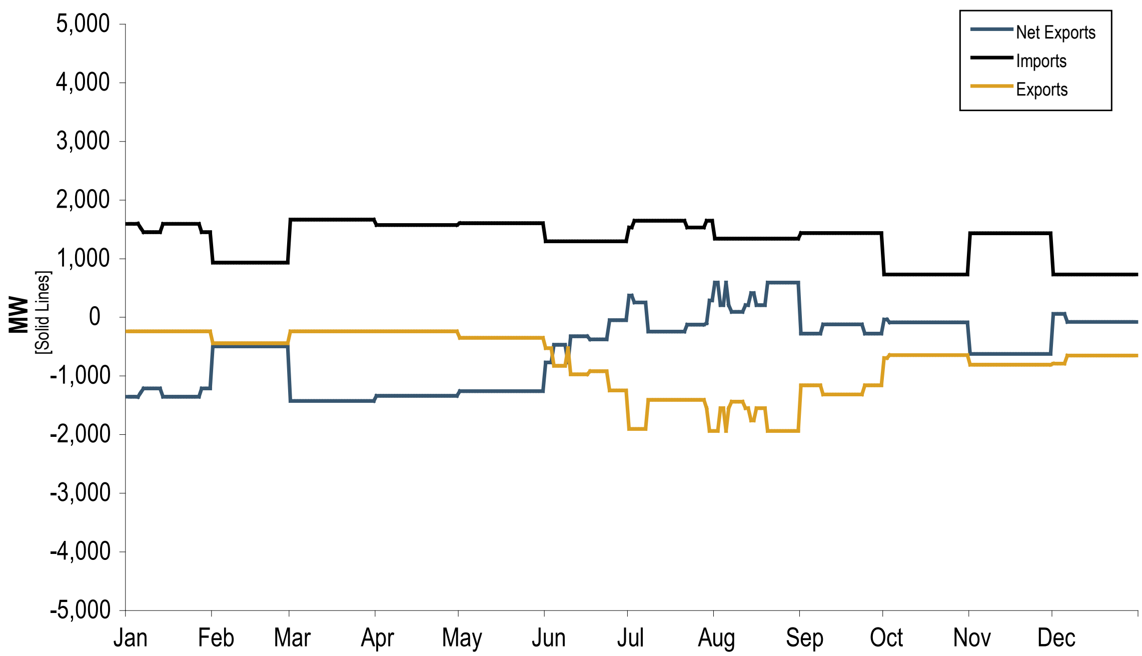
Figure 4-4 The PJM-East Region's Daily CCM Clearing Price and Cinergy Spread versus Net PJM-East Region Exports



External Capacity Transactions

PJM-East Region capacity resources may be traded bilaterally within and outside of the PJM-East Region. Table 4-1 and Figure 4-5 present PJM-East Region bilateral capacity transaction data for 2002. An average of 1,328 MW of capacity resources was imported into the PJM-East Region and an average of 761 MW was exported (delisted) for an average net import of 567 MW of capacity resources during the period. The maximum export (delist) was 1,937 MW, while the maximum import was 1,665 MW. Compared to 2001, imports rose by 80 percent and exports increased by 14 percent.

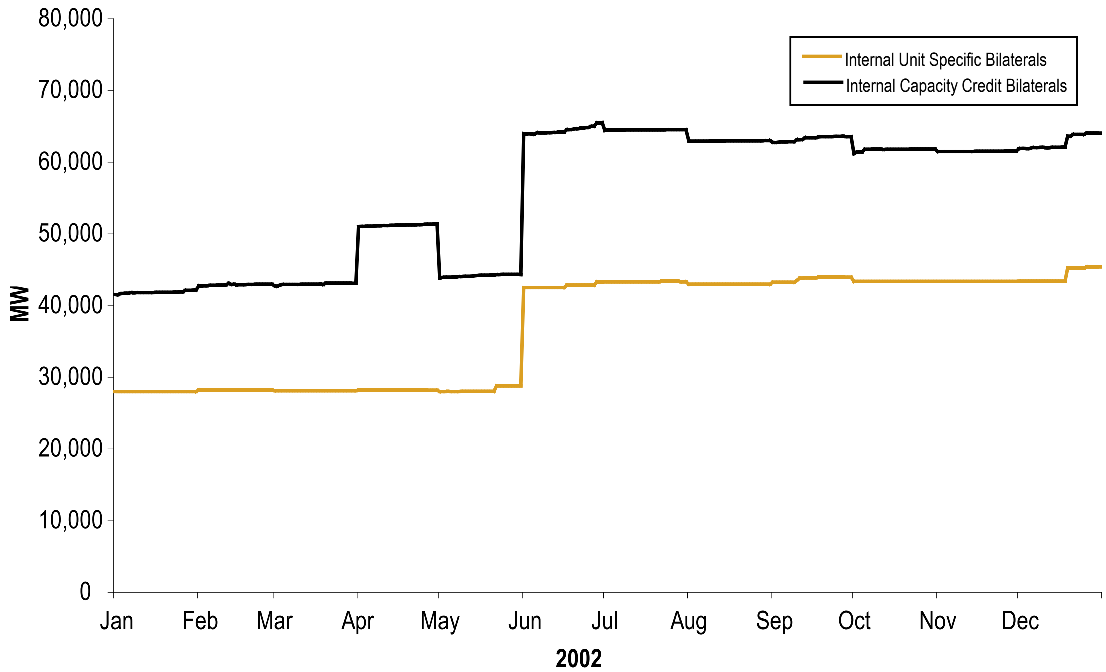
Figure 4-5 The PJM-East Region's External Transactions 2002



Internal Bilateral Transactions

Internal, unit-specific transactions in 2002 were about 36 percent higher than they had been in 2001. Internal capacity credit transactions in 2002 were about 73 percent higher than they had been in 2001. As can be seen from Figure 4-6, bilateral transactions increased on June 1, 2002, coinciding with the beginning of the PJM Planning Period.

Figure 4-6 The PJM-East Region's Bilateral Transactions 2002



Active Load-Management Credits

Active Load-Management (ALM) reflects the ability of individual customers, under contract with their Load-Serving Entity, to reduce specified amounts of load during an emergency declared in the PJM-East Region. ALM credits, measured in MW of curtailable load, reduce LSE capacity obligations. ALM credits in the PJM-East Region averaged 1,569 MW in 2002, down approximately 15 percent from 1,851 MW in 2001 (Table 4-1). ALM participation appeared to decline because participants shifted to competing PJM DSM programs.

PJM-WEST REGION

Supply Side

The structural analysis indicates that the PJM-West Region's capacity credit markets exhibited extremely high levels of concentration in 2002. HHI for the shorter-term, daily capacity credit markets averaged about 9100 during 2002, with a maximum of 10000 and a minimum of about 4000 (A single firm with 100 percent market share would result in an HHI of 10000 and two firms with equal market shares would result in an HHI of 5000). HHI for interval, monthly and multi-monthly capacity credit markets averaged about 8200, with a maximum of 10000 and a minimum of approximately 3300 (Three firms with equal market shares would result in an HHI of 3333).[6]

Demand Side

During 2002, electric utility companies supplied nearly 100 percent of the PJM-West Region's load obligations. The market share of the electric utilities ranged from 99.95 percent to 99.98 percent, and averaged 99.97 percent. The market share of unaffiliated companies was negligible, averaging 0.03 percent.

During 2002, reliance on the PJM-West Region's capacity credit markets varied by sector. Electric utilities relied on capacity credit markets for an average of 0.5 percent of their 2002 available capacity obligation. Non-affiliated companies relied heavily on the capacity credit markets through mid-June and effectively not at all after mid-June. There was very little load served by LSEs other than the local electric utility. LSEs not affiliated with the local electric utility served an average of about three percent of the maximum daily PJM-West Region obligation of 8,987 MW.

Supply and Demand

Capacity resources exceeded capacity obligations by approximately 1,600 MW in the PJM-West Region, on average, after April 1, 2002 (Table 4-2). The PJM-West Region was capacity deficient on two days in 2002.

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

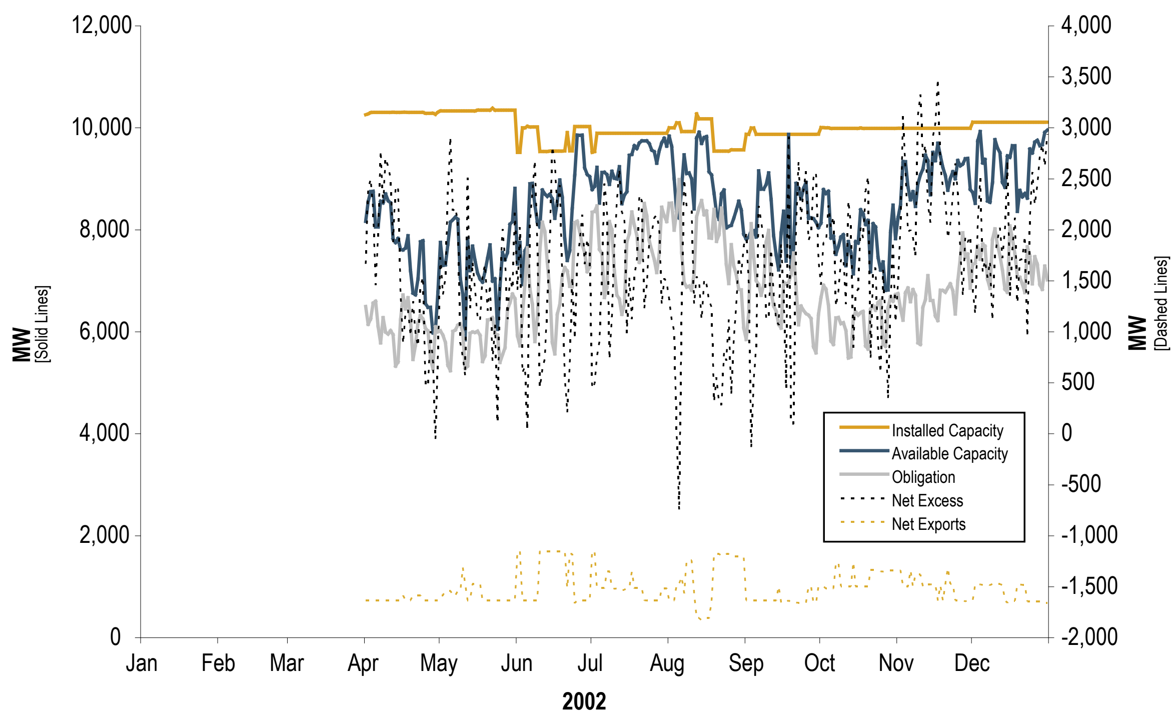
System net excess capacity can be determined using available capacity (installed capacity adjusted for all current outages), obligation, the sum of members' excesses, and the sum of members' deficiencies. Table 4-2 presents these data for 2002. Net excess is the net PJM-West Region position, calculated by subtracting system Day-Ahead Capacity Obligation (DACO) from total capacity resources. System DACO includes expected daily load plus six percent. Thus a net PJM-West Region position of zero is consistent with established reliability objectives.

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

Table 4-2—PJM-West Region Member Capacity Summary (April to December 2002, in MW)

PJM-West Region	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	10,014	225	9,520	10,383
Available Capacity	8,467	899	5,847	9,958
Obligation	6,823	830	5,236	8,987
Sum of Excess	1,648	717	0	3,480
Sum of Deficiency	4	46	0	752
Net Excess	1,644	726	-752	3,480
Imports	1,594	162	1,241	1,896
Exports	80	12	42	89
Net Exports	-1,513	160	-1,831	-1,152
Unit-Specific Transactions	2,087	912	181	3,073
Capacity Credit Transactions	66	96	0	481
Internal Bilateral Transactions	2,152	864	411	3,101
Daily Capacity Credits	3	12	0	118
Monthly Capacity Credits	27	78	0	250
Multi-Monthly Capacity Credits	0	0	0	0
All Capacity Credits	30	81	0	306
QIL Credits	0	0	0	0

Figure 4-7 The PJM-West Region's Capacity Obligations

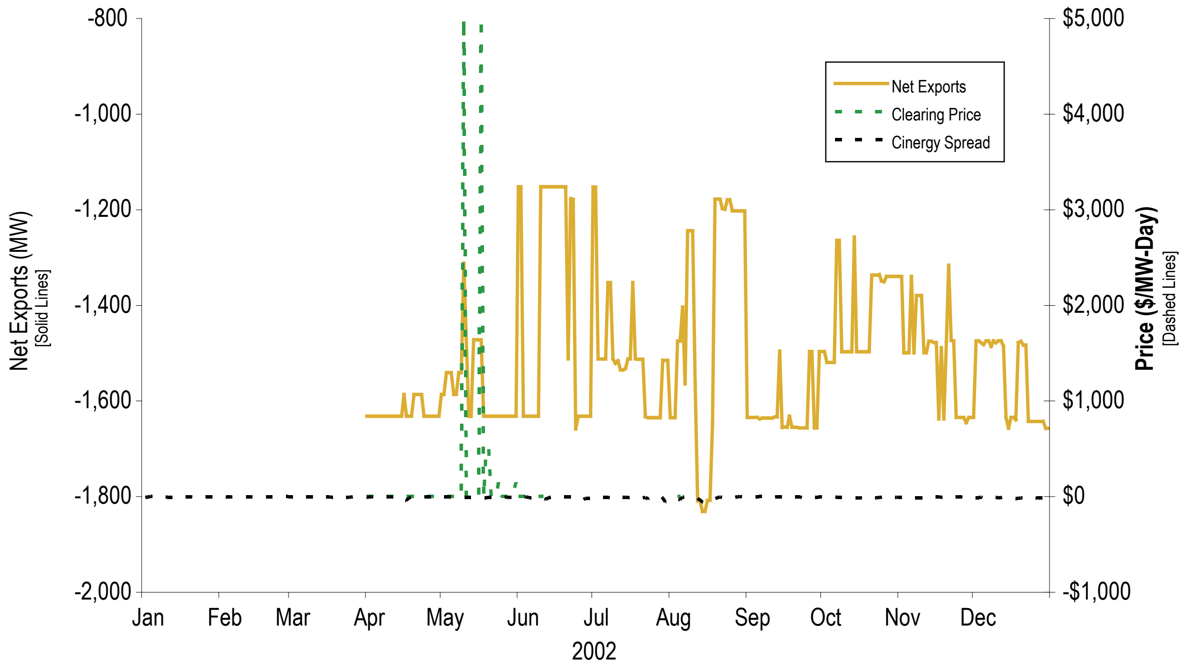


As shown in Figures 4-7 and 4-8, exports of capacity resources for the summer period averaged about 1,500 MW even though the external daily forward energy prices were generally less than PJM-West Region prices. The PJM-West Region price in these graphs is the firm, daily forward on-peak PJM Western Hub energy price, while the external price is the firm, daily forward on-peak price for Cinergy.

External Capacity Transactions

The PJM-West Region's capacity resources may be traded bilaterally within and outside of the PJM-West Region. Table 4-2 presents PJM-West Region bilateral capacity transaction data for 2002. An average of 1,594 MW of capacity resources was imported into the PJM-West Region and an average of 80 MW was exported (delisted) for an average net import of 1,513 MW of capacity resources during the period. The maximum export (delist) was 89 MW, while the maximum import was 1,896 MW.

Figure 4-8 The PJM-West Region's CCM Clearing Price and Cinergy Spread versus Net PJM-West Region Exports



MARKET PERFORMANCE
PJM-EAST REGION

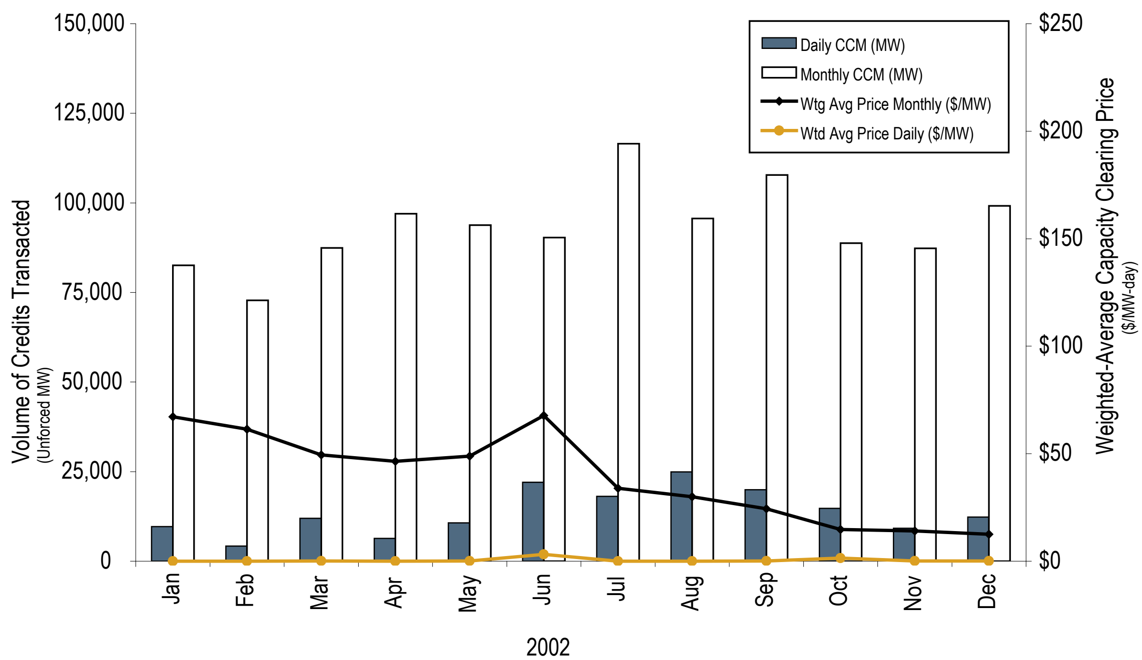
Capacity Credit Markets

PJM operated daily, monthly and multi-monthly capacity credit markets throughout 2002. As Table 4-1 shows, the daily capacity credit market averaged 450 MW of transactions, or about 0.8 percent of the average capacity obligations for the period. Trading in the PJM-East Region's daily capacity credit markets declined compared to activity in the market in 2001.

Prices

Table 4-3 shows prices and volumes in both the daily and the longer-term capacity credit markets. The volume-weighted average price for 2002 was $38.21 per MW-day in the monthly and multi-monthly capacity credit markets and was $0.59 per MW-day in the daily capacity credit markets. The volume-weighted average price for all capacity credit markets was $33.40 per MW-day.[7] Prices in the daily capacity credit market were relatively constant during the year and declined in the interval, monthly and multi-monthly markets (Figure 4-9). Prices in the capacity credit markets in 2002 were significantly lower overall than in 2001. The volume-weighted average of all capacity credit markets was $52.86 per MW-day in 1999, $60.55 in 2000 and $95.34 in 2001. Prices in the monthly and multi-monthly capacity credit markets were $70.66 per MW-day in 1999, $53.16 in 2000 and $100.43 in 2001, while the daily capacity credit market price averaged $3.63 per MW-day in 1999, $69.39 in 2000 and $87.98 in 2001.

Figure 4-9 The PJM-East Region's Daily and Monthly Capacity Credit Market Performance 2002



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

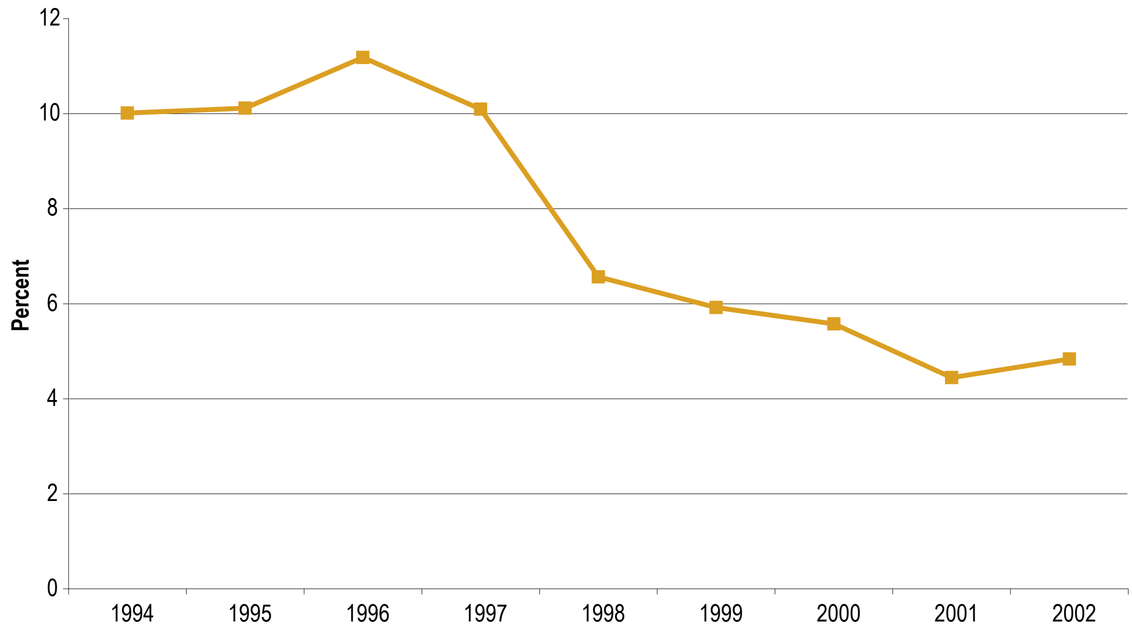
Table 4-3—PJM-East Region Capacity Credit Market

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-02	9,653	82,600	92,253	$0.01	$67.20	$60.17
Feb-02	4,240	72,786	77,026	$0.00	$61.35	$57.97
Mar-02	11,959	87,439	99,398	$0.10	$49.43	$43.50
Apr-02	6,378	96,993	103,371	$0.01	$46.43	$43.56
May-02	10,672	93,815	104,488	$0.05	$48.88	$43.89
Jun-02	22,056	90,312	112,368	$3.15	$67.72	$55.05
Jul-02	18,104	116,548	134,651	$0.03	$33.89	$29.34
Aug-02	24,912	95,663	120,575	$0.05	$30.02	$23.83
Sep-02	19,974	107,784	127,758	$0.05	$24.40	$20.59
Oct-02	14,751	88,769	103,520	$1.46	$14.70	$12.81
Nov-02	9,176	87,342	96,518	$0.05	$14.04	$12.71
Dec-02	12,317	99,188	111,504	$0.05	$12.50	$11.13
For 2002	164,193	1,119,237	1,283,430	$0.59	$38.21	$33.40

Availability

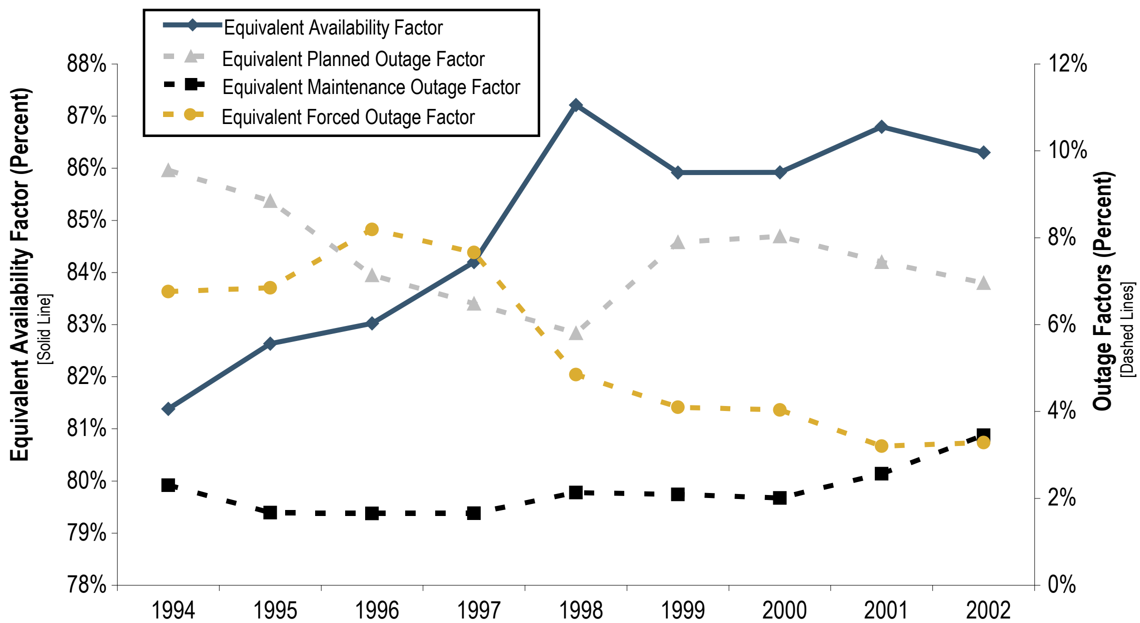
Unforced capacity from a specific unit is based on both the maximum summer capability of the unit and the forced outage rate. The installed capacity market creates an incentive to minimize the forced outage rate because the amount of capacity resources available from a unit is inversely related to the forced outage rate. The equivalent demand forced outage rate (EFORd) is a statistical measure of the probability that a unit will fail, either partially or totally, to perform when it is needed. Since 1996, the average EFORd in the PJM-East Region has trended downward, reaching 4.5 percent in 2001 and has since increased slightly to 4.8 percent in 2002. Figure 4-10 shows the average EFORd since 1994. The downward trend in average EFORd has been the result both of improved performance by existing generating resources and the addition of new gas-fired turbine generators with low EFORds.

Figure 4-10 The PJM-East Region's Equivalent Demand Forced Outage Rate (EFORd)



Certain outage statistics are calculated by reference to total hours in the year rather than statistical probability. Figure 4-11 shows these performance measures for PJM-East Region units. The Equivalent Availability Factor, for example, represents the proportion of hours in a year that a unit was available to generate at full capacity. The sum of the Equivalent Availability Factor, Equivalent Maintenance Outage Factor, Equivalent Planned Outage Factor and Equivalent Forced Outage Factor equals 100 percent. The increase in Equivalent Forced Outage Factor and Equivalent Maintenance Outage Factor from 2001 to 2002 was offset by a decrease in Equivalent Planned Outage Factor. The PJM-East Region aggregate Equivalent Availability Factor was 86.7 percent in 2001 and 86.3 percent in 2002. The small change in Equivalent Availability Factor was caused by small increases in maintenance and forced outages.

Figure 4-11 The PJM-East Region's Equivalent Outage and Availability Factors



PJM-WEST REGION

PJM operated daily, monthly and multi-monthly capacity credit markets in the West beginning April 1, 2002. Consistent with the small share of the market served by non-affiliated LSEs, the daily capacity credit market averaged three MW of transactions, or about 0.04 percent of the average capacity obligations for the period (Table 4-2).[8]

Capacity Credit Market Pricing

Table 4-4 and Figure 4-12 show prices and volumes commencing April 1, 2002, in both the daily and the longer-term capacity credit markets. The volume-weighted average prices for the period were $10.31 per MW-day in the monthly and multi-monthly capacity credit markets and $84.03 per MW-day in the daily capacity credit markets. The volume-weighted average of all capacity credit markets was $17.62 per MW-day.[9]

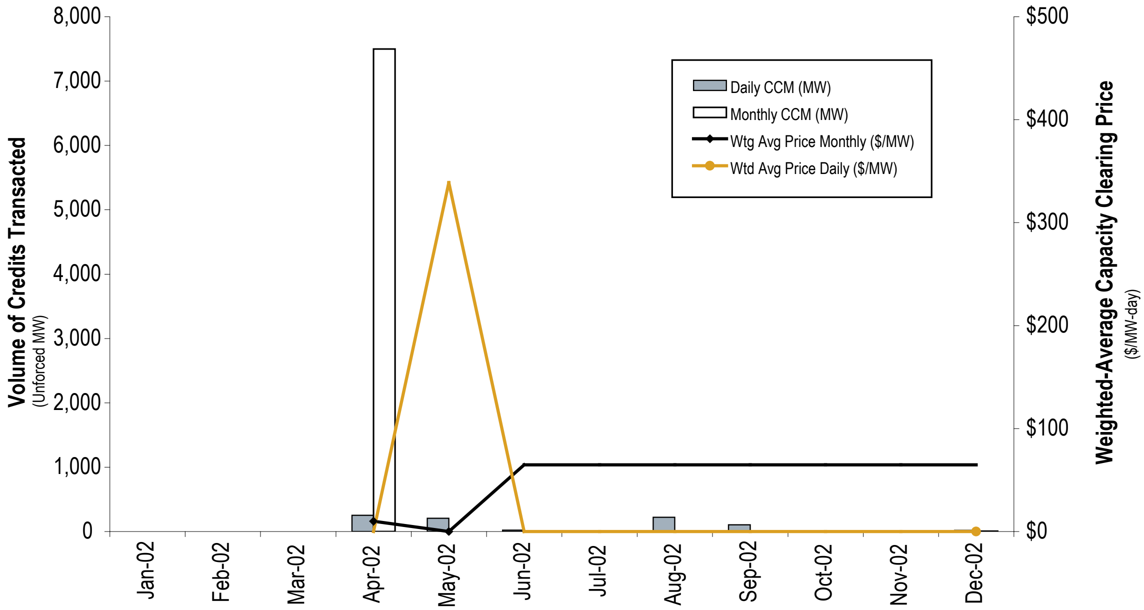
Table 4-4—PJM-West Region Capacity Credit Market

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-02	n/a	n/a	n/a	n/a	n/a	n/a
Feb-02	n/a	n/a	n/a	n/a	n/a	n/a
Mar-02	n/a	n/a	n/a	n/a	n/a	n/a
Apr-02	251	7,500	7,751	$0.00	$10.00	$9.68
May-02	206	0	206	$338.86	$0.00	$338.86
Jun-02	21	6	27	$0.00	$64.72	$14.49
Jul-02	0	6	6	$0.00	$64.72	$64.72
Aug-02	221	6	227	$0.00	$64.72	$1.77
Sep-02	105	6	111	$0.00	$64.72	$3.49
Oct-02	0	6	6	$0.00	$64.72	$64.72
Nov-02	7	6	13	$0.00	$64.72	$30.58
Dec-02	20	6	26	$0.00	$64.72	$15.49
For 2002	830	7,543	8,373	$84.03	$10.31	$17.62

7 Only limited data is provided for the PJM-West capacity market because the additional data would provide confidential information about the dominant participant in that market.

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

Figure 4-12 The PJM-West Region's Daily and Monthly Capacity Credit Market Performance



The performance of the PJM-West capacity market illustrates that this was not a market in any meaningful sense. The market was dominated on the supply side by one participant and there was very little activity on the demand side. The price spikes in the PJM-West daily capacity market in the pre-June period were anomalies resulting from the extremely thin markets, affected relatively small volumes and were addressed directly with the relevant market participants by the MMU. In the PJM-West capacity market, the small number of load-serving entities entered into bilateral contracts after June, resulting in a non-existent market.

SECTION 5—ANCILLARY SERVICE MARKETS

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

Regulation matches generation with very short-term increases and decreases in load by moving the output of selected generators up and down via an automatic control signal. Longer-term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Spinning reserves are a form of primary reserves and must be synchronized to the system and capable of providing output within 10 minutes.

The regulation market was introduced on June 1, 2000, and modified on December 1, 2002 in conjunction with the implementation of the spinning market. The spinning market was introduced on December 1, 2002.

OVERVIEW

The PJM Marketing Monitoring Unit (MMU) reviewed structure and performance indicators for the regulation market and concluded that the regulation market functioned effectively and produced competitive results in 2002. The MMU reviewed structure and performance indicators for the new spinning reserve market and concluded that, based on the very limited evidence, the spinning market functioned effectively and produced competitive results in 2002.

Regulation Market Structure

- In 2002, the PJM regulation market was characterized by moderate concentration levels, but concerns about market concentration levels were offset by the level of available regulation supply from PJM resources relative to the demand for regulation.

Regulation Market Performance

- **Price.** The market price of regulation was approximately equal to the price under the administrative, cost-based system, and the price exhibited the expected relationship to changes in demand.
- **Service Availability.** Introduction of a market in regulation resulted in significant improvement in system regulation performance during 2001 and the first part of 2002. System regulation performance declined after the addition of the PJM-West Region.

Spinning Reserve Market Structure

- Concentration is high in the Tier 2 spinning reserve market. The average Herfindahl-Hirschman Index (HHI) in December was in excess of 2500.

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

Spinning Market Performance

- **Price.** The average cost per MW associated with meeting PJM's demand for spinning reserves increased $1 per MW, or about five percent, in 2002 over 2001. The introduction of the new market in December, however, brought a month-to-month decrease of about 16 percent.

REGULATION

Regulation Market Structure

Of the 547 generating units in the PJM-East Region, 123 are qualified to provide regulation. In the PJM-East Region, there are more than 62,380 MW of generating capacity while about 1,966 MW of regulation capability have been identified in this analysis. In the PJM-West Region, there are 42 generating units and there is 10,014 MW of aggregate generating capacity. The total regulating capacity of the 21 units capable of regulating in the PJM-West Region is over 260 MW.

The PJM-East Region establishes separate, area-wide regulation requirements for both peak hours (hours ended 0600 to 2400 hours) and off-peak hours (hours ended 0100 to 0500 hours). The regulation requirement in PJM-East 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.[2] During 2002, this requirement ranged from approximately 214 MW of regulation capability for the off-peak period to approximately 627 MW for the peak period in the PJM-East Region. In PJM-West, the regulation requirement is 1.0 percent of the peak forecast load. During 2002, this requirement area ranged from 43 MW to over 83 MW in the PJM-West Region, for the off-peak and on-peak periods, respectively.

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.[3] Concentration ratios measure the concentration of ownership in a market, in this case, the ownership of regulation assets. An analysis of HHIs since the introduction of the regulation market indicates that seasonal HHIs fall between 1575 and 1763 (Table 5-1).[4]

Table 5-1—Regulation Market HHI Values

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

2 "PJM Manual for Scheduling Operations, Manual M-11," page 3-4.
3 FERC, Docket No. ER00-1630, Affidavit of Joseph E. Bowring, February 2000.
4 See Section 2, "Energy Market," for a discussion of the HHI

HHI levels experienced thus far are 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 more than two times larger than the demand for regulation. Figures 5-1a and 5-1b illustrate the demand for regulation relative to the available supply of regulation for the PJM Region as a whole and for the PJM-West Region, respectively.

Figure 5-1a Regulation MW Offered Versus MW Purchased
PJM

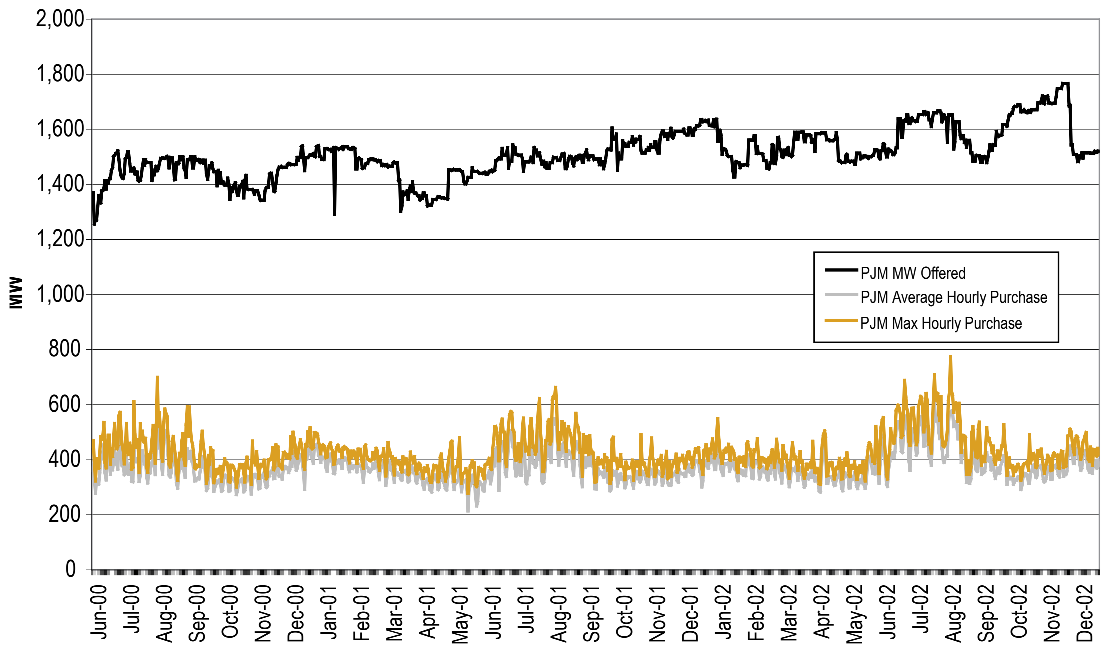
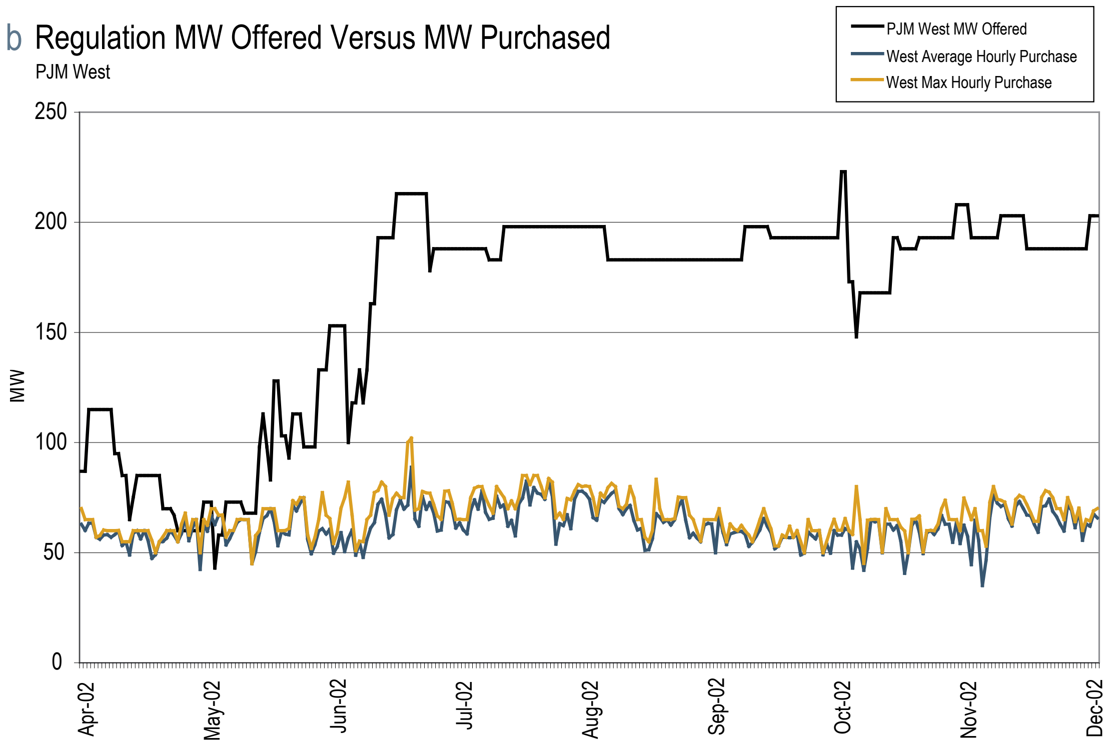


Figure 5-1b Regulation MW Offered Versus MW Purchased
PJM West



Regulation Market Performance

Regulation Offers

Generators wishing to participate in the PJM regulation market must submit price offers for specific units by hour 1800 of the day prior to the operating day. The regulation offer price is subject to a $100 per MWh offer cap and is the only component of the regulation offer that is applicable for the entire operating day. The following information must be included in each regulation market offer but can be entered or changed up to 60 minutes prior to the operating hour: (1) regulating status; (2) regulation capability; and (3) high and low regulation limits.

The spinning and regulation markets are cleared simultaneously and co-optimized in order to reduce the total cost of both ancillary products combined. In contrast to the previous regulation market design, the current regulation market is cleared in real-time instead of day-ahead and regulation prices are posted hourly throughout the operating day. With the current market design, the amount of self-scheduled regulation is confirmed 60 minutes prior to each operating hour and the regulation assignments are made 30 minutes prior to each operating hour.

The regulation market business rules for the PJM-West Region are similar to those for the PJM Region as a whole. The PJM-West Region regulation offers are capped, however, at the marginal cost of providing the regulation service because there is an insufficient number of regulation suppliers in the PJM-West Region to ensure a competitive market. The PJM-West Region's regulating units are compensated at their individual regulation offer plus lost opportunity cost rather than at a single market-clearing price.

Regulation Prices

As Figures 5-2a and 5-2b show, despite several significant, short-lived spikes in the cost of regulation most notably in the summer of 1999, in May 2000, in August 2001, and during the periods of high load in the summer of 2002, 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 locational marginal price (LMP) and the regulation cost. Price spikes occur in the regulation market as the result of supply and demand fundamentals.

Figure 5-2a Hourly Regulation Cost Per MW
PJM

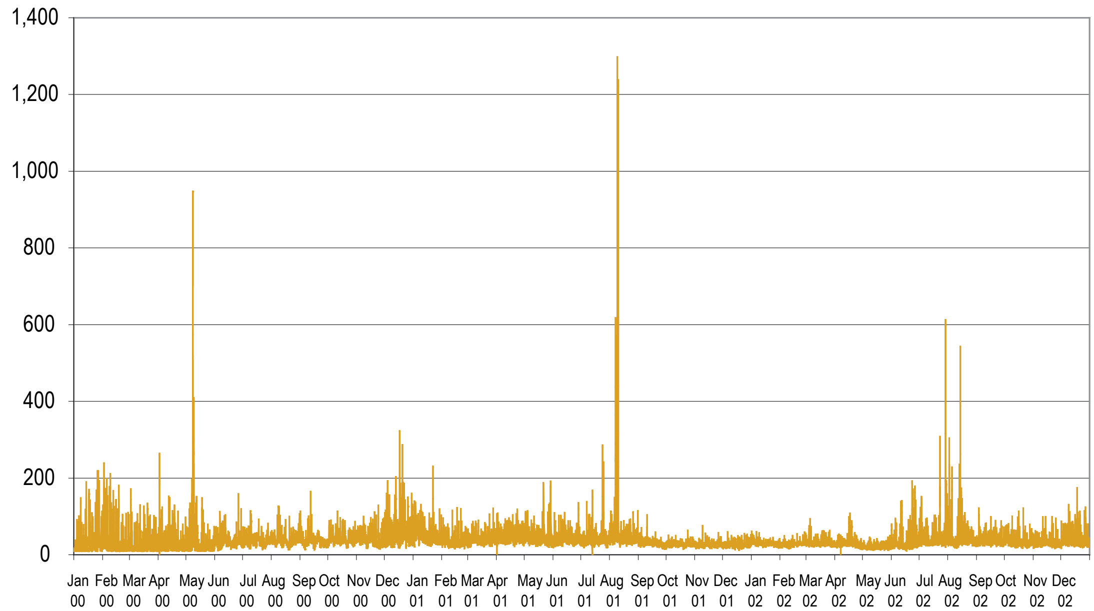
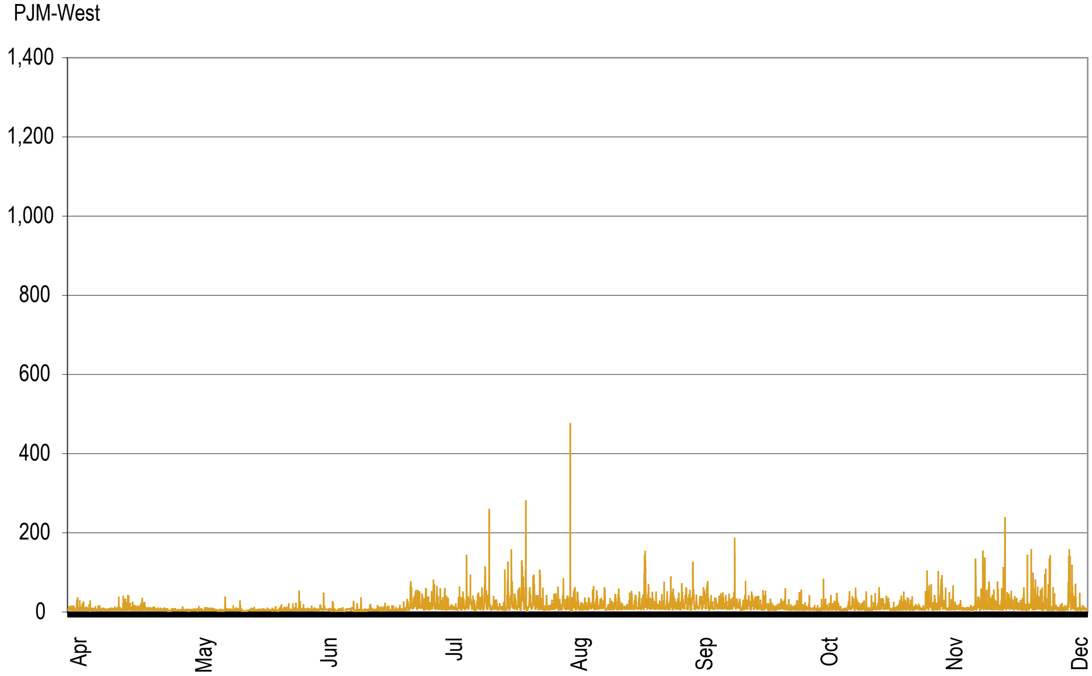


Figure 5-2b Hourly Regulation Cost Per MW



Figures 5-3a and 5-3b compare the regulation cost per MW to the demand for regulation for the period from January 1999 through December 2002. Since the introduction of a regulation market, the per-unit cost of regulation has spiked when system LMP has spiked. The demand for regulation is a linear function of forecast energy demand. When loads increase, the result is an increase in demand for regulation. In addition, increases in system LMP 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.

Figure 5-3a Daily Regulation MW Purchased Compared to Cost Per Unit
PJM

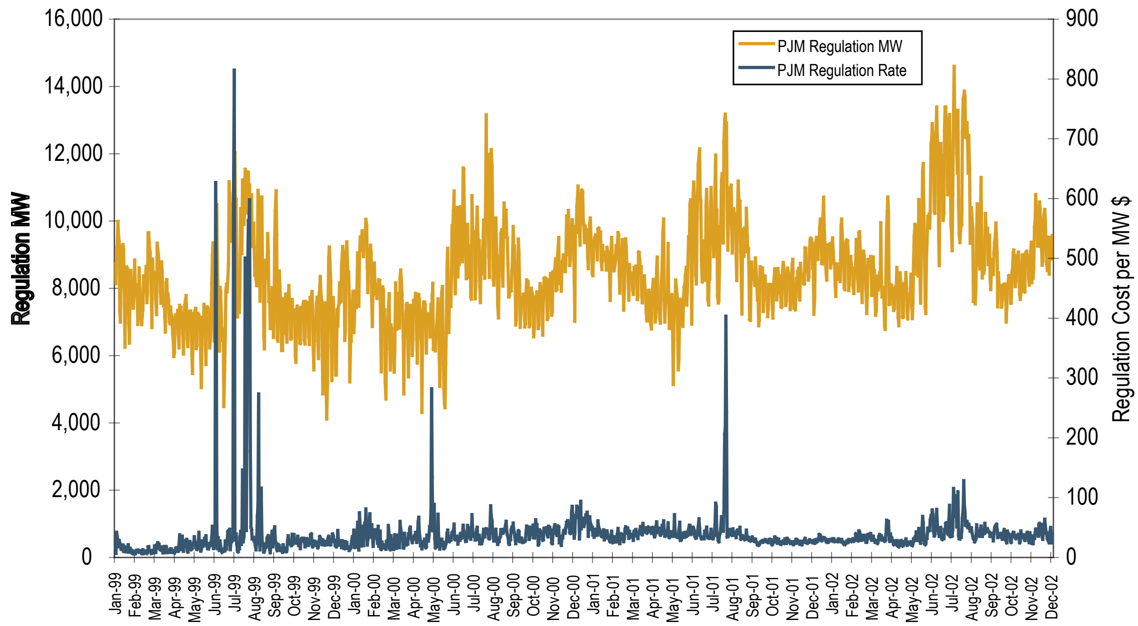
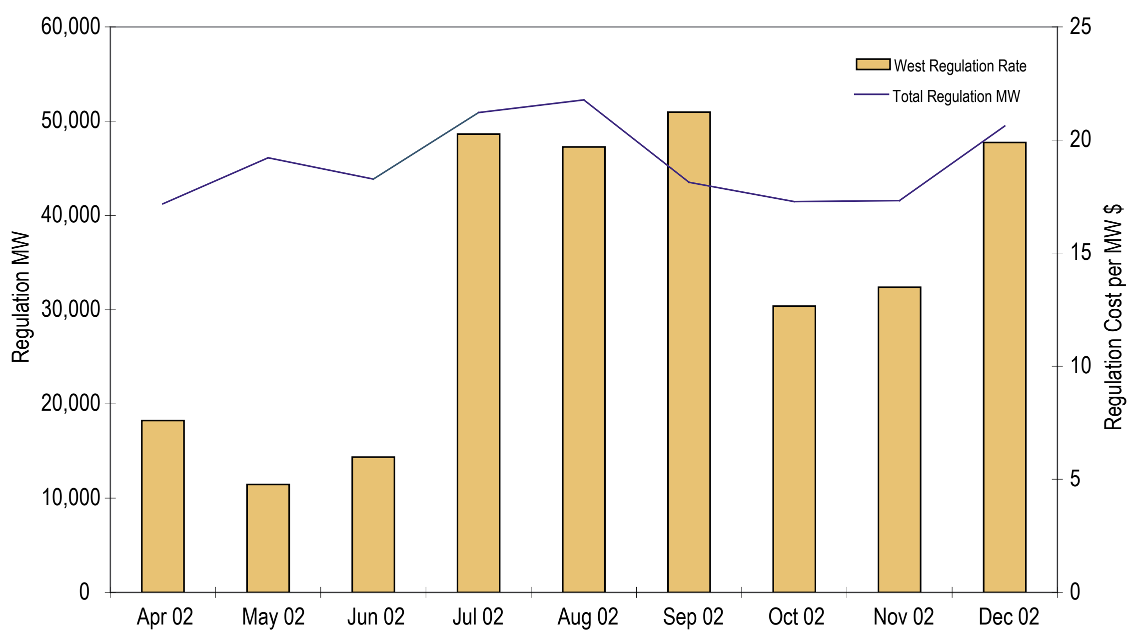


Figure 5-3b Monthly Regulation MW Purchased Compared to Cost Per Unit
PJM-West



Figures 5-3a and 5-3b compare the regulation cost per MW to the demand for regulation for the period from January 1999 through December 2002. Since the introduction of a regulation market, the per-unit cost of regulation has spiked when system LMP has spiked. The demand for regulation is a linear function of forecast energy demand. When loads increase, the result is an increase in demand for regulation. In addition, increases in system LMP 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.

Figure 5-4 Daily Regulation Cost Per MW
1999 - 2002 (Includes PJM-West)

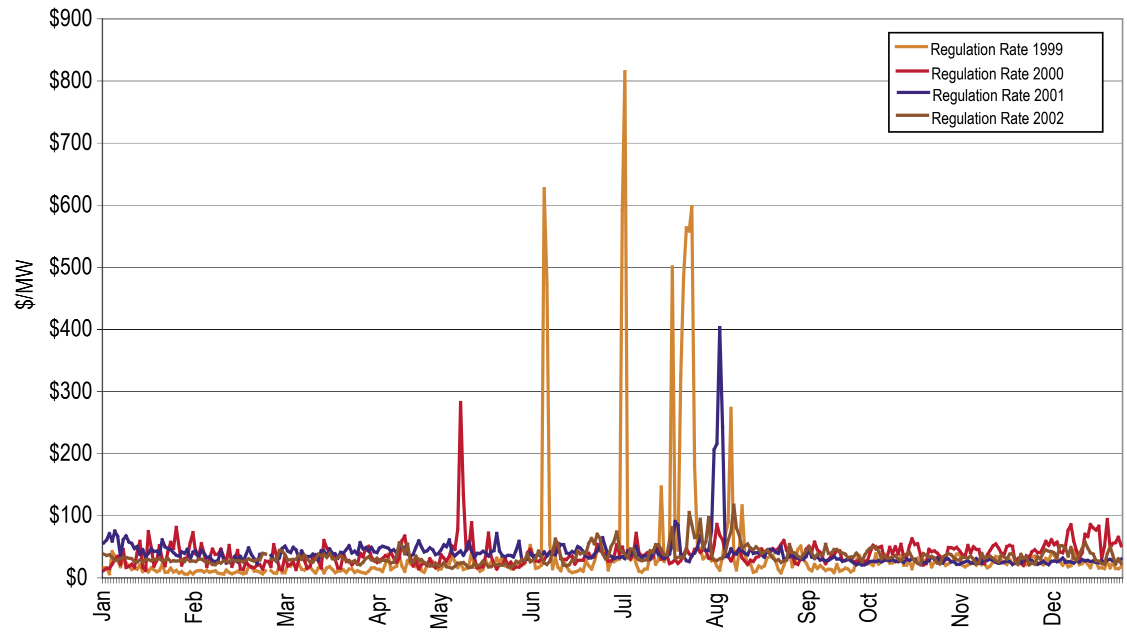


Figure 5-4 compares the average daily cost per MW of regulation for 1999, 2000, 2001, and 2002 (Figure 5-4 includes both the PJM-East and PJM-West Regions). The cost per MW of regulation for the PJM Region was 1.8 percent lower in 2002 than in 2001 and 0.2 percent lower than in 2000. The cost per MW of regulation in 2002 was also 5.4 percent lower than in 1999, the last full calendar year under a cost-based regime.

The data presented in Figures 5-2a, 5-2b and 5-4 show that the market-based, average per-unit price of regulation is consistent with 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.

The data presented in Figures 5-3a and 5-3b 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 the regulation market was competitive in 2002.

The close relationship between the regulation market and the energy market is essential for the efficient and competitive provision of both energy and regulation. This close relationship, however, also creates the potential for market issues in the energy market to be transferred to the regulation market. For example, 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 2002, the potential for issues requires ongoing scrutiny.

Regulation Effectiveness

Under both 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 shortfall could have resulted from the fact that the administrative payments for regulation were based on the difference between the current hourly LMP and a fixed regulation cost based on an historical average energy cost calculation. The result, during some off-peak hours, was that there might have been little incentive to provide regulation. 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 5-5 shows that during the first five months of 2000, the supply of regulation was consistently less than the target level of regulation. After 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 percent in the first five months of 2000 to about 89 percent in the months after 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.[5] While the improved availability of regulation illustrated in Figure 5-5 is important, the ultimate success of regulation in balancing load and generation is not directly measured by regulation performance but is measured by PJM's compliance with North American Electric Reliability Council (NERC) Control Performance Standards CPS1 and CPS2.[6]

Figure 5-5 Percent of Hours Within Required PJM Regulation Limits

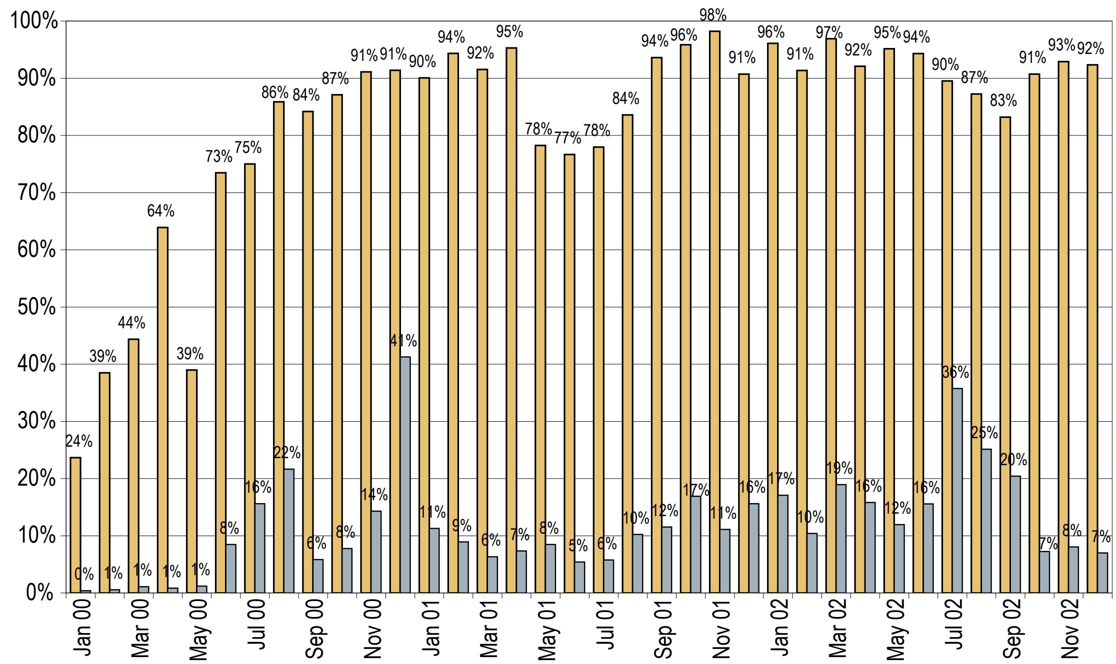
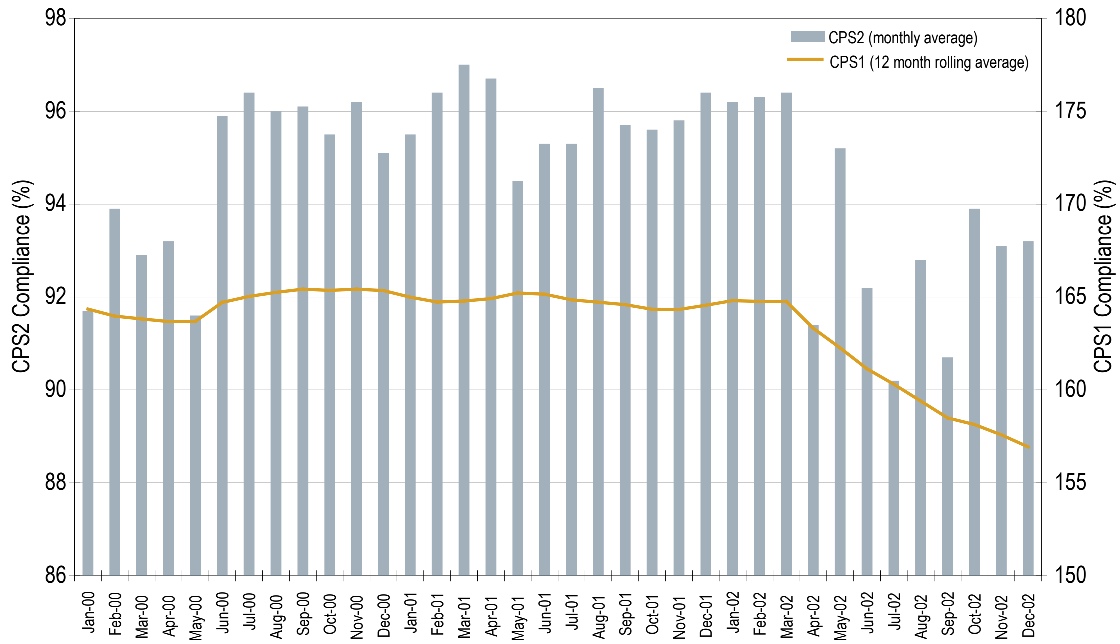


Figure 5-6 shows PJM's regulation performance as measured by the NERC Control Performance Standards CPS1 and CPS2. These standards measure the relationship between generation and load. CPS1 is measured on a 12-month rolling average and provides what NERC terms a "frequency-sensitive evaluation" of how a control area meets its demand requirements. CPS2 measures the balance between load and generation on a 10-minute basis. Figure 5-6 shows that, as measured by CPS1, performance has, on average, improved since the introduction of the regulation market; as measured by CPS2, performance has declined by 0.3 percent. Both CPS1 and CPS2 performance have declined, however, since the introduction of the PJM-West Region.

5 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."

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

Figure 5-6 CPS1 and CPS2 Performance



The data presented in Figures 5-5 and 5-6 illustrate the improvement in regulation performance that 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 new regulation market has been in place for only one month; that the PJM-West Region has been part of PJM for only nine 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

Spinning Offers

PJM introduced a market in spinning reserves on December 1, 2002. Prior to the spinning market, Tier 1 spinning reserves had not been compensated and Tier 2 spinning reserves had been compensated on a unit-specific, cost-based formula.

Under the new rules, several steps are necessary before the spinning market is cleared for an hour. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserves that are available from every unit and 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. If spinning requirements are not met by Tier 1 and self-scheduled Tier 2, then a Tier 2 clearing price is determined 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit order price of the highest cost Tier 2 resource that is needed to fulfill the spinning requirements. A unit's merit order price is a combination of the estimated unit opportunity cost per MWh of capability, the energy use per MWh of capability, and the unit's spinning offer price. The energy use is calculated as the forecast LMP multiplied by the ratio of MW of energy use over spinning capability.

The spinning offer price submitted for a unit can be no greater than the maximum value of the unit's operating and maintenance cost plus a $7.50 per MWh margin.[7] All units cleared in the spinning market are paid the market-clearing price established by the marginal unit. The Tier 2 spinning market is a cost-based market based on the MMU analysis demonstrating that there were insufficient competitors to ensure a competitive outcome. This concern is exacerbated by the fact that the number of competitors can be further significantly reduced when the spinning market becomes local due to transmission constraints.

The PJM-West Region operates under the same business rules as those of the PJM Region, with key exceptions based on competitive concerns. The Spinning Reserve Market in the PJM-West Region is cost-based rather than market-based because of the inadequate number of suppliers in the PJM-West Region. The spinning offers of PJM-West Region generators must reflect the marginal cost of providing spinning reserve from these generators. Generators that provide spinning reserves are compensated by the combination of their spinning offer price, the actual lost opportunity cost, and the energy use incurred providing the spinning reserve and not based on a market-clearing price.[8] During December 2002, a minimal amount of spinning was purchased in the PJM-West Region.

Market Structure

Spinning reserve is an ancillary service defined to be generation which is synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can, at present, be provided by a number of sources, including steam units with available ramp, condensing hydroelectric units, condensing Combustion Turbines (CTs), CTs running at minimum generation and steam units scheduled a day ahead to provide spinning.

All of the units that participate in the spinning market are categorized as either Tier 1 or Tier 2 spinning. Tier 1 resources are those units that are on line, following economic dispatch and able to respond to a spinning event by ramping up from their present output. All units operating on the PJM system are considered Tier 1 resources, except for those explicitly assigned to Tier 2 spinning. Tier 2 resources include units that are backed down to provide spinning capability and condensing units synchronized to the system and available to increase output.

Figure 5-7 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 Tier 1 units. What is now termed Tier 1 spinning was not compensated explicitly under prior market rules. The new spinning market rules allow such units to be compensated if they respond to a spinning event.

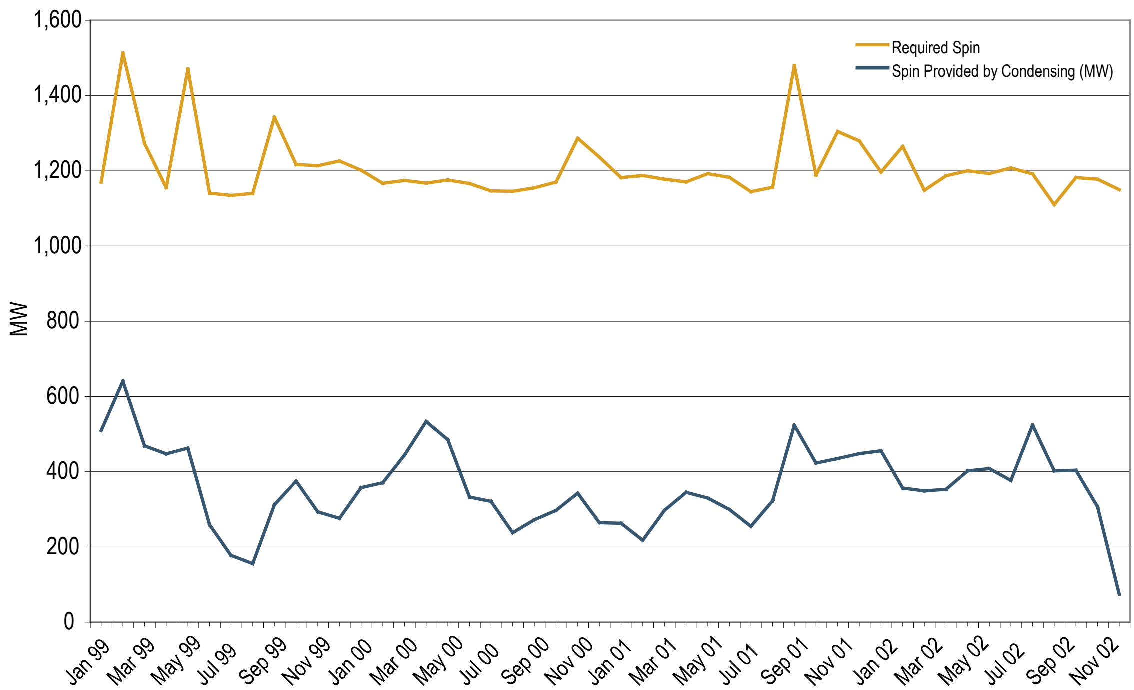
7 "PJM Spinning Reserve Market Business Rules," November 13, 2002.

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

The PJM spinning requirement consists of 75 percent of the largest contingency on the PJM system provided that 50 percent of the largest contingency is available as non-synchronized, 10-minute reserves.[9] Figure 5-8 shows the annual average hourly condensing MW purchased by PJM since 1998. The total level of required spinning reserves ranged from about 1,100 MW to 1,500 MW from 1999 to 2002 and averaged about 1,200 MW (Figure 5-7).

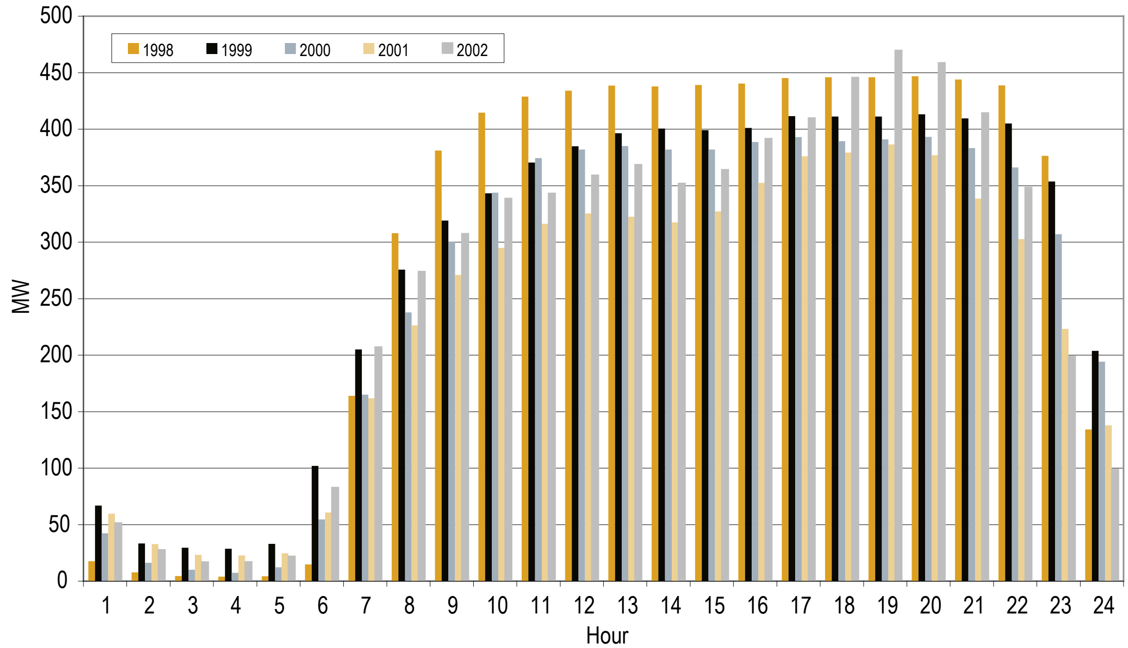
Concentration is high in the Tier 2 spinning reserve market. Average HHI in December was in excess of 2500.

Figure 5-7 Required Spin Provided by Condensing



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

Figure 5-8 Average Hourly Condensing MW



Spinning Prices

The average cost per MW associated with meeting PJM's demand for spinning reserves increased about five percent in 2002 over 2001. Figure 5-9 shows the increase from an average price of about $19 per MW in 2001 to about $20 per MW in 2002. The introduction of the new market in December, however, brought a decrease from about $23 per MW in November to $20 per MW in December.

Figure 5-9 Total Condensing Credits Per MW

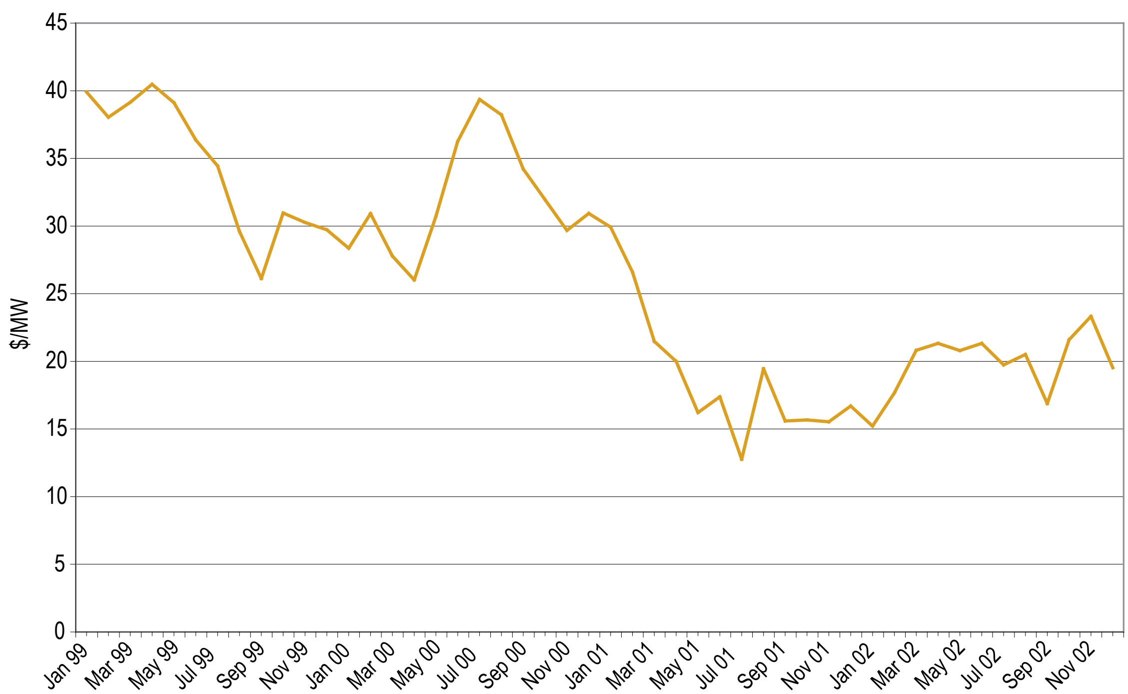


Figure 5-10 December 2002 Spinning Payments: Tier 1 and Tier 2

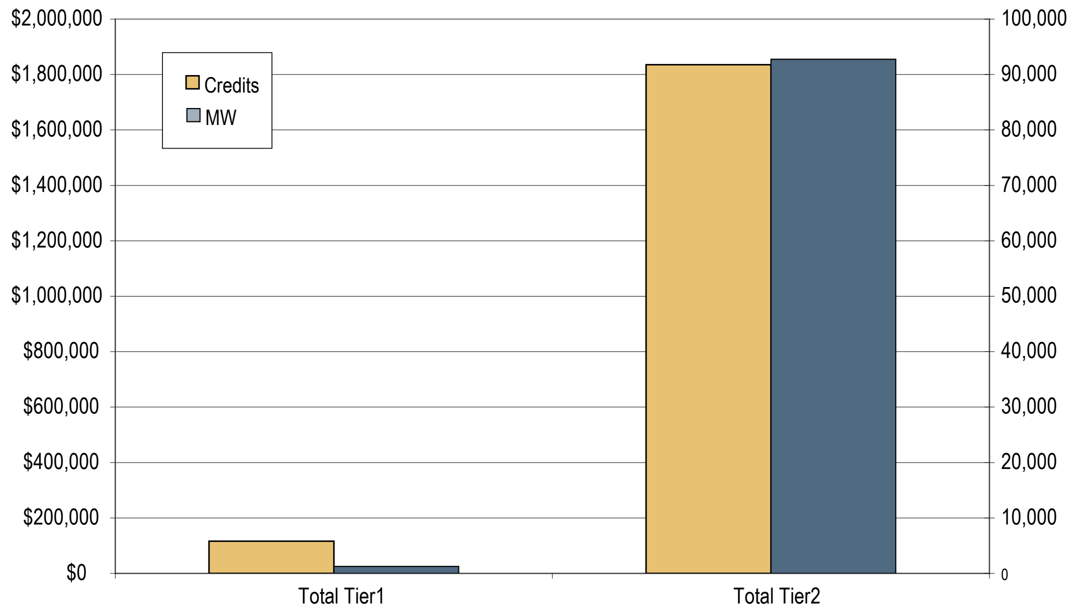


Figure 5-10 shows the level of Tier 1 and Tier 2 spinning reserves explicitly purchased from suppliers in the new market in December. Tier 1 resources are paid only if they respond during spinning events. This balance can be expected to change as more spinning events are called and Tier 1 resources are called upon to spin.

SECTION 6—CONGESTION

Congestion occurs when available, low-cost energy cannot be delivered to all loads as a result of limited transmission facilities. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in that area must be dispatched to meet the load.[1] The result is that the price of energy in the constrained area is higher than elsewhere and congestion exists. Locational Marginal Prices (LMPs) reflect the cost of the lowest cost resources available to meet loads, taking into account the actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way of pricing energy supply when transmission constraints exist. Congestion reflects this efficient pricing.

OVERVIEW

- **Total Congestion Costs.** Congestion costs were approximately $430 million in 2002, a 58 percent increase from $271 million in 2001. This increase in measured congestion was, in significant part, the result of adding PJM-West facilities to the market, permitting the more efficient redispatch of local generation and making explicit the price differentials that result from that redispatch. The increase in congestion costs was one part of a mosaic of impacts associated with the addition of PJM-West. Inclusion of PJM- West generation facilities in the market and the use of locational pricing to target redispatch to the appropriate constrained transmission facilities simultaneously contributed to lower overall average PJM prices, reductions in LMP differentials in some zones and increases in LMP differentials in other zones.
- **PJM-West Region Facilities.** Most of the measured aggregate congestion cost increase is attributable to the redispatch of generating units to control constraints on PJM-West Region transmission facilities. The inclusion of these facilities in the PJM market did not change the underlying physical transfer capabilities of the transmission system. The physical limitations on the ability of the transmission system to transfer lower cost western power to the PJM-East Region existed prior to the addition of the PJM-West Region. However, the inclusion of the PJM-West Region constrained facilities in the market did mean that these transmission system limitations were priced explicitly and efficiently in 2002 and were thus defined as congestion in an LMP-based system.
- **Congestion Geography.** The addition of PJM-West Region transmission facilities to the market resulted in the redispatch of those PJM units required to relieve congestion on specific transmission constraints rather than the simple restriction of all power transfers that had been the pre-market method of controlling congestion for transfers of power from west to east across the Allegheny Power System (APS) and across PJM. The result of this market-based redispatch was the explicit pricing of congestion via LMP which in turn produced a decrease in LMP differentials for some PJM transmission zones and an increase in LMP differentials for other PJM zones after April 1, 2002.
- **Congested Facilities.** Both interface and transformer facilities experienced increases in congested hours during 2002, while congested hours on lines decreased. There were increases in constrained hours on 500kV, 345 kV, 138 kV and 115kV lines and decreases in constrained hours on 230 kV and 69 kV lines.

1 This is referred to as dispatching units out of merit order. Merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean that the next unit in merit order cannot be used and that a higher cost unit must be used in its place.

- **Monthly Congestion Charges.** Monthly swings in congestion continue to be substantial. In 2002, these swings were driven by different patterns of generation, energy imports, weather-induced demand spikes and increased congestion frequency on constraints affecting large portions of PJM load.
- **Local congestion.** Local congestion in the DPL zone decreased as the result of ongoing transmission reinforcement projects and rose in other zones, including PENELEC.

Increases in congestion resulting from the addition of PJM-West and the persistent congestion that exists in areas within PJM suggest the importance of PJM continuing to develop the sophistication of its congestion analysis and, based on that analysis, implementing the Order issued by the United States Federal Energy Regulatory Commission (FERC) 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.

On July 12, 2001, FERC had issued an Order granting PJM provisional status as a Regional Transmission Organization (RTO).[2] In it, 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."

FERC's December 19, 2002, "Order Granting RTO Status" further stated:

> "We find that PJM's September 10 compliance filing does not meet our directive that the PJM planning process identify expansions that are needed to support competition as well as reliability needs. In its compliance filing, PJM states that additional time is needed for PJM's Planning Committee to develop specific criteria. In order to fully meet the planning and expansion function for an RTO, we will require PJM to make a further compliance filing within 90 days that more fully explains how PJM's planning process will identify expansions that are needed to support competition. PJM's regional transmission plan must provide authority for PJM to require upgrades both to ensure system reliability and to support competition. Thus, we anticipate that the plan will enable PJM to (a) require the necessary additions to its TOs' systems to ensure reliability, and (b) identify transmission constraints and require new construction to address those constraints. "

CONGESTION ACCOUNTING

Transmission congestion can exist in both the day-ahead and the balancing markets, and total congestion is the sum of the two. Transmission congestion in the day-ahead market can be directly hedged by using Fixed Transmission Rights (FTRs). Real-time congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the day-ahead market.

2 96 FERC ¶ 61,061 (2001).

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

Total Congestion Cost

Table 6-1 shows total congestion by year from 1999 through 2002. The $430 million of congestion charges during 2002 was 58 percent higher than the $271 million incurred during 2001. Congestion costs were nearly equal in the first half of 2001 and 2002; the increase occurred in the second half of 2002.

This increase in measured congestion was, in significant part, the result of adding PJM-West facilities to the market, permitting the more efficient redispatch of local generation and making explicit the price differentials that result from that redispatch. The increase in congestion costs was one part of a mosaic of impacts associated with the addition of PJM-West. Inclusion of PJM-West generation facilities in the market and the use of locational pricing to target redispatch to the appropriate constrained transmission facilities simultaneously contributed to lower overall average PJM prices, reductions in LMP differentials in some zones and increases in LMP differentials in other zones.

Congestion at PJM's Bedington-Black Oak and APS South Interfaces (both interfaces between PJM-West and PJM-East Regions), at Doubs 500/138 and at the Wylie Ridge and Kammer transformers contributed significantly to overall congestion. The two interfaces each affect prices for about 25 percent of PJM load, Doubs affects prices for about 10 percent of PJM load while the transformers affect prices for about 95 percent of PJM load.

Table 6-1 --Total Congestion

Year	$ in Millions	% Increase
2002	$430	58%
2001	$271	105%
2000	$132	149%
1999	$53	N/A

Table 6-2, the "2002 PJM Congestion Accounting Summary," lists congestion charges, FTR target allocations and credits, payout ratios, congestion credit deficiencies, and excess congestion charges by month. 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 some months had congestion credit deficiencies, after the year-end distribution of excess congestion charges, FTRs were paid at 95 percent of the target allocation level. The fact that in the aggregate FTRs provided a hedge against 95 percent of the target allocation level 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 6-2— 2002 PJM Congestion Accounting Summary ($ in millions)

Period	Congestion Charges	FTR Target Allocations	Congestion Credits	FTR Payout Ratio	Congestion Credit Deficiency	Excess Congestion Charges
Jan-02	$10	$11	$10	91%	$1.0	$0.0
Feb-02	$5	$5	$5	99%	$0.0	$0.0
Mar-02	$6	$5	$5	100%	$0.0	$1.0
Apr-02	$21	$22	$21	95%	$1.0	$0.0
May-02	$18	$20	$18	90%	$2.0	$0.0
Jun-02	$29	$29	$29	100%	$0.0	$0.2
Jul-02	$64	$66	$64	98%	$1.5	$0.0
Aug-02	$104	$97	$97	100%	$0.0	$7.0
Sep-02	$16	$21	$17	80%	$4.2	$0.0
Oct-02	$47	$48	$47	97%	$1.4	$0.0
Nov-02	$50	$56	$50	89%	$6.4	$0.0
Dec-02	$59	$71	$60	84%	$11.1	$0.0
Total	$430	$452	$423	94%	$29	$8.2
Final 2002 Values After Distribution of Excess Congestion Charges						
Total	$430	$452	$430	95%	$22	$0

Monthly Congestion Charges

Table 6-3 shows congestion charge variations by month, day and hour. During 2002, monthly congestion charges ranged from a maximum of $104.3 million in August to a minimum of $5.2 million in February. Mean monthly congestion charges were $36 million, compared to the $23 million mean of 2001.

Table 6-3—2002 Transmission Congestion Revenue Statistics ($ in millions)

Period	Maximum	Mean	Median	Minimum	Range
Monthly	$104.3	$35.8	$24.8	$5.2	$99.1
Daily	$10.8	$1.2	$0.6	($1.3)	$12.1
Hourly	$2.6	$0.05	$0.01	($2.1)	$4.7

During 2002, the difference between the monthly minimum and maximum congestion (Range) increased to $99.1 million from $66.2 million in 2001, although the minimum occurred prior to the addition of PJM-West while the maximum occurred after the addition. In addition, the difference between the daily minimum and maximum decreased, from $40.4 million to $12.1 million and the difference between the hourly minimum and maximum congestion revenues decreased from $7.1 million to $4.7 million.

Approximately 40 percent of all congestion occurred during the two peak-demand months of July and August; approximately one-half of the $158 million increase in congestion can be attributed to these two months. This pattern was similar to that of 2001 when 34 percent of congestion cost was incurred during those same summer months.

The majority of monthly congestion charges often accrue during just a few days. For example, during August, the five most congested days accounted for 44 percent of monthly congestion charges. Similarly, in July and December, the months with the second and third highest congestion charges, five days accounted for 47 percent and 33 percent, respectively, of each month's congestion charges.

In 2002, the maximum monthly congestion, $104.3 million, occurred in August. During the on-peak hours of just five days in August, 43 percent of monthly congestion charges were accrued. The Bedington-Black Oak Interface and Kammer 765/500 transformer were constrained during 44 percent and 39 percent of those hours, respectively. Kammer restricts power transfers to essentially the entire PJM Region at the PJM/AEP interface, while Bedington-Black Oak limits transfers into the southwestern part of the PJM-East Region.

The maximum value of daily congestion, $10.8 million, occurred on August 5th, a day when demand was high. Again it was the Bedington-Black Oak and Kammer 765/500 constraints that were largely responsible for the high level of congestion. August 5th also accounted for three of the top 10 congestion hours, each with about $1.2 million of congestion.

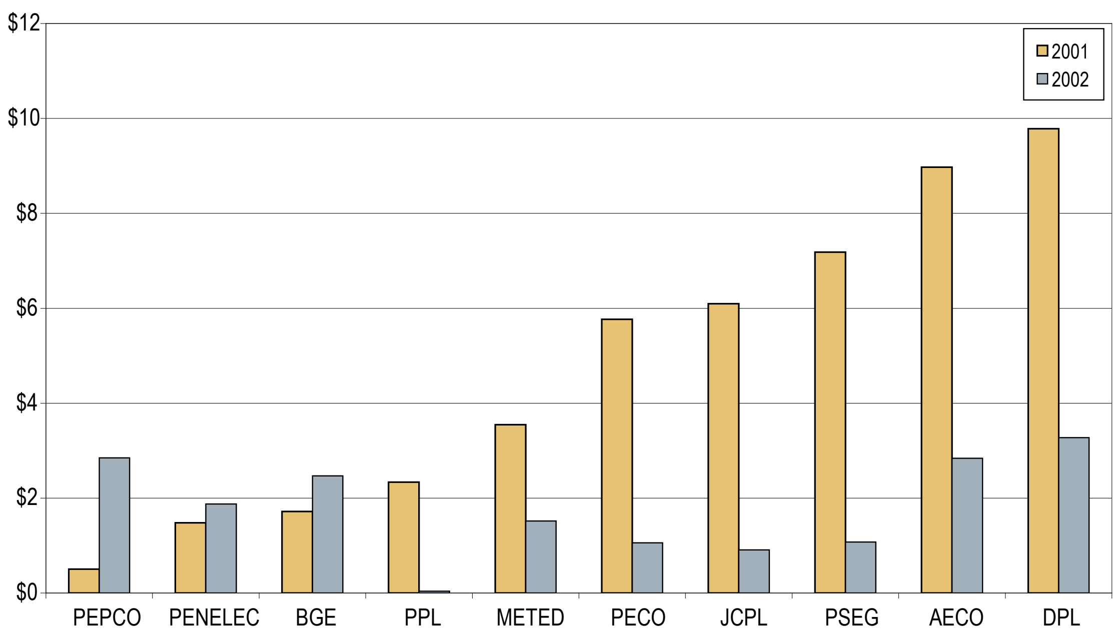
Maximum hourly congestion occurred on the PJM record-setting, peak-demand day, August 14th, when at 1500 hours $2.6 million in congestion charges were accrued. Once again Kammer 765/500 was constrained, as were APS South and West 500/VP interfaces and Doubs 500/230.

Congestion Geography

LMP differentials were calculated for each PJM-East zone to provide an approximate indication of the geographic dispersion of congestion costs. These LMP differentials, presented in Figure 6-1 for both 2001 and 2002, were calculated as the difference between zonal LMP and the Western Hub LMP. The Western Hub was chosen as the unconstrained reference price as it reasonably represents the unconstrained price of energy in the PJM-East Region.

Figure 6-1 shows that during 2002, PEPCO and BGE, neighboring zones located in the southern part of PJM, were two of three zones (PENELEC had significant local congestion) that had year to year increases in the LMP differential and had among the highest 2002 LMP differentials by this measure. Seven of ten PJM-East Region zones experienced significant reductions in LMP differentials between 2001 and 2002. Both the increases and decreases in year to year LMP differentials were, in part, the result of the use of targeted redispatch of units required to solve specific constraints between the PJM-West Region and the PJM-East Region, in place of the pre-market curtailment method of constraint control. Most of the PEPCO and BGE zones' LMP differentials can be attributed to redispatch for the APS Interface constraints (BGE had some limited internal constraints), while the remaining zones, except PENELEC, all experienced LMP impacts in 2002 due in part to redispatch for the West Interface. DPL, AECO, PENELEC and METED experienced congestion in 2002 resulting from constraints internal to their zones as can be seen in Figure 6-3 and subsequent figures presenting details of zonal constraints. DPL, PSEG, JCPL, PECO and AECO also had lower 2002 LMP differentials attributable, in part, to redispatch for the Eastern Interface.

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



CONGESTED FACILITIES

In 2002, there were 11,307 congestion-event hours, a 34 percent increase from the 8,227 in 2001, and a 63 percent increase from 2000. A congestion event exists when units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. Constraints are often simultaneous, hence a total greater than the number of hours in a year. In 2002, 164 different monitored facilities were constrained, an increase of 17 over 2001.

Table 6-4 lists 2001 and 2002 constraints that affected more than 10 percent of PJM load or were most frequently in effect. It shows changes in constrained hours between the years and percent of PJM load impacted.[3]

Constraints 1 through 8 are the primary operating interfaces and each affects more than 25 percent of PJM load.[4] For this group, the number of constrained hours increased from 769 to 2,517 hours between 2001 and 2002, a 227 percent increase, impacting, on average, 58 percent of PJM load. PJM-West Region facilities, items number 1, 2, 7, and 8, were constrained 2,213 hours in 2002, while the PJM-East Region facilities, items number 3 to 6, were constrained only 304 hours, a 60 percent decrease in frequency.

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

4 Percent of impacted load, as presented in Table 6-4, is an approximation.

Table 6-4—Constraint Duration Summary

No.	Constraint	% PJM Load Impacted	Constrained Hours			% of Annual Hours		
			2001	2002	Change	2001	2002	Change
1	Wylie Ridge 500/345	95%	N/A	846	846	0%	10%	10%
2	Kammer 500/345	95%	N/A	174	174	0%	2%	2%
3	Western Interface	65%	429	161	-268	5%	2%	-3%
4	West Volt Interface	65%	78	91	13	1%	1%	0%
5	Central Interface	62%	35	1	-34	0%	0%	0%
6	Eastern Interface	50%	227	51	-176	3%	1%	-2%
7	Bedington - Black Oak 500	25%	N/A	1044	1044	0%	12%	12%
8	APS South Interface	25%	N/A	149	149	0%	2%	2%
9	Doubs 500/138	10%	N/A	235	235	0%	3%	3%
10	PL North Interface	2%	0	213	213	0%	2%	2%
11	Monroe 230/69	2%	154	454	300	2%	5%	3%
12	Edison – Meadow Rd 138	2%	188	356	168	2%	4%	2%
13	Keeney AT20 230/138	2%	21	169	148	0%	2%	2%
14	Erie West - Erie South 345	2%	31	166	135	0%	2%	2%
15	Erie West 345/115	2%	520	901	381	6%	10%	4%
16	Jackson 230/115	2%	169	235	66	2%	3%	1%
17	Towanda Interface	1%	0	538	538	0%	6%	6%
18	Laurel – Woodstown 69	1%	150	380	230	2%	4%	2%
19	Cromby – Moser 69	1%	33	338	305	0%	4%	4%
20	Hallwood - Oak Hall 69	1%	502	286	-216	6%	3%	-3%
21	Cheswold AT1 138/69	1%	85	263	178	1%	3%	2%
22	North Meshoppen 230/115	1%	2	221	219	0%	3%	3%
23	Yorkana A 230/115	1%	0	186	186	0%	2%	2%
24	Cedar Interface	1%	5	166	161	0%	2%	2%
25	Cedar - Motts 69	1%	441	537	96	5%	6%	1%

The Wylie and Kammer transformers affect prices for 95 percent of PJM load, while Bedington-Black Oak and APS South Interfaces both affect prices primarily for PEPCO and BGE load. The Eastern Interface impacts the 48 percent of PJM load located in New Jersey, Delaware, Eastern Pennsylvania, and on Maryland's Eastern Shore. The Central Interface also impacts eastern load, along with an additional 12 percent of PJM load in the PPL and METED zones located in Central Pennsylvania. The Western Interface and Western Voltage Interface constraints affect these areas as well as load in the PENELEC, PEPCO, and BGE zones. During 2002, as in previous years, constraint frequency on the main operating interfaces that affect large amounts of PJM load was reduced in the east and increased in the west.

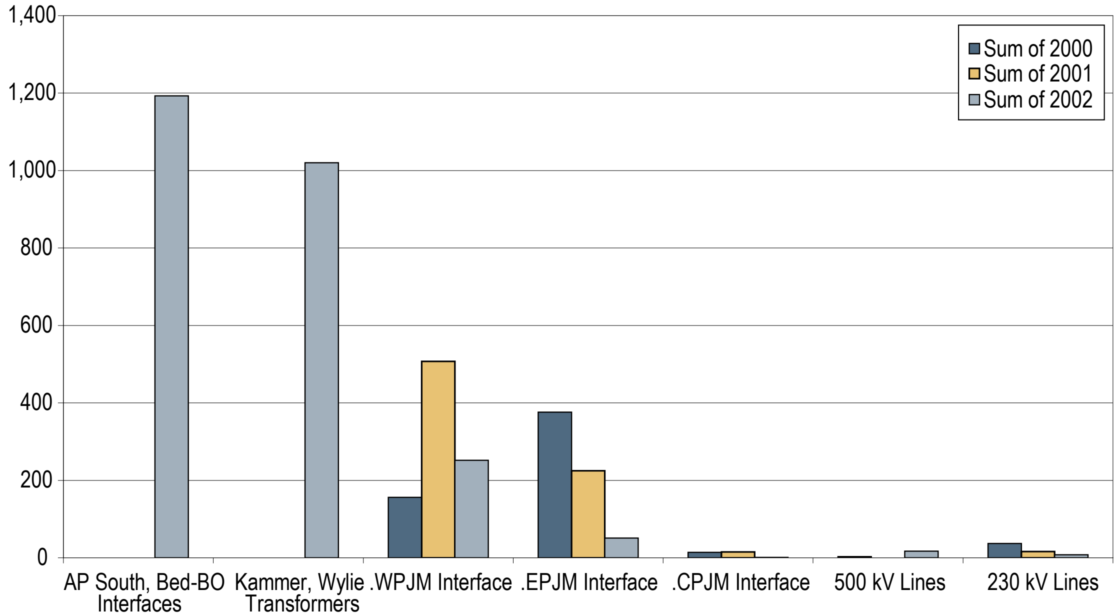
Doubs 500/138, another APS facility, affects approximately 10 percent of PJM load located in the PEPCO, BGE, and APS Zones. The remaining facilities all affect less than two percent of PJM load.

Constraints were examined by zone and categorized by whether they affect regions or subareas. Zones correspond to regulated utility franchise areas, while regions generally comprise two or more zones, and subareas consist of portions of one or more zones. Because constraints on the 500 kV system generally affect multiple zones, these constraints were analyzed separately.

Regional Constraint Hours

Constraints that affected regions during the period 2000 through 2002 are presented in Figure 6-2. Most significant are the 1,200-hour occurrence of the APS Bedington-Black Oak and APS South Interfaces, the 1,000+-hour occurrence of the Kammer and Wylie transformers, and the continued decrease in the occurrence of the Eastern PJM Interface. These constraints affected the PEPCO and BGE zones, essentially all of the PJM, and Eastern PJM, respectively. The figure shows that constraints associated with PJM-West clearly predominate while eastern constraints exhibit substantially smaller frequency of occurrence.

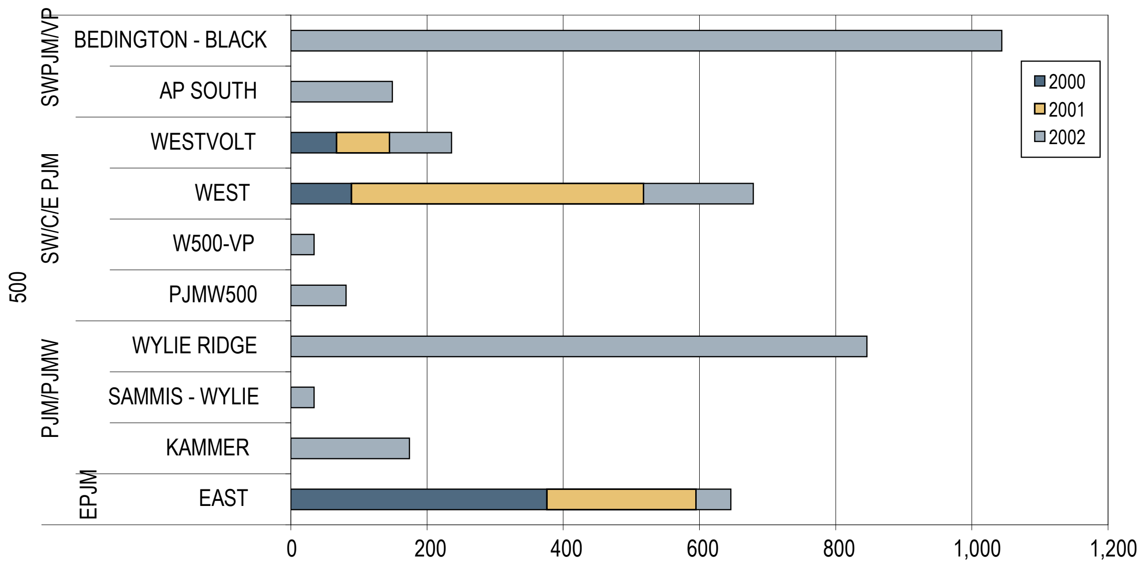
Figure 6-2 Regional Constraints - Congestion-Event Hours by Facility



Regional Constraint Hours for 500 kV System

Constraints on the 500 kV system generally have an impact across wide regions. Figure 6-3 depicts the significant occurrences of 500 kV constraints grouped by affected region. As shown, PJM-West Region constraints were significantly more active in 2002 than were those in the PJM-East Region. The PJM-West Region constraints, Wylie Ridge 500/345, Kammer 765/500, Bedington-Black Oak, and APS South Interfaces were constrained during 2,247 hours compared to 418 hours for major the PJM-East Region constraints.

Figure 6-3 Congestion-Event Hours by Facility --500 kV System



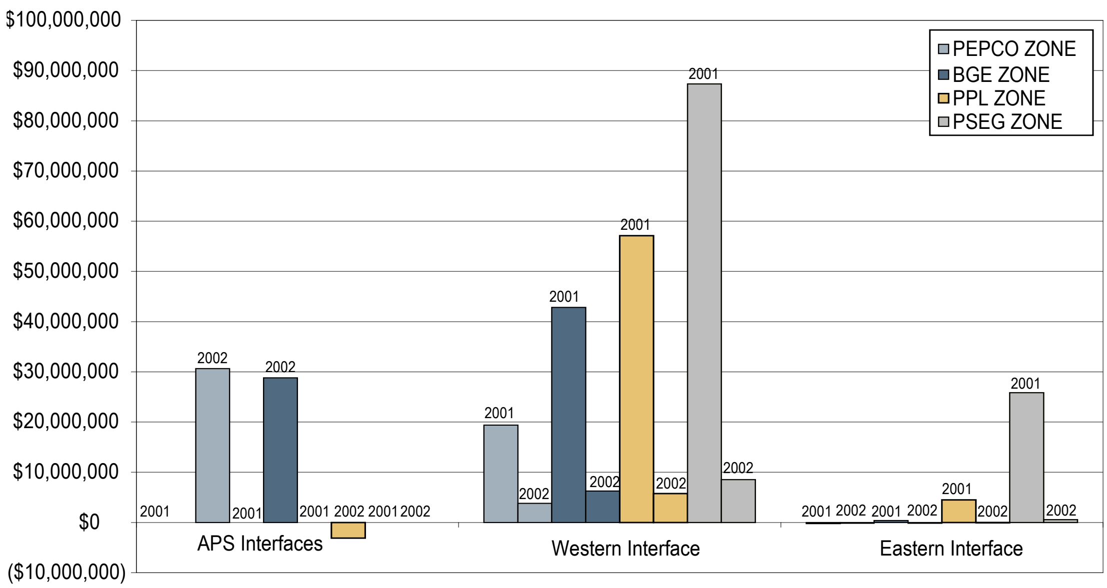
Bedington-Black Oak and APS South Interfaces

The APS extra-high-voltage (EHV) system is the primary conduit for energy transfers from APS and mid-western generating resources to Southwestern PJM and Eastern Virginia load, and to a lesser extent, to Central and Eastern PJM. The two APS reactive interface constraints of interest, Bedington-Black Oak and APS South, often restrict west-to-east energy transfers across the APS EHV system. Prior to the incorporation of APS into PJM on April 1, 2002, the primary controlling action for these constraints had been for APS to restrict energy transfers through its system, transfers from western resources to PJM and VAP. This had the effect of raising the overall PJM dispatch rate higher than it would have been if the transactions had not been curtailed. The result was increased energy prices for the entire PJM-East Region, regardless of location. The result had no impact on measured congestion because the entire PJM system was affected.

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

To quantify the relative congestion cost impacts of such transmission constraints, congestion costs were estimated for the PEPCO, BGE, PPL, and PSEG zones when any of the major, 500 kV interfaces were non-coincidently constrained. The APS South, Bedington-Black Oak and South 500-VP Interfaces were summed into the APS Interfaces group of Figure 6-4, and West, West Volt, and the PJM-West Region 500 Interfaces were summed into the West Interfaces group. East Interface was reported separately.

Figure 6-4 2001-2002 Interface Congestion Noncoincident Constraint Occurrences BGE, PEPCO, PPL, and PSEG Zones



Congestion Costs are estimated as the difference between the constrained and unconstrained energy costs for each zone. Constrained and unconstrained energy costs are the product of each zone's constrained and unconstrained LMPs and corresponding loads.

Estimated total 2002 zonal congestion costs were $34 million and $35 million for PEPCO and BGE Zones, while estimated total 2002 zonal congestion costs were $3 million and $9 million for PPL and PSEG zones. Of these totals, the APS Interfaces accounted for most of the congestion in the PEPCO and BGE zones, $31 million and $29 million, but had no impact on congestion in the PPL and PSEG zones.

In 2001, the West Interfaces had a significant impact on all the zones and a larger impact on the northern zones than the southern zones. In 2001, congestion costs associated with the West Interfaces were $19 million for PEPCO, $43 million for BGE, $57 million for PPL, and $87 million for PSEG zones. In 2002, the West Interfaces had a much smaller impact on all four zones, with the largest reductions for the PPL and PSEG zones.

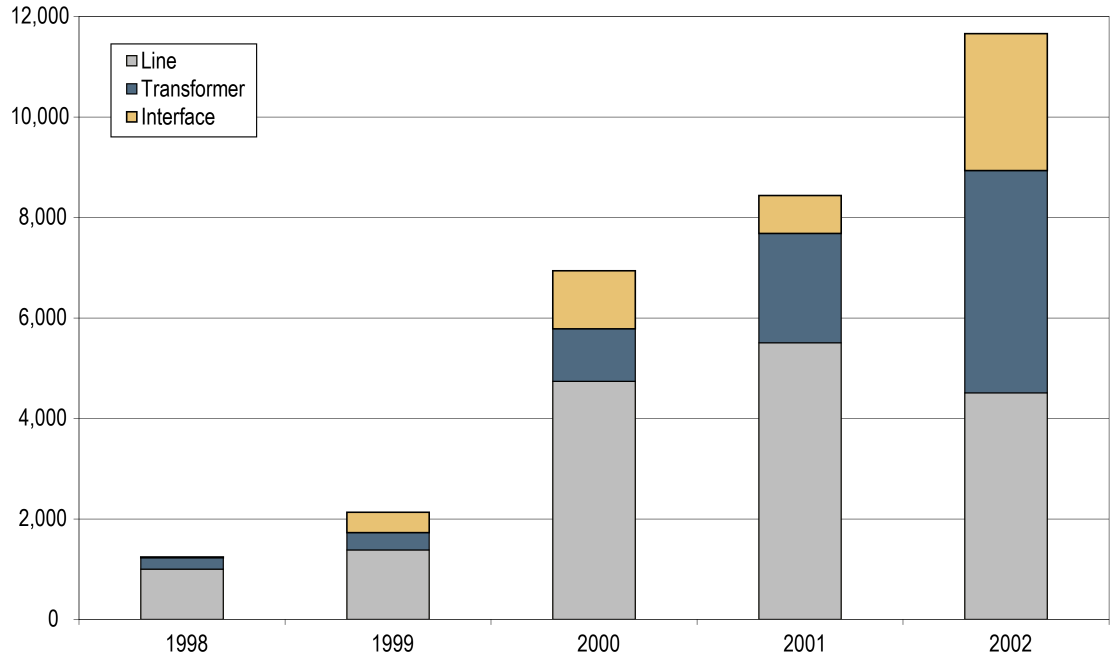
The East Interface affects the PSEG Zone and, to a lesser extent, the PPL zone. In 2001, East-Interface-related congestion costs were approximately $26 million for the PSEG Zone and $4 million for the PPL zone. In 2002, these costs were negligible.

Congestion by Facility Type

Figure 6-5 provides congestion subtotals by facility type: line, transformer, and interface. As shown, constraints on each have increased steadily during each year of the period under analysis, with line constraints leveling off at between 4,500 to 5,500 event-hours per year. Most significantly, the occurrence of reactive interface constraints greatly increased from 950 event-hours on average in 2000 and 2001 to over 2,700 event-hours in 2002. APS constraints alone accounted for over 1,200 event-hours of this increase, and Northern Pennsylvania constraints, Towanda and PPL North, accounted for 1,100 event-hours.

Transformer constraints doubled in 2002, increasing from 2,200 to 4,400 event-hours, with the largest single increase occurring on the Wylie Ridge 765/345 transformer, an APS facility. It began appearing after the incorporation of APS into PJM and appeared an average of 100 hours per month. Also Erie West 345/115 increased in occurrence by nearly 400 event-hours in 2002, while Monroe 230/138 in AECO Zone, Doubs 500/138 in APS Zone, and North Meshoppen 230/115 in PENELEC Zone each had an increase in frequency greater than 200 hours.

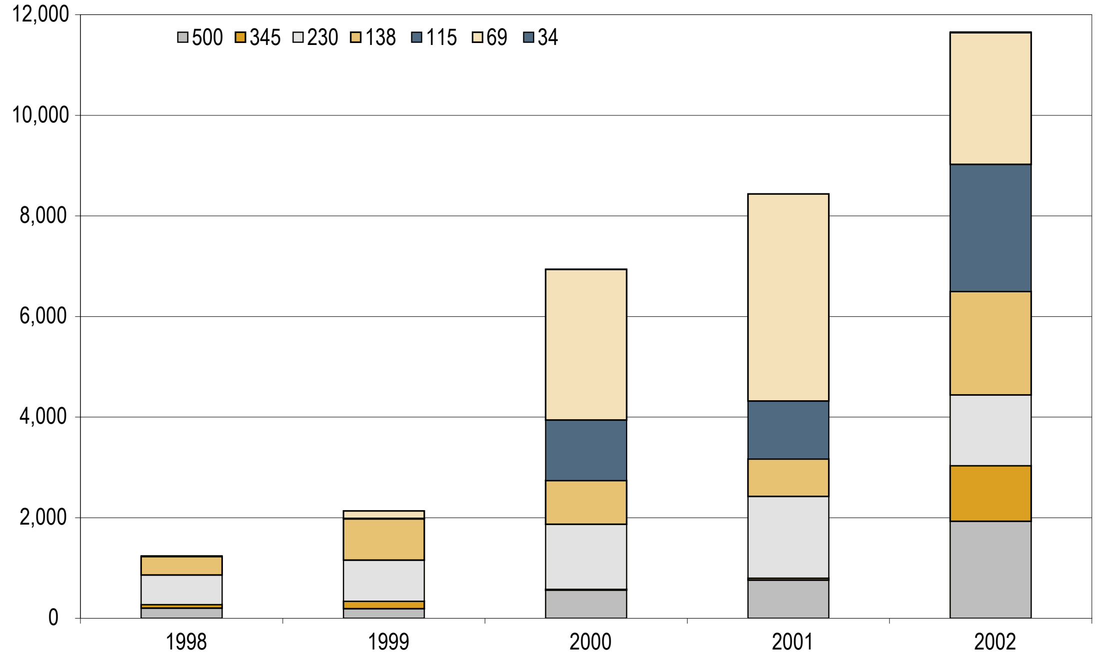
Figure 6-5 Constrained Hours by Facility Type



Transmission line and transformer thermal limits have historically accounted for about 70 percent and 20 percent of all binding constraints, while interface constraints have averaged about 10 percent since the introduction of competitive energy markets in 1998. In 2002, interfaces and transformers increased to 23 and 38 percent of all event-hours.

Figure 6-6 depicts congestion hour subtotals by facility voltage class and shows that constrained hours of operation have generally increased over all voltage classes. There was a notable increase in constraints on facilities with the highest operating voltages, 500 and 345 kV. Most of the increase can be attributed to the incorporation of APS into PJM. There was also an increase in 138 and 115 kV voltage class constraints, with a large portion of the growth directly attributable to APS constraints. DPL transmission system improvements reduced 69 kV constraints by 1,500 event-hours alone. These data indicate an increased occurrence of system constraints that generally affected larger parts of the system.

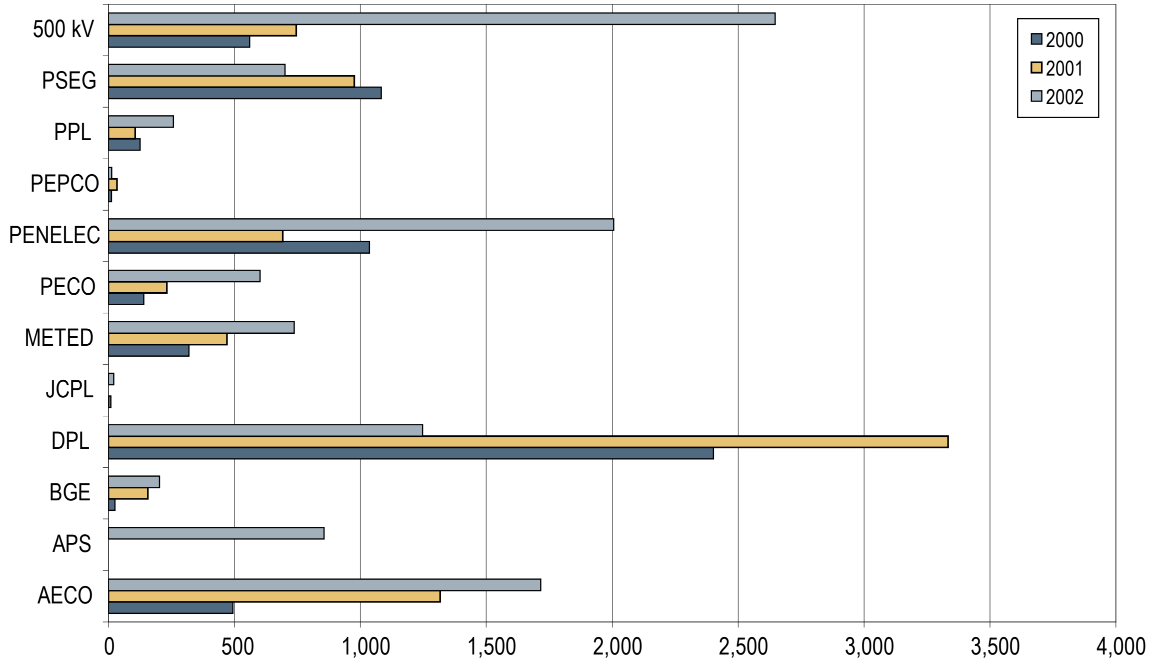
Figure 6-6 Constrained Hours by Facility Voltage



Zonal Constraint Hours

Constraints within specific zones from 2000 through 2002 are presented in Figure 6-7, which shows the comparative number of constraints that occurred in each zone and on the 500 kV system. PENELEC, DPL, and AECO Zones and the 500 kV system all had over 1,000 congestion-event hours in 2002, with constraints on the 500 kV system having increased most notably. Nearly all of the increase in constrained operation on the 500 kV system was attributable to constraints on PJM-West facilities. The Erie West 345/115 transformer and the Towanda interface accounted for the bulk of the 2002 increase in PENELEC Zone, while Monroe 230/138, Laurel-Woodstown 69, and Cedar Interface accounted for the increase in the AECO Zone. DPL Zone showed a large decrease in constrained hours of operation that can be attributed to completion of transmission reinforcements.

Figure 6-7 Constrained Hours by Zone



Zonal and Subarea Constraint Hours

Figures 6-8 through 6-16 illustrate constraints by franchise area zones and subareas. These constraints generally impact energy prices only within the affected zone.

Figure 6-8 illustrates the AECO Zone constraints. In particular, a very small subarea consisting of just two 69 kV substations, Motts Farm and Cedar, called the Cedars subarea, continued to be frequently constrained, increasing to nine percent of all hours in 2002. Also significant were the Monroe 230/138 transformer and Laurel-Woodstown 69 in Southern New Jersey (SNJ), which were constrained five percent and four percent of all 2002 hours, respectively. Monroe impacts approximately 50 percent of AECO Zone load and less than two percent of PJM load, while Laurel-Woodstown affects only a small area consisting of two 69 kV substations.

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

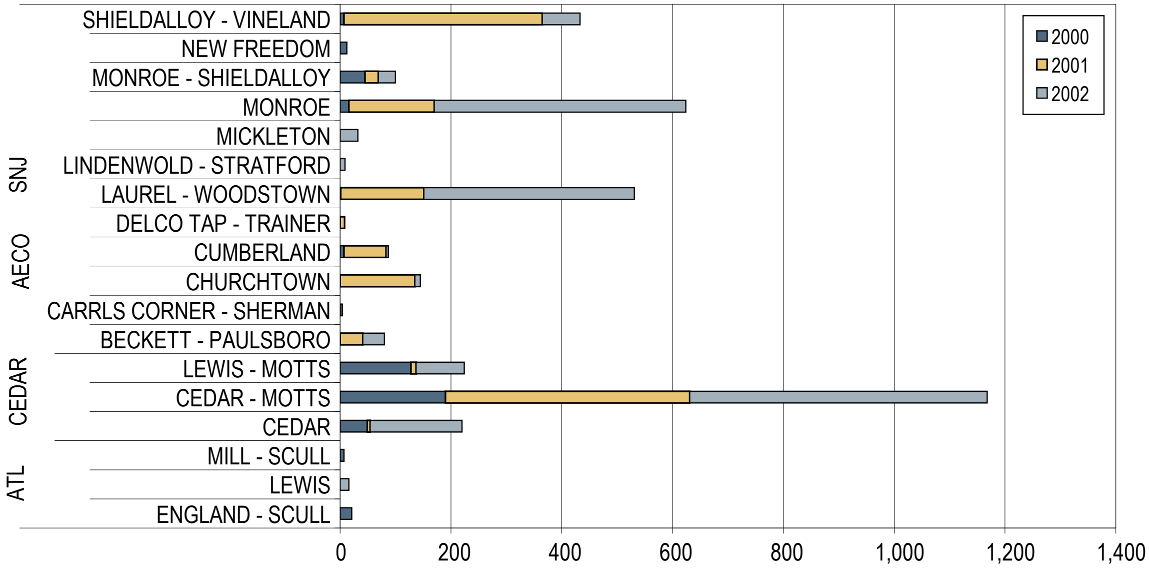


Figure 6-9 illustrates the APS Zone constraints. Doubs 500/230, which affects approximately 15 percent of PEPCO and APS Zone load, is the most significant of these since the rest only affect small load pockets, with none frequently constrained.

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

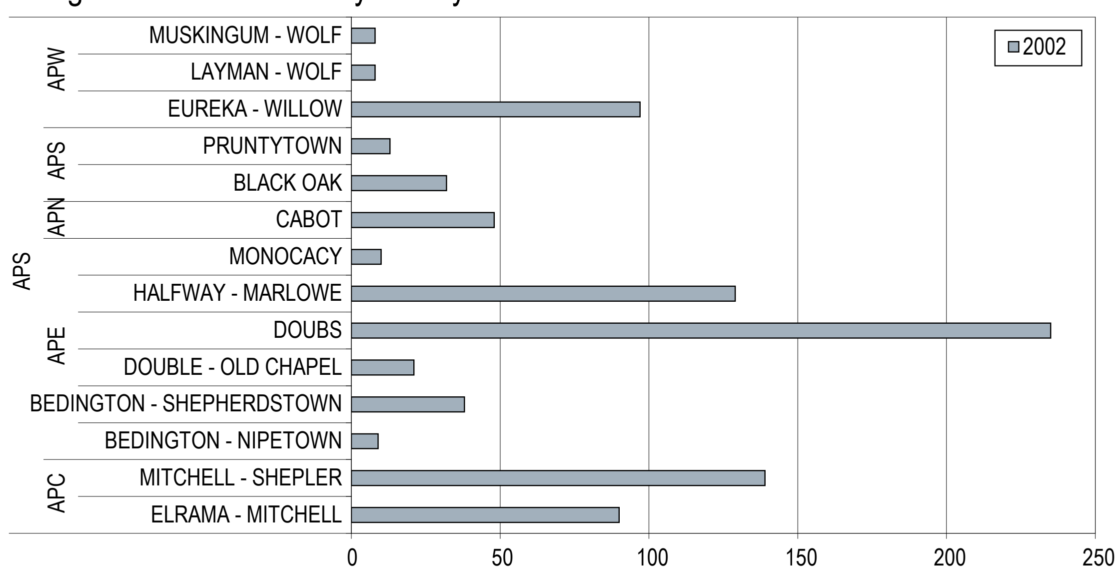
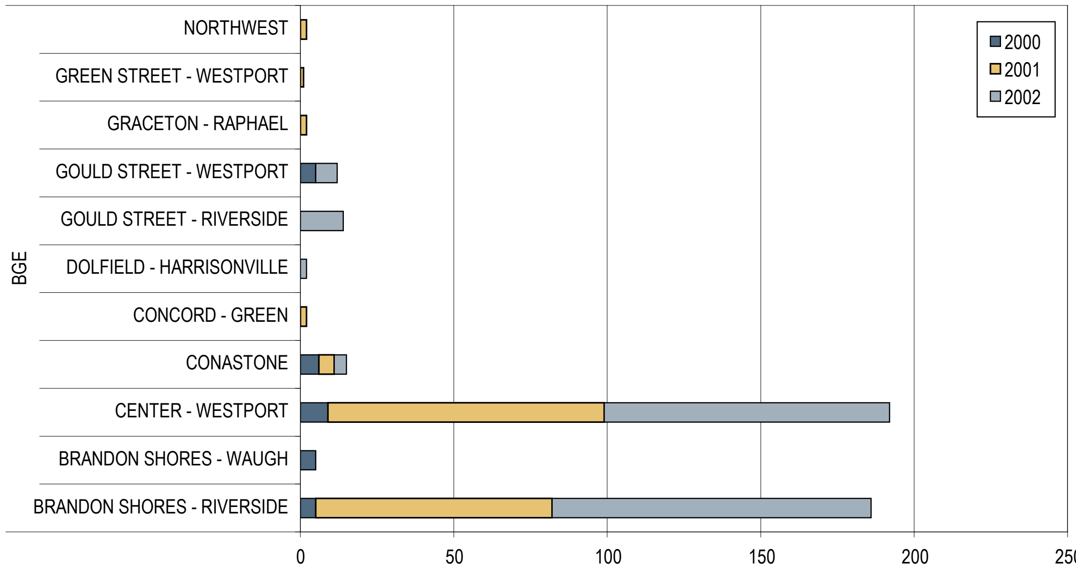


Figure 6-10 illustrates the BGE Zone constraints, none of which were frequently constrained during 2002. Most of the constraints affected small load pockets or represented bottled generation. Bottled generation occurs when local operating constraints prevent full dispatch of economic generation at a plant.

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



Figures 6-11a, b, and c illustrate the occurrence of the DPL Zone constraints. As shown, the Delmarva Peninsula (DPLS) has experienced frequent constraints over the past three years. In 2000 and 2001, there was at least one active constraint on the peninsula during 27 percent and 32 percent of all hours, respectively. Many of these constraints were related to construction designed to relieve the congestion problem. There was a significant decrease in 2002 to a total of 791 constrained hours or nine percent of all hours. This decline can be directly attributed to the investment in transmission improvements and reinforcements during the past three years. Constraints on the peninsula (DPLS) have historically been much more frequent than those on the mainland (DPLN and SEPJM).

Figure 6-11a DPL Zone
Constrained Hours by Subarea

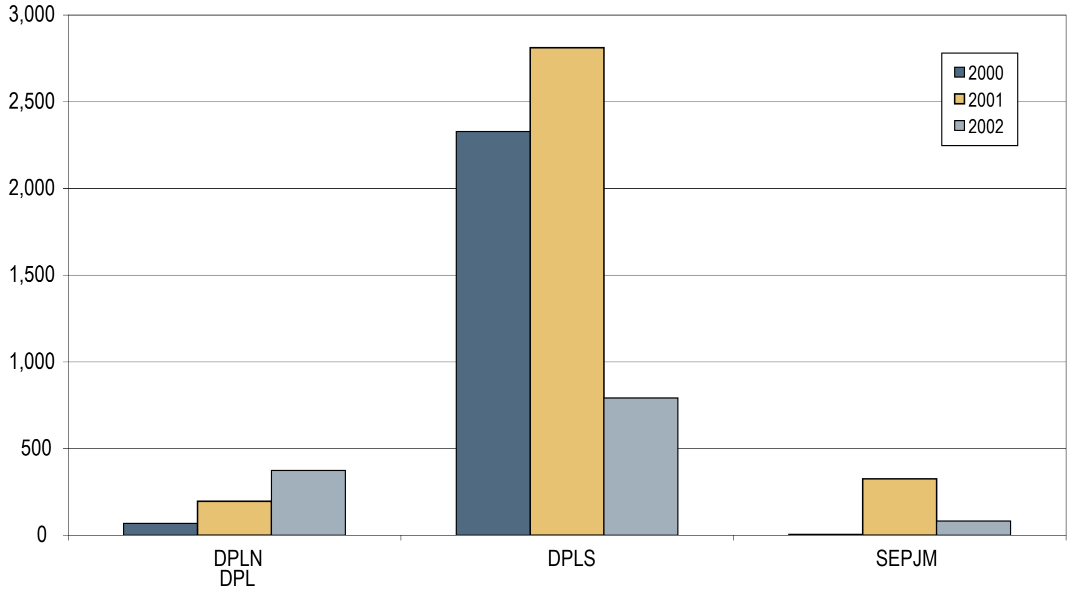


Figure 6-11b illustrates the occurrence of DPLS constrained events by facility. As shown, Mount Olive-Piney Grove 138 was constrained over 1,500 hours in 2001 but zero hours in 2002, mostly because of construction activities that did not occur in 2002. Hallwood-Oak Hall 69, Cheswold 138/69, and Indian River 230/138, and Church 138/69 were the only facilities constrained more than 100 hours in 2002, with none constrained for more than 300 hours. This represents a significant improvement from 2000 and 2001 when eleven and six facilities, respectively, were constrained for more than 100 hours. None of these constraints affected more than about two percent of PJM load.

Figure 6-11b DPL Zone (DPLS Subarea)
Congestion-Event Hours by Facility

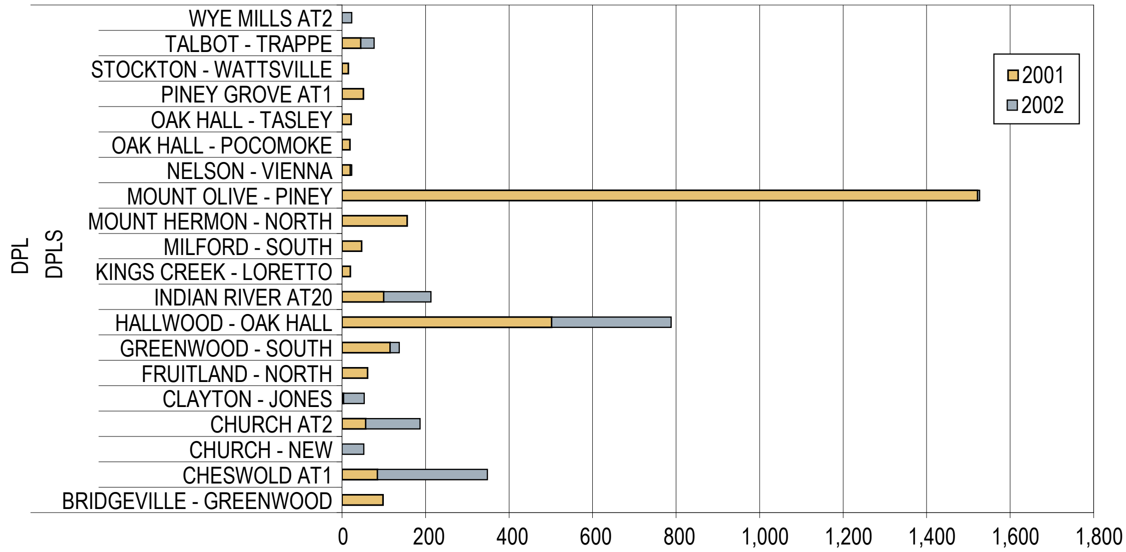
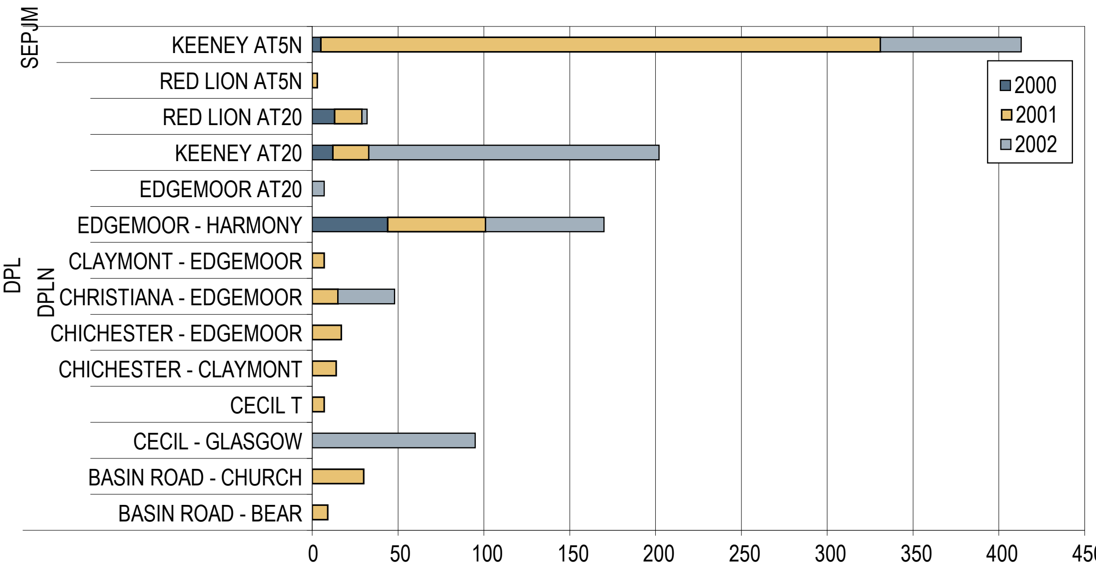


Figure 6-11c depicts the same information for the DPLN and Southeast PJM (SEPJM) Subareas. As shown, during 2002 Keeney 230/138 was the most constrained facility in DPLN, constrained 175 hours. Keeney 500/230, constrained 90 hours, was the most constrained facility in SEPJM. These two represented the largest increase and decrease in constraint frequency between 2001 and 2002, respectively for these areas. No other facility was constrained for more than 100 hours in 2002.

Figure 6-11c DPL Zone (DPLN and SEPJM Subareas) Congestion-Event Hours by Facility



DPLS aggregate load congestion costs were estimated for 2001 and 2002 for the hours when DPLS was congested by constraints on the peninsula or in DPLN and Southeast PJM, but impacting the peninsula. The local, constrained energy costs were calculated as the product of the DPLS aggregate load and DPLS aggregate LMP. An unconstrained energy cost was calculated as the product of the DPLS load and an unconstrained, reference LMP. Selection of the unconstrained, reference LMP was dictated by the location of the dominant constraint affecting the peninsula. Care must be taken when choosing an unconstrained reference price so that it accurately represents the price of unconstrained energy that would be available to DPLS. For example, it is often the case that, when Keeney 500/230 is constrained, the LMP at Keeney 500 is lower than the system energy price. Under such circumstances, using Keeney 500 as the unconstrained reference would overstate congestion costs.

LMP patterns during constrained hours were analyzed to determine the best reference prices. Results indicated that Keeney 138 was the best DPLS reference for hours when DPLS constraints were exclusively active; Basin Road 138 was best when DPLN constraints were in effect; and the DPLN aggregate was best when Keeney 500/230 was constrained.

Estimated in this manner, DPLS congestion costs were estimated to be $25.6 million and $23 million in 2001 and 2002 respectively, with $32 million of the two-year total attributable to constraints on the peninsula and the remaining $16 million of congestion charges caused by constraints in Northern DPL and Southeastern PJM.

The JCPL Zone experienced very few internal transmission constraints, 10 hours in 2000, none in 2001, and 20 hours in 2002. No figures have been provided for this zone.

Figure 6-12 illustrates the METED Zone constraints. It shows that transmission constraints in the Western METED subarea (MEW), primarily York County, Pennsylvania, constituted most of the congestion events in this zone during the period of the analysis. The Jackson and Yorkanna 230/115 transformers and Carlisle-Gardners 115 all were constrained over 100 hours each in 2002 and accounted for the bulk of the slight increase in occurrence of transmission constraints in this subarea. Hummelstown-Middletown 230 accounted for the bulk of the constrained hours and 2002 increase in the South-Central Pennsylvania (SCPA) subarea.

Figure 6-12 METED Zone
Congestion-Event Hours by Facility

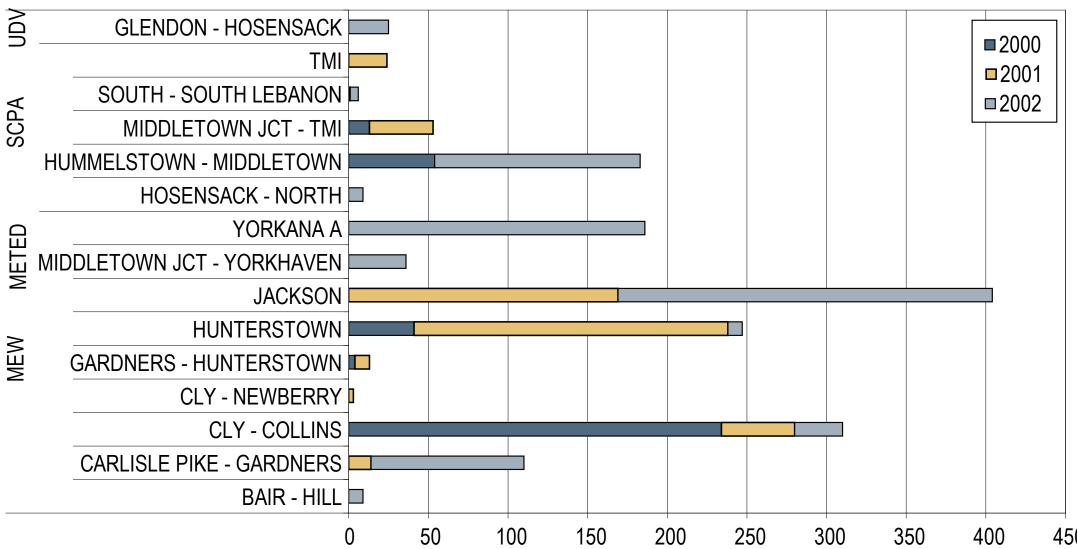


Figure 6-13 illustrates PECO Zone constraints. It shows that only two constraints were active for more than 100 hours, Cromby-Moser 69 for 335 hours, and the PECO North reactive interface (PECO North) for 135 hours. Cromby-Moser affected load at just a few small substations, while PECO North impacted about 20 percent of PECO Zone load. These two constraints accounted for the bulk of the 360-hour increase between 2001 and 2002.

Figure 6-13 PECO Zone
Congestion-Event Hours by Facility

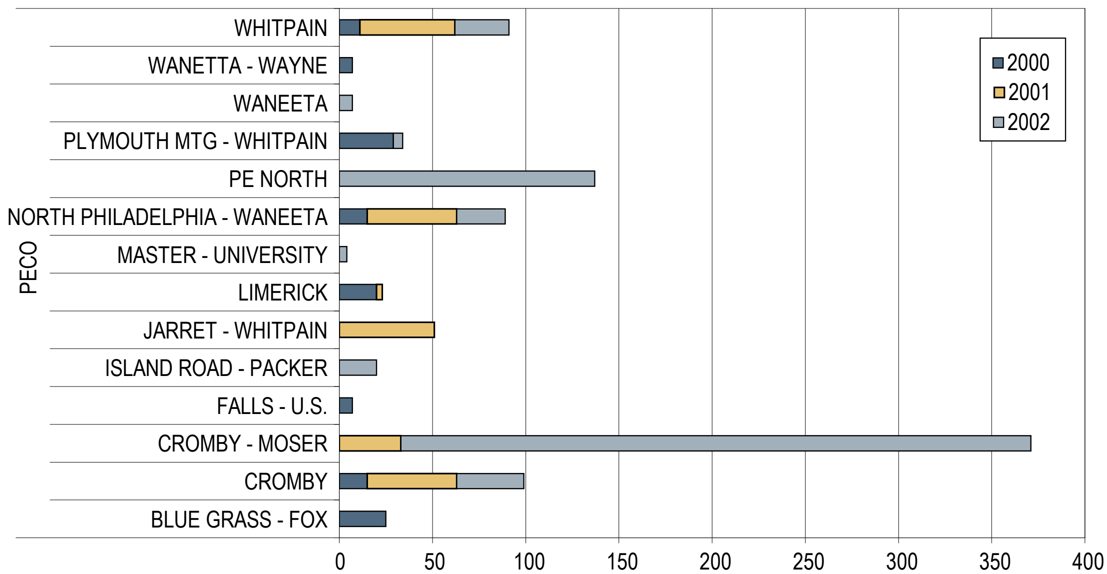
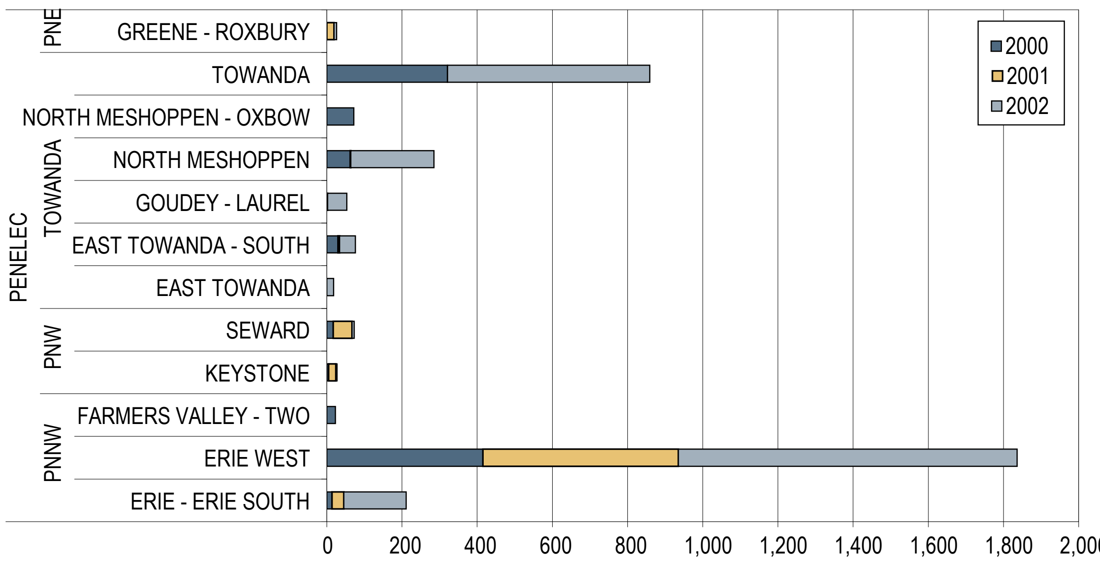


Figure 6-14 illustrates the PENELEC Zone constraints. It shows that constraints in Northwestern PENELEC have recently more than doubled in frequency, with the Erie West 230/115 transformer constrained for 520 hours in 2001, increasing to 901 hours in 2002, 10 percent of all hours. This facility affected about two percent of PJM load. Erie West-Erie South 345 was constrained 175 hours in 2002, two percent of all hours. The Towanda reactive interface, which last occurred in 2000 and affects about one percent of PJM load, was constrained for 525 hours in 2002. This constraint affects PJM-NYISO energy transfers through upstate Pennsylvania.

Figure 6-14 PENELEC Zone
Congestion-Event Hours by Facility



Congestion costs, associated with the Erie West 345/115 transformer which constrains, on average, 950 MW of load in Northwestern Pennsylvania, were estimated for the 2001 to 2002 period. The local, constrained energy costs were calculated for each constrained hour by taking the product of the constrained load and local LMP. An unconstrained energy cost was then calculated by taking the product of the constrained load and an unconstrained, reference LMP, in this case Keystone 500. Congestion costs are equal to the difference between the constrained and unconstrained energy costs. These costs totaled and $21 million in 2001 and $36.8 million in 2002.

The PEPCO Zone experienced very few internal transmission constraints, 12 hours in 2000, 34 in 2001, and 13 in 2002. No figures have been provided for this zone.

Figure 6-15 illustrates the frequency of PPL Zone constraints. There was a 200-hour increase in the Northern PPL reactive constraint (PL North) which occurred during October and November 2002. Other than this exception, transmission constraints rarely occurred in this zone.

Figure 6-15 PPL Zone
Congestion-Event Hours by Facility

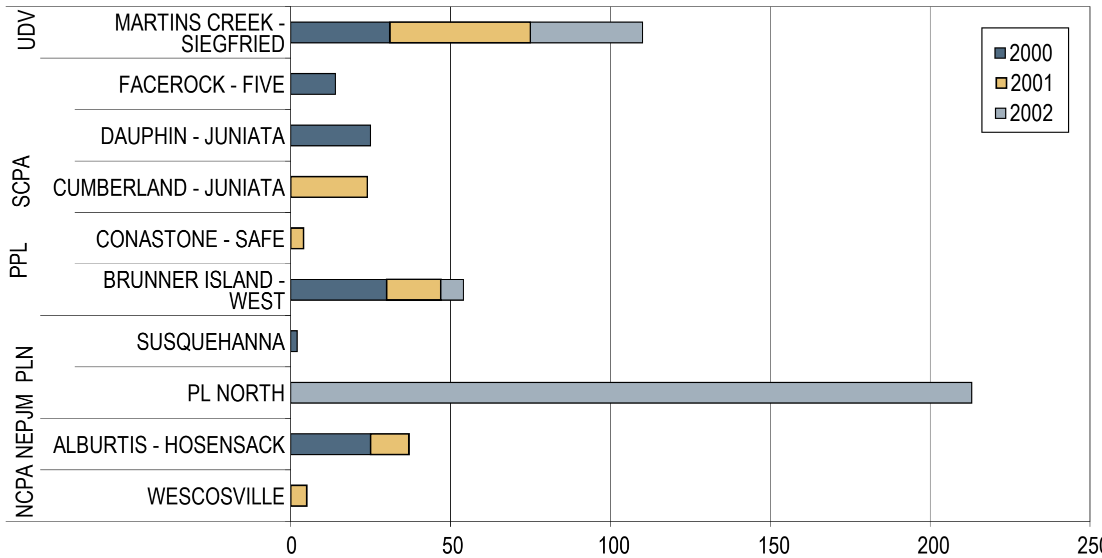


Figure 6-16 illustrates constraint occurrences in the PSEG Zone. As shown, constraints in Northern PSEG (PSN), primarily Roseland-Cedar Grove 230 which affects nearly one-half of PSEG Zone load, were half as frequent in 2002 as in 2001. The addition of new generating capacity was the likely reason for this decrease.

Constraints at Edison-Meadow Road 138 in North-central PSEG (PSNC) doubled in frequency from 180 to 370 hours in 2001 and 2002. The southern part of PSEG Zone, South-central PSEG (PSSC) and Southern (SNJ), was rarely constrained.

Figure 6-16 PSEG Zone
Congestion-Event Hours by Facility

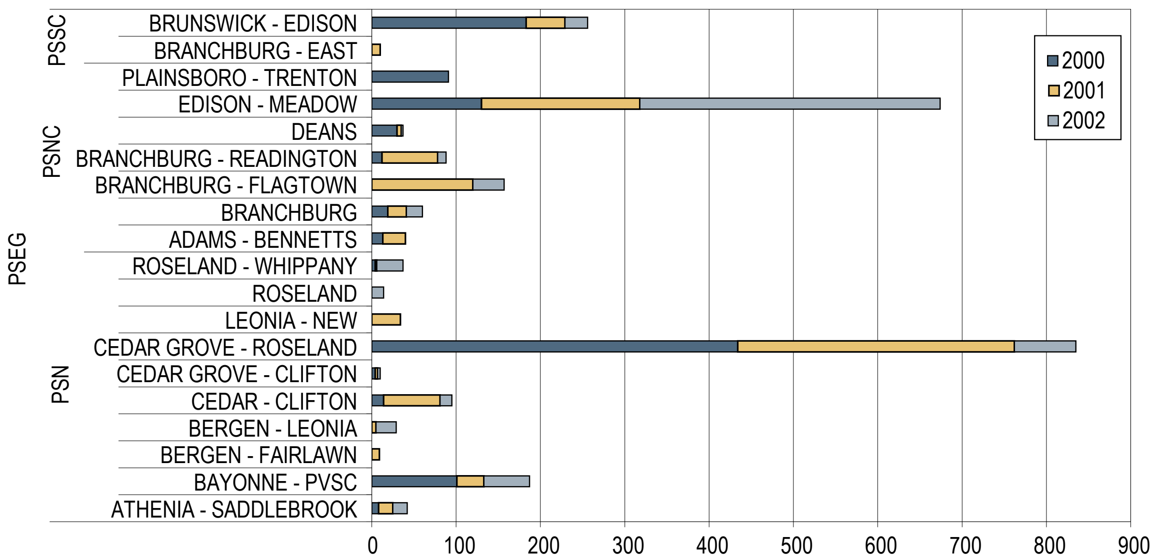


Table 6-5 lists constraint event-hours by facility type and voltage.

Table 6-5—Constraint Event Summary by Facility Type and Voltage Class

Type	Voltage	Congestion-Event Hours					Percent of Congestion-Event Hours				
	(kV)	1998	1999	2000	2001	2002	1998	1999	2000	2001	2002
All	All	1,244	2,134	6,941	8,435	11,657	100%	100%	100%	100%	100%
All	500	203	189	562	759	1,926	16%	9%	8%	9%	17%
All	345	71	148	14	38	1,107	6%	7%	0%	0%	9%
All	230	588	818	1,294	1,625	1,408	47%	38%	19%	19%	12%
All	138	365	819	869	744	2,056	29%	38%	13%	9%	18%
All	115	17	13	1,204	1,154	2,527	1%	1%	17%	14%	22%
All	69	0	147	2,993	4,115	2,619	0%	7%	43%	49%	22%
All	34	0	0	5	0	14	0%	0%	0%	0%	0%
Line	All	1,002	1,383	4,740	5,507	4,508	81%	65%	68%	65%	39%
Transformer	All	225	345	1,045	2,176	4,427	18%	16%	15%	26%	38%
Interface	All	17	406	1,156	752	2,722	1%	19%	17%	9%	23%
Interface	500	17	146	546	747	1,668	1%	7%	8%	9%	14%
Line	500	69	0	16	12	84	6%	0%	0%	0%	1%
Line	345	14	2	14	38	233	1%	0%	0%	0%	2%
Transformer	345	57	146	14	38	233	5%	7%	0%	0%	2%
Interface	230	0	260	240	0	350	0%	12%	3%	0%	3%
Line	230	540	454	912	1,164	658	43%	21%	13%	14%	6%
Transformer	230	165	147	142	461	400	13%	7%	2%	5%	3%
Line	138	362	767	773	408	1,163	29%	36%	11%	5%	10%
Transformer	138	3	52	96	336	893	0%	2%	1%	4%	8%
Interface	115	0	0	321	0	538	0%	0%	5%	0%	5%
Line	115	17	13	348	214	413	1%	1%	5%	3%	4%
Transformer	115	0	0	535	940	1,576	0%	0%	8%	11%	14%
Interface	69	0	0	49	5	166	0%	0%	1%	0%	1%
Line	69	0	147	2,672	3,671	1,943	0%	7%	38%	44%	17%
Transformer	69	0	0	272	439	510	0%	0%	4%	5%	4%
Line	34	0	0	5	0	14	0%	0%	0%	0%	0%