Section 5 – Ancillary Service Markets

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

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

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

Overview

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

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

Regulation Market Structure

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

Regulation Market Performance

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

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

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

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

Spinning Reserve Market Structure

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

Spinning Reserve Market Performance

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

Regulation

Regulation Market Structure

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

The PJM Mid-Atlantic Region has different, areawide regulation requirements for on-peak hours (hours ending 0600 to 2400 hours) and off-peak hours (hours ending 0100 to 0500 hours).[3] The regulation requirement for the peak period is 1.1 percent of the peak load forecast; for the off-peak period it is 1.1 percent of the valley load forecast.[4] During 2003, requirements ranged from approximately 750 MW of regulation capability for the peak period to approximately 220 MW for the off-peak period.

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

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

Table 5-1 PJM System Regulation Market HHI Values

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

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

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

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

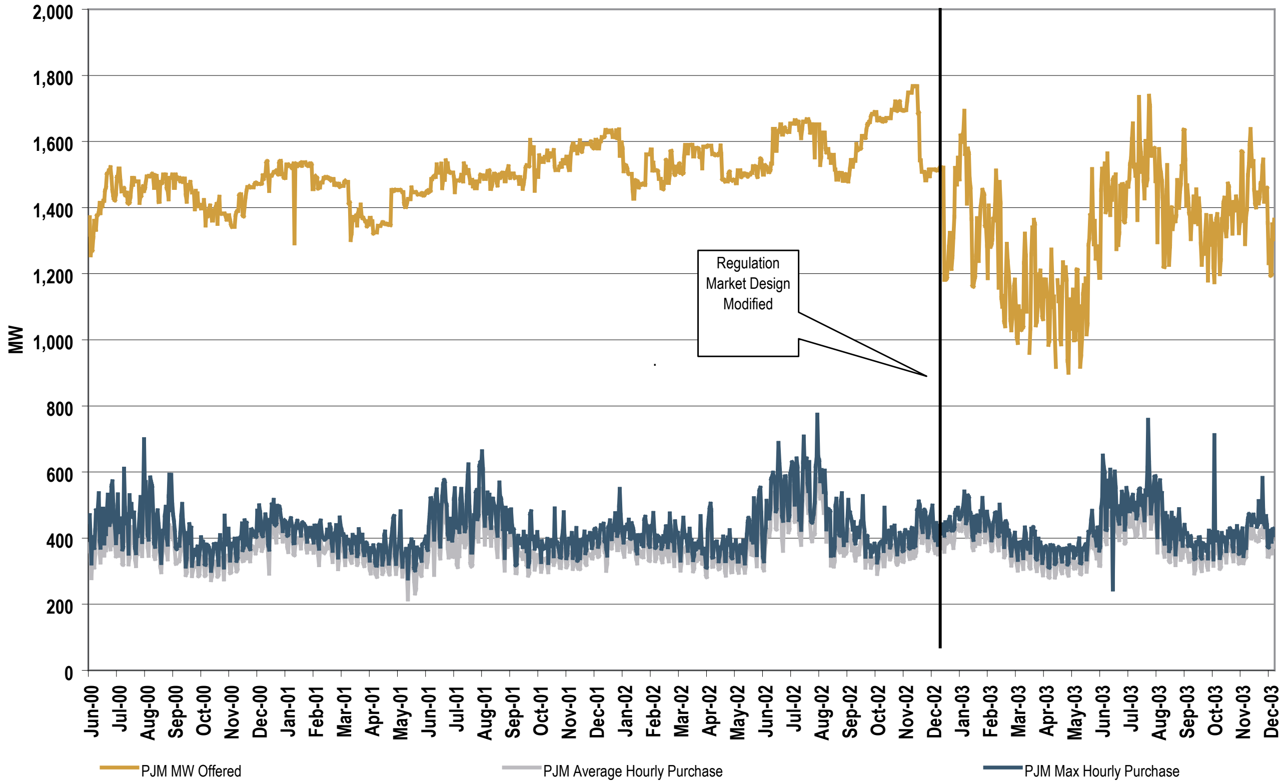
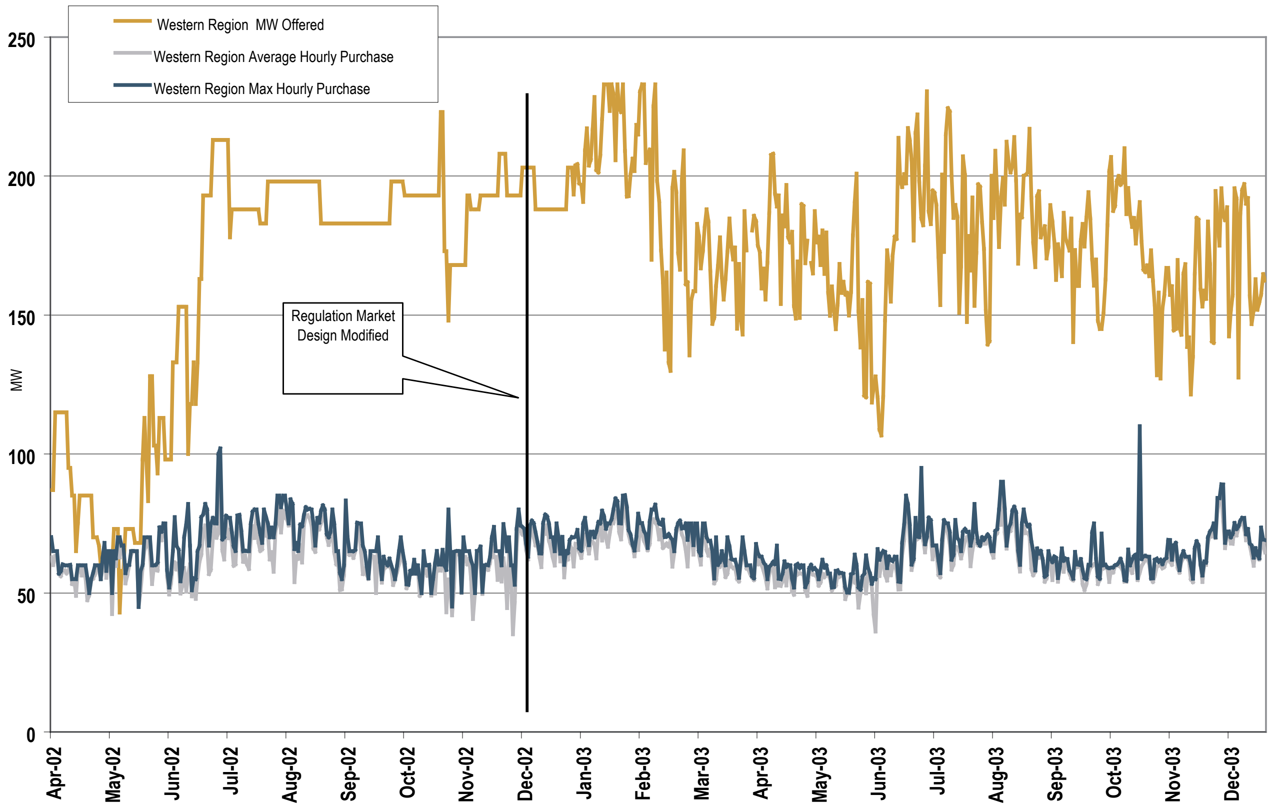


Figure 5-2 PJM Western Region Regulation MW Offered versus MW Purchased



Regulation Market Performance

Regulation Offers

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

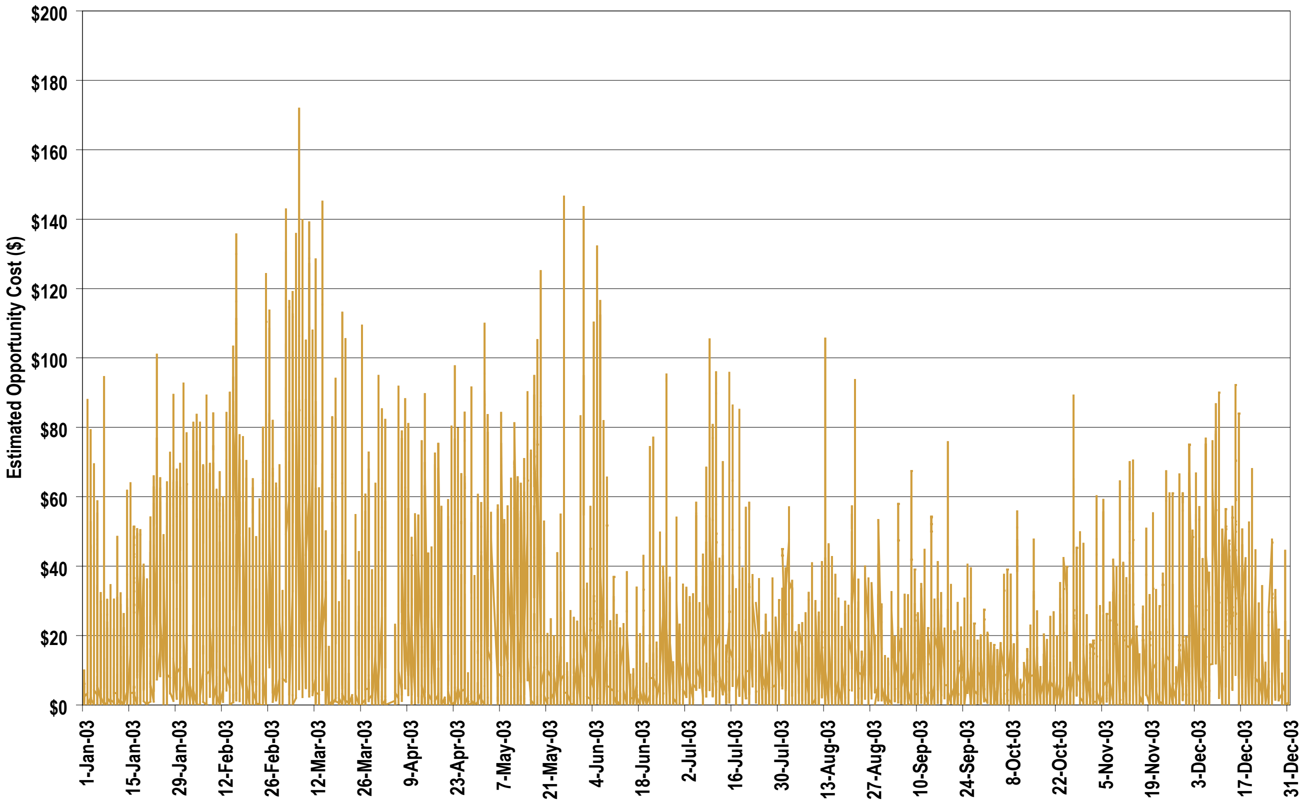
The Spinning Reserve and Regulation Markets are cleared simultaneously and cooptimized to reduce the cost of the combined products. In contrast to the previous PJM Regulation Market design, the current Regulation Market is cleared on a real-time instead of a day-ahead basis, and regulation prices are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

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

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

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

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



Regulation Prices

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

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

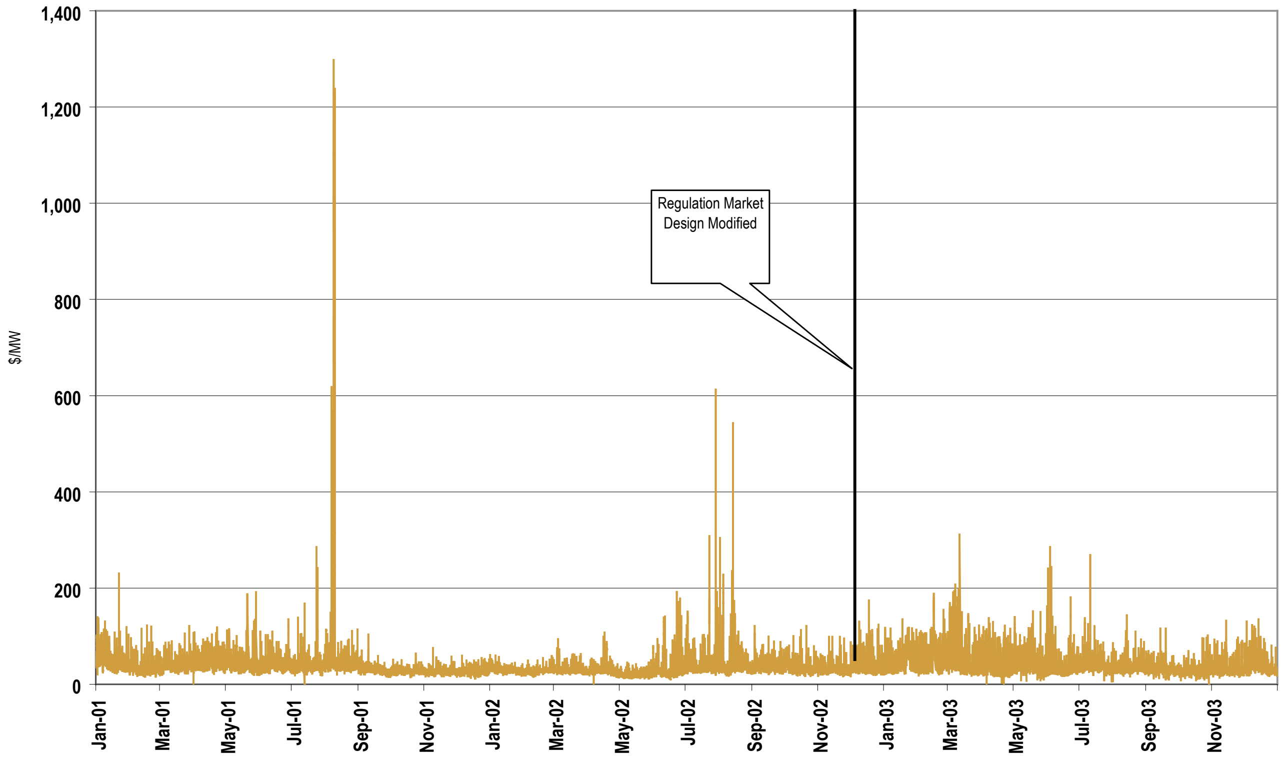


Figure 5-5 PJM Western Region Hourly Regulation Cost per MW

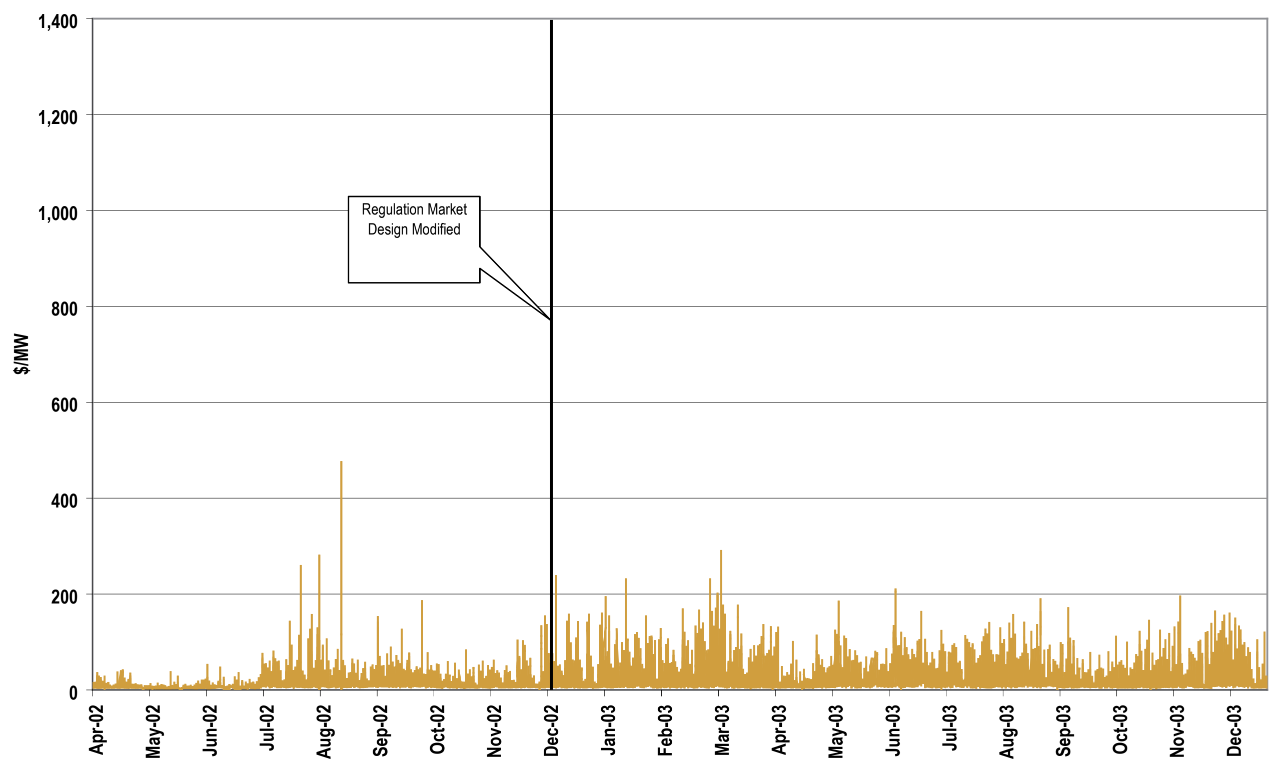


Figure 5-6 and Figure 5-7 compare the regulation cost per MW to the demand for regulation for the period from January 1999 through December 2003. Since the introduction of a Regulation Market, the per-unit cost of regulation has spiked when system LMP has spiked. Demand for regulation is a linear function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

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

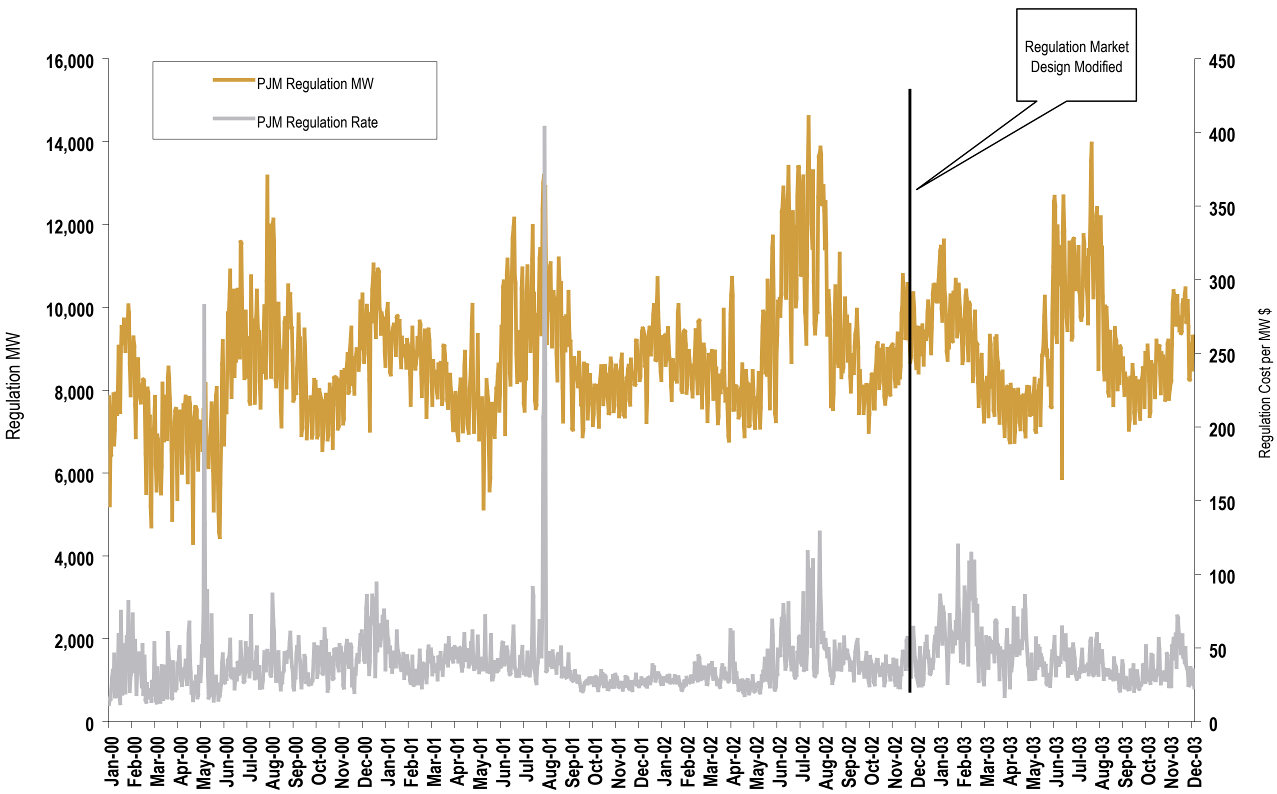


Figure 5-7 PJM Western Region Monthly Regulation MW Purchased Compared to Cost per Unit

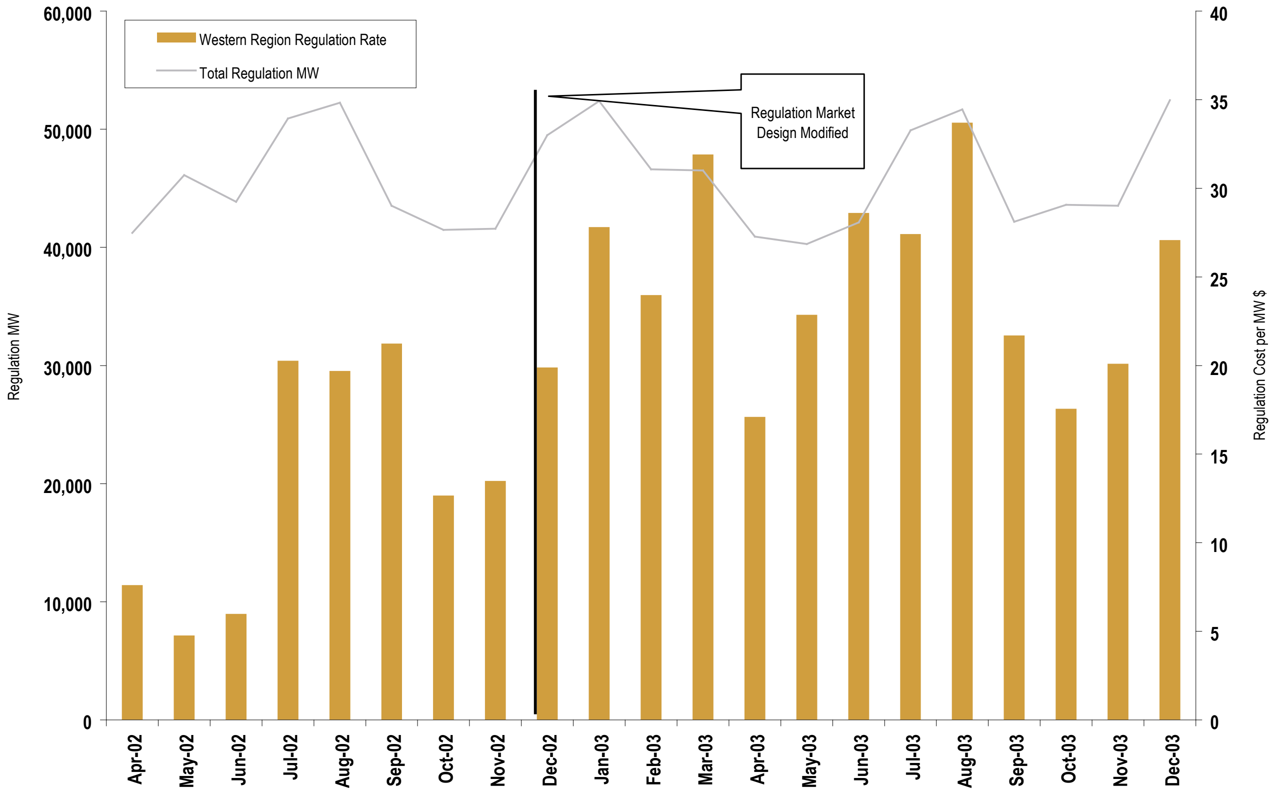
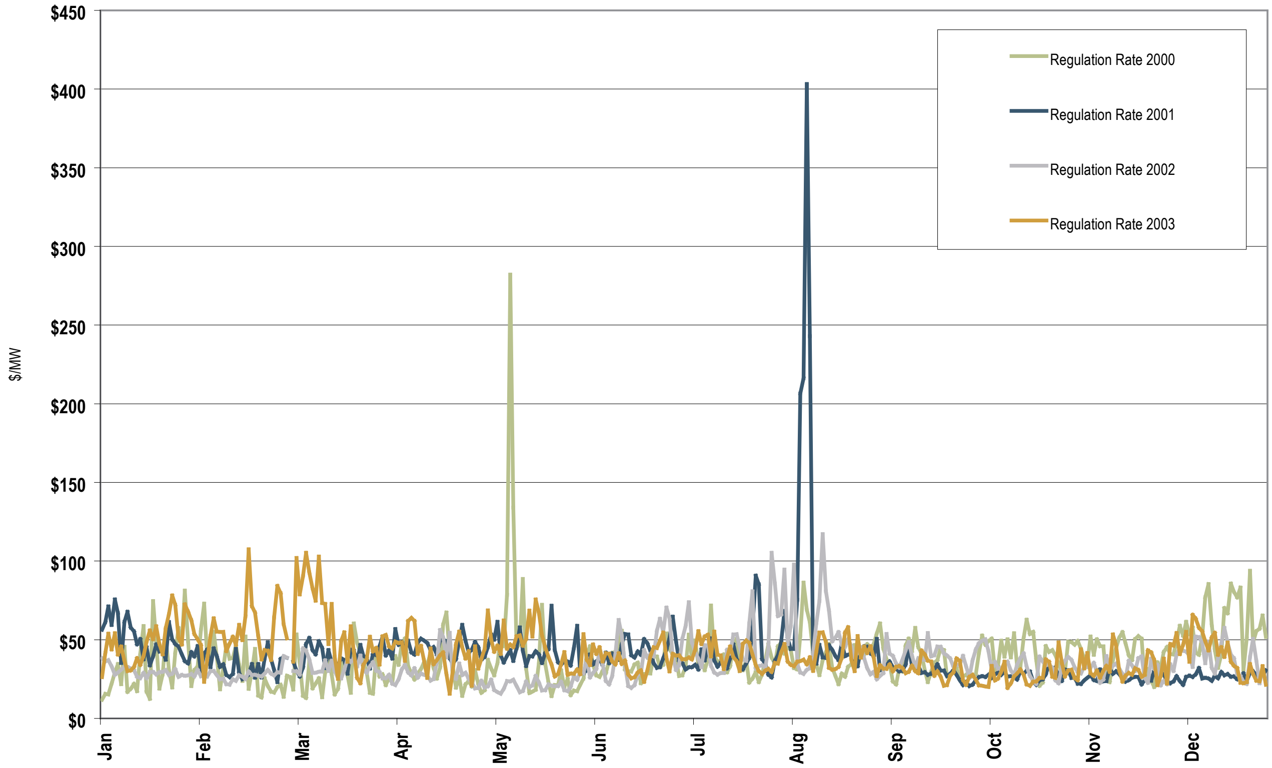


Figure 5-8 compares the average daily cost per MW of regulation for 2000, 2001, 2002 and 2003 (Figure 5-8 includes both the PJM Mid-Atlantic and the PJM Western Regions). The cost per MW of regulation for the PJM Mid-Atlantic and PJM Western Regions was 14 percent higher in 2003 than in 2002. In the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

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



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

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

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

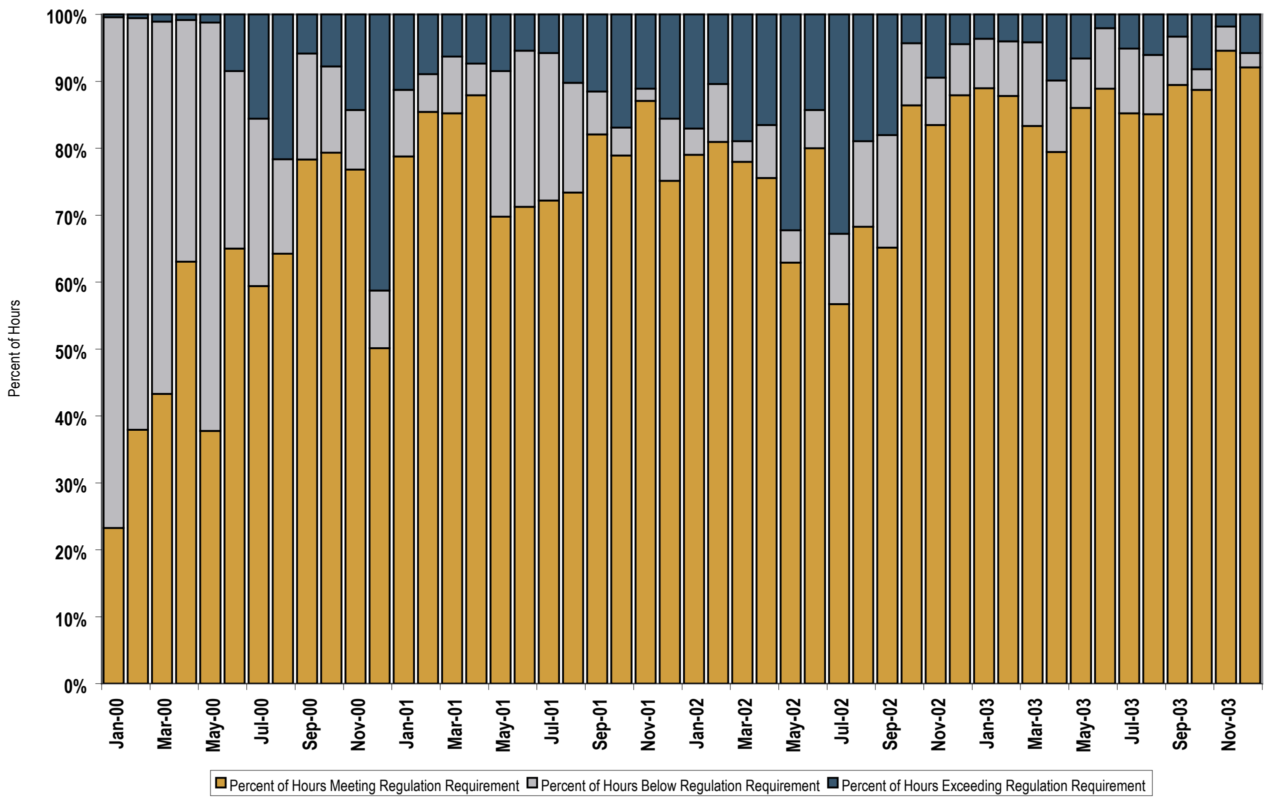
8 This is true in the PJM Mid-Atlantic Region, but is not true in the PJM Western Region.

Regulation Availability

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

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

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



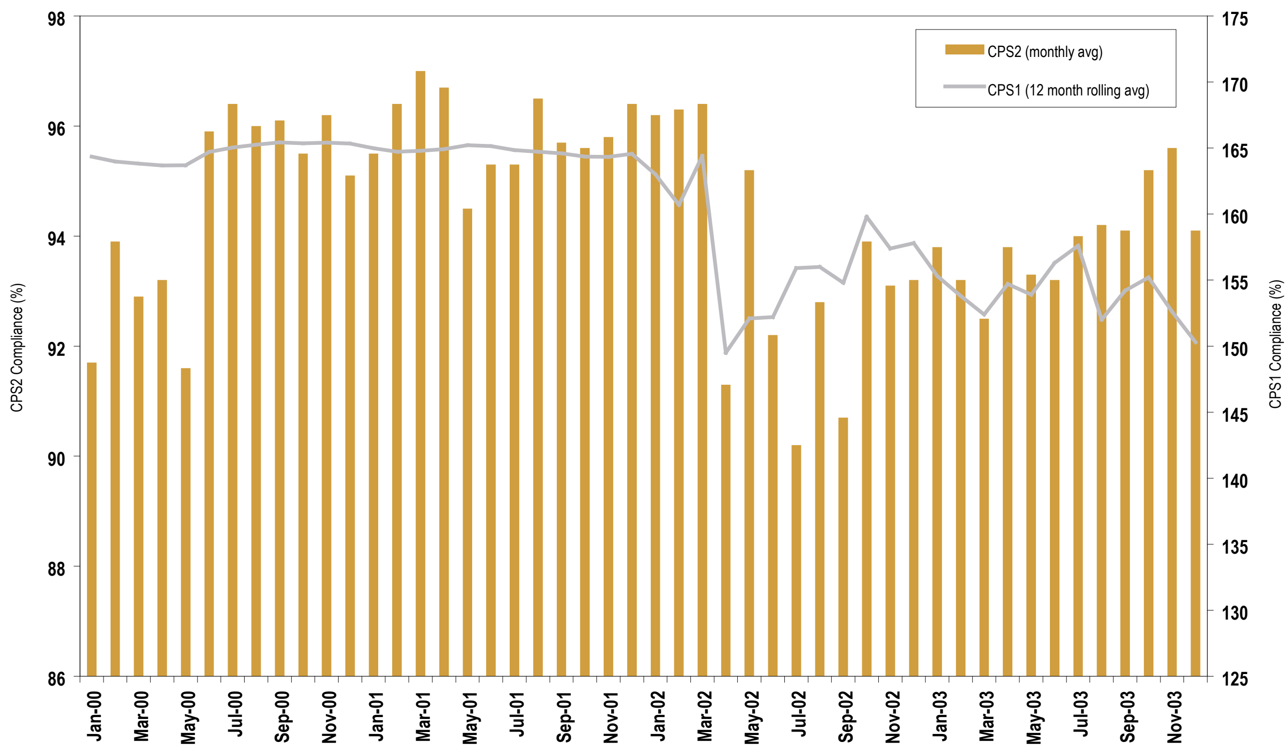
Regulation helps to maintain the balance between load and generation by moving the output of selected generators up and down via an automatic control signal.[9] While the improved availability of regulation illustrated in Figure 5-9 is important, the ultimate success of regulation in balancing load and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

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

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

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

Figure 5-10 CPS1 and CPS2 Performance



Spinning Reserve Service

Spinning Reserve Market Structure

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

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

PJM introduced a market in spinning reserve on December 1, 2002. Before the Spinning Reserve Market, Tier 1 spinning reserve had not been compensated directly and Tier 2 spinning reserve had been compensated on a unit-specific, cost-based formula.

Under the Spinning Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to provide a response when needed. Tier 1 spinning payments or credits are equal to the integrated increase in MW output from each generator over the length of a spinning event, times the spinning energy premium less the hourly integrated LMP. The spinning energy premium is defined as the average of the five-minute LMPs calculated during the spinning event plus $50 per MWh.[11]

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

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

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

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

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

Spinning Reserve Market Performance

Spinning Reserve Offers

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

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

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

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

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

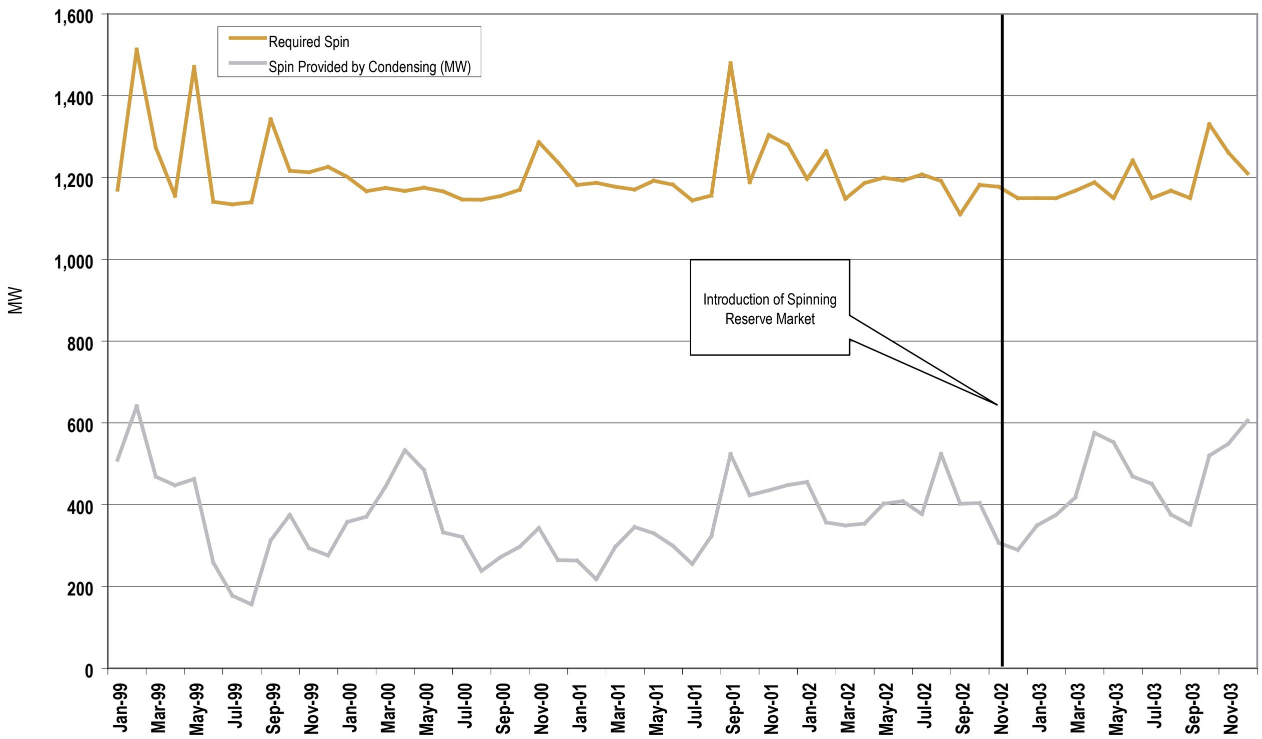
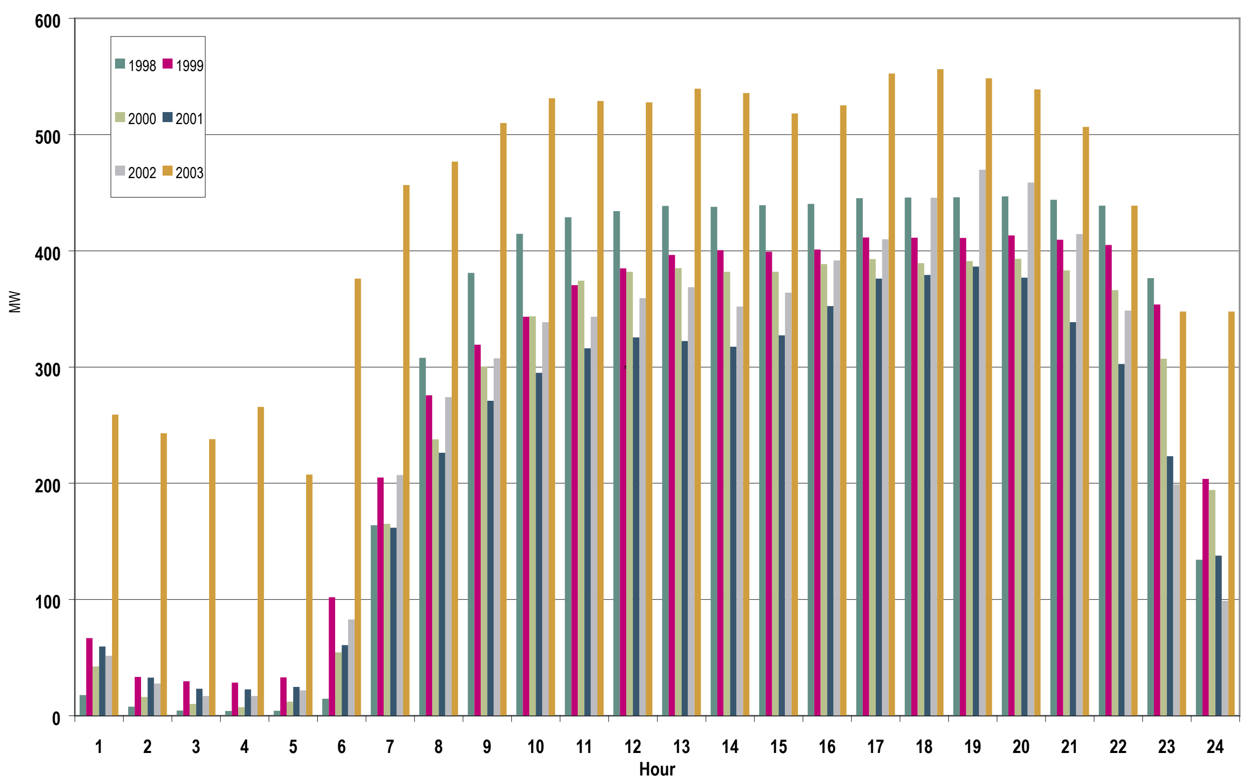


Figure 5-12 shows the annual average hourly Tier 2 spinning MW that PJM has purchased since 1998. Noticeably, these Tier 2 spinning MW are higher during 2003 than during prior years. Total spinning requirements were higher in 2003 and PJM operators relied more heavily on Tier 2 spinning in 2003, after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

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



Spinning Reserve Prices

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

Figure 5-13 Total Tier 2 Spinning Credits per MW

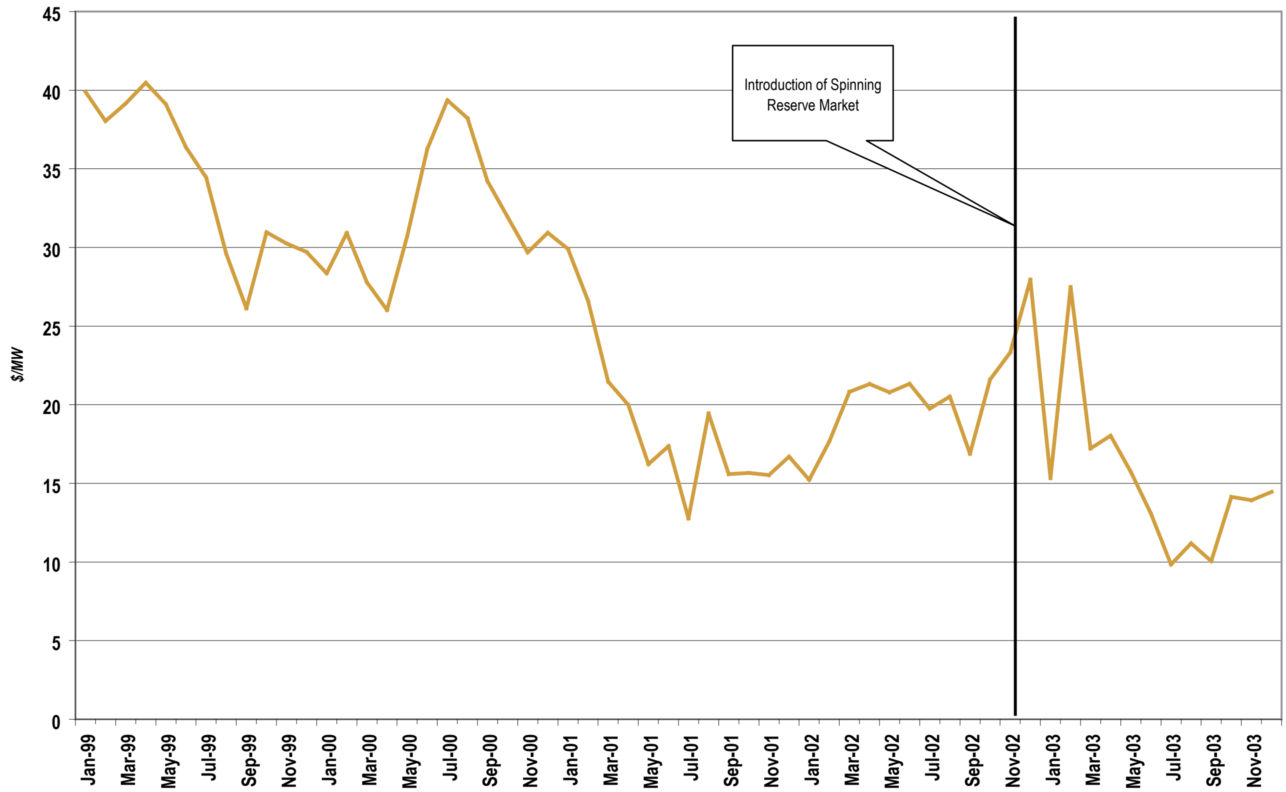


Figure 5-14 displays Spinning Reserve Market Tier 2 market-clearing prices (SRMCP) for 2003. Price spikes were seen at times in the period from March through July and again in October. As was true in the Regulation Market, these spikes reflect the fact that the marginal units' opportunity costs were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

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

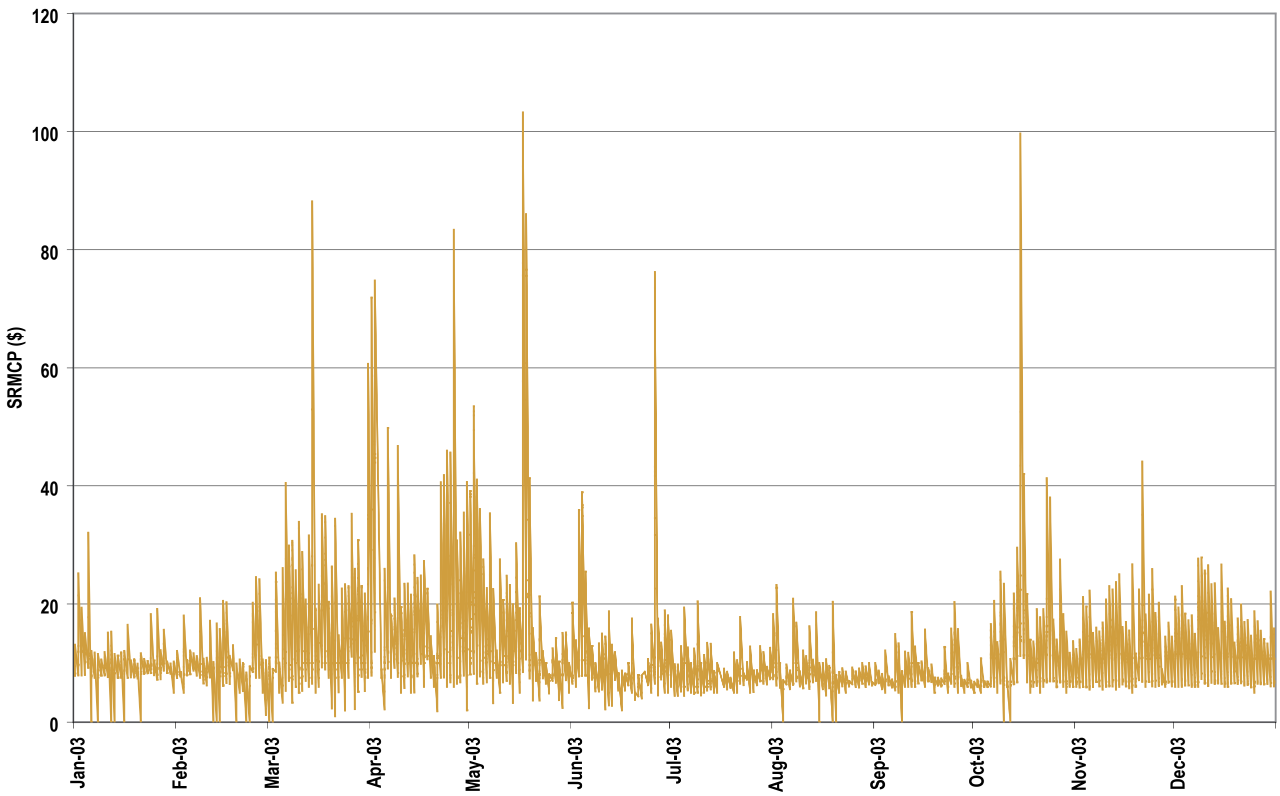
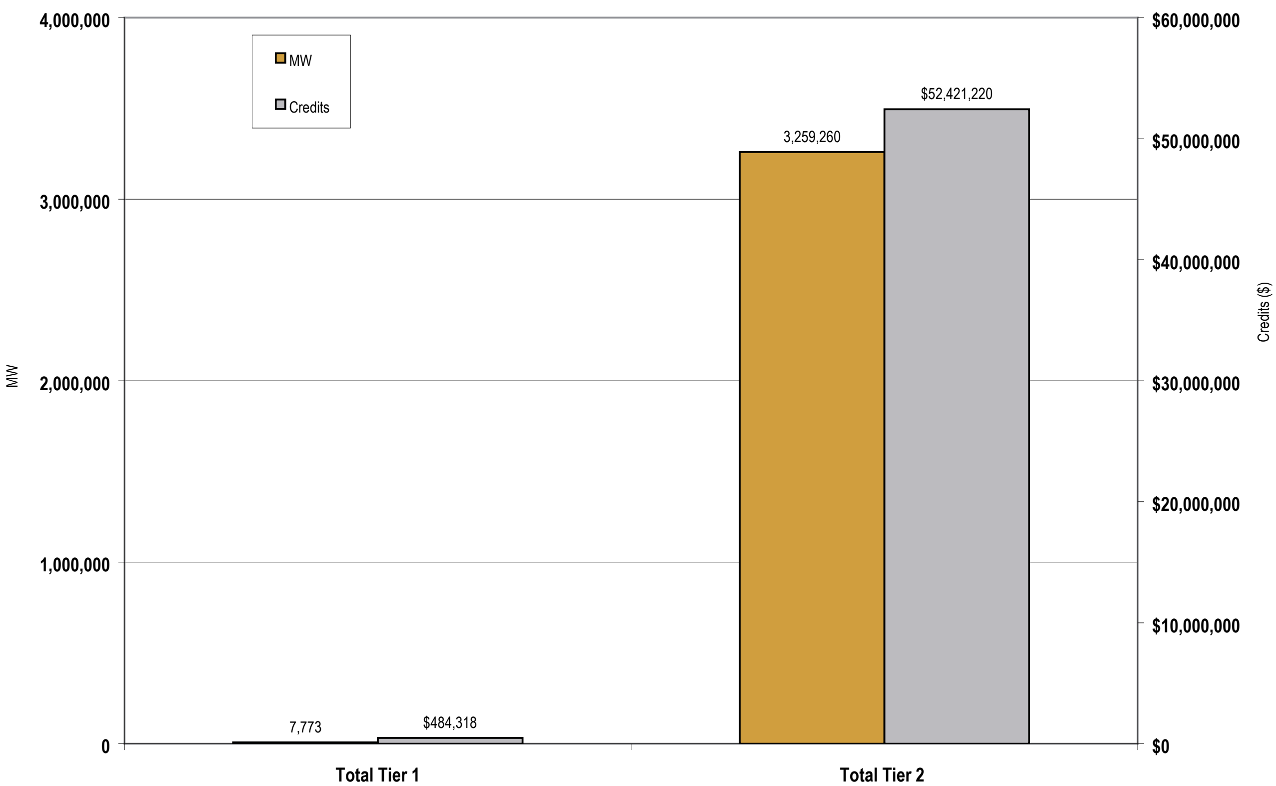


Figure 5-15 shows the level of Tier 1 and Tier 2 spinning reserve explicitly purchased from suppliers during 2003, the first full year of the new market. Tier 1 resources are paid only if they respond during spinning events while Tier 2 resources are paid for providing hourly reserves. As a result, more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

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



Section 6 – Congestion

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

Overview

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

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

- **Monthly Congestion.** Differences in monthly congestion costs continued to be substantial. In 2003, these differences were driven by loop flows, varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load.

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

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

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

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

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

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

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

In an order dated December 19, 2002, the FERC granted PJM full status as a regional transmission organization (RTO) and, among other rulings, directed PJM to make further compliance filings, principally to revise PJM's Regional Transmission Expansion Planning Protocol (RTEPP) to "more fully explain … how PJM's planning process will identify expansions that are needed to support competition" and to "provide authority for PJM to require upgrades both to ensure system reliability and to support competition."[3]

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

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Balancing Markets. Transmission congestion in the Day-Ahead Market can be directly hedged by using FTRs. Real-time congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the Day-Ahead Market.

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

- **Implicit Congestion Charges**. These charges are incurred by network customers in delivering their generation to their load and equal the difference between a participant's load charges and generation credits, less the participant's Spot Market bill. In the Day-Ahead Market, load charges are calculated as the sum of the demand at every bus times the bus LMP. Demand includes load, decrement bids and sale transactions. Generation credits are similarly calculated as the sum of the supply at every bus times the bus LMP, where supply includes generation, increment bids and purchase transactions. In the Balancing Market, load charges and generation credits are calculated the same way, using the differences between day-ahead and real-time demand and supply and valuing congestion using real-time LMP.

- **Explicit Congestion Charges**. These charges are incurred by point-to-point transactions and are equal to the product of the transacted MW and LMP differences between sources and sinks in the Day-Ahead Market. Balancing Market explicit congestion charges are equal to the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time LMP at the transactions' sources and sinks.

- **Spot Market Charges**. These charges are equal to the difference between total spot market purchase payments and total spot market sales revenues.

2 96 FERC ¶61,061 (2001).
3 101 FERC ¶61345 (2002).
4 See generally 104 FERC ¶61,124 (2003).

Total Congestion

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

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

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

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

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

Table 6-1 Total Congestion

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

Hedged Congestion

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

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

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

Although some months had congestion credit deficiencies, excess congestion charges collected in other months offset all but $23 million of the deficiencies, and FTRs were paid at 96 percent of the target allocation level in 2003, compared to 95 percent in 2002. Although aggregate FTRs provided a hedge against 96 percent of the target allocation level, all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

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

Monthly Congestion

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

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

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

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

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

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

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

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

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

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

Zonal Congestion

Constraints were examined by zone and categorized by their effect on regions as well as subareas. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones, and subareas consist of portions of one or more zones.

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

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

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

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

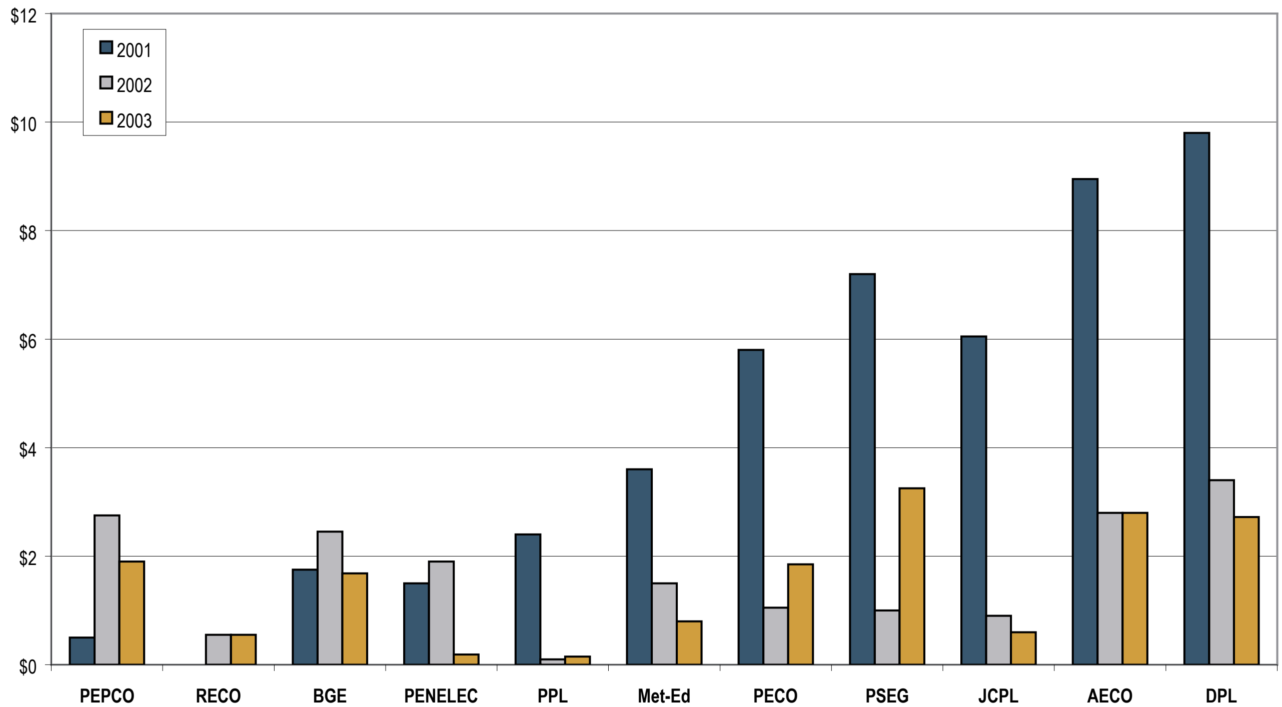
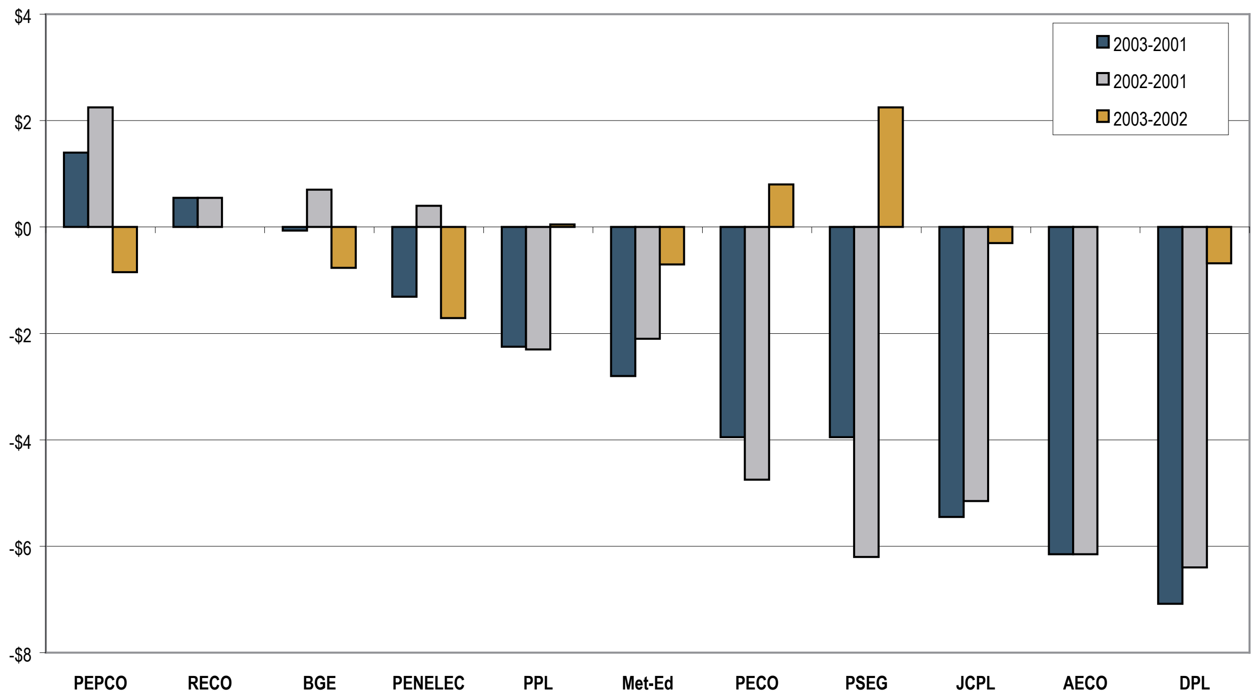


Figure 6-2 Year-to-Year Annual Zonal LMP Differences: Reference to Western Hub



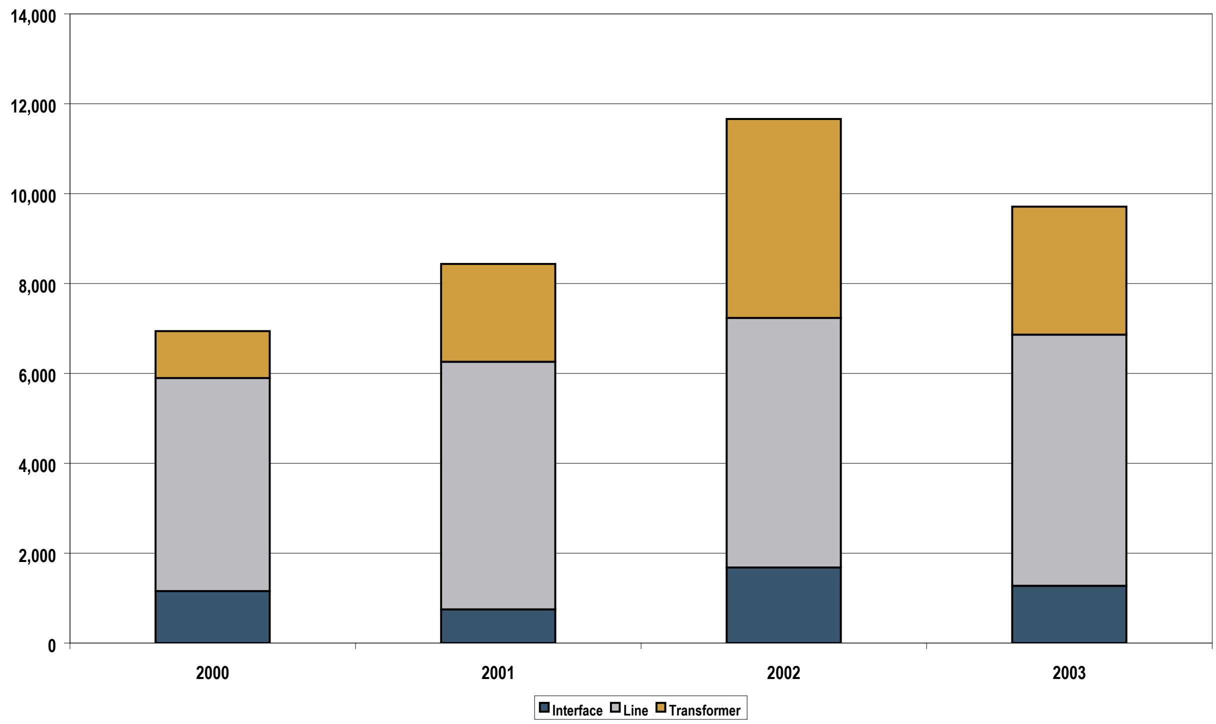
Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. Each constraint results in a separate congestion event. Constraints are often simultaneous and therefore total congestion event hours can exceed the number of hours in a year. In 2003, there were 9,711 congestion-event hours, a 17 percent decrease from 11,662 in 2002. By contrast, 174 different monitored facilities were constrained during 2003, an increase of 13 facilities over 2002.

Congestion by Facility Type

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

Figure 6-3 Congestion-Event Hours by Facility Type



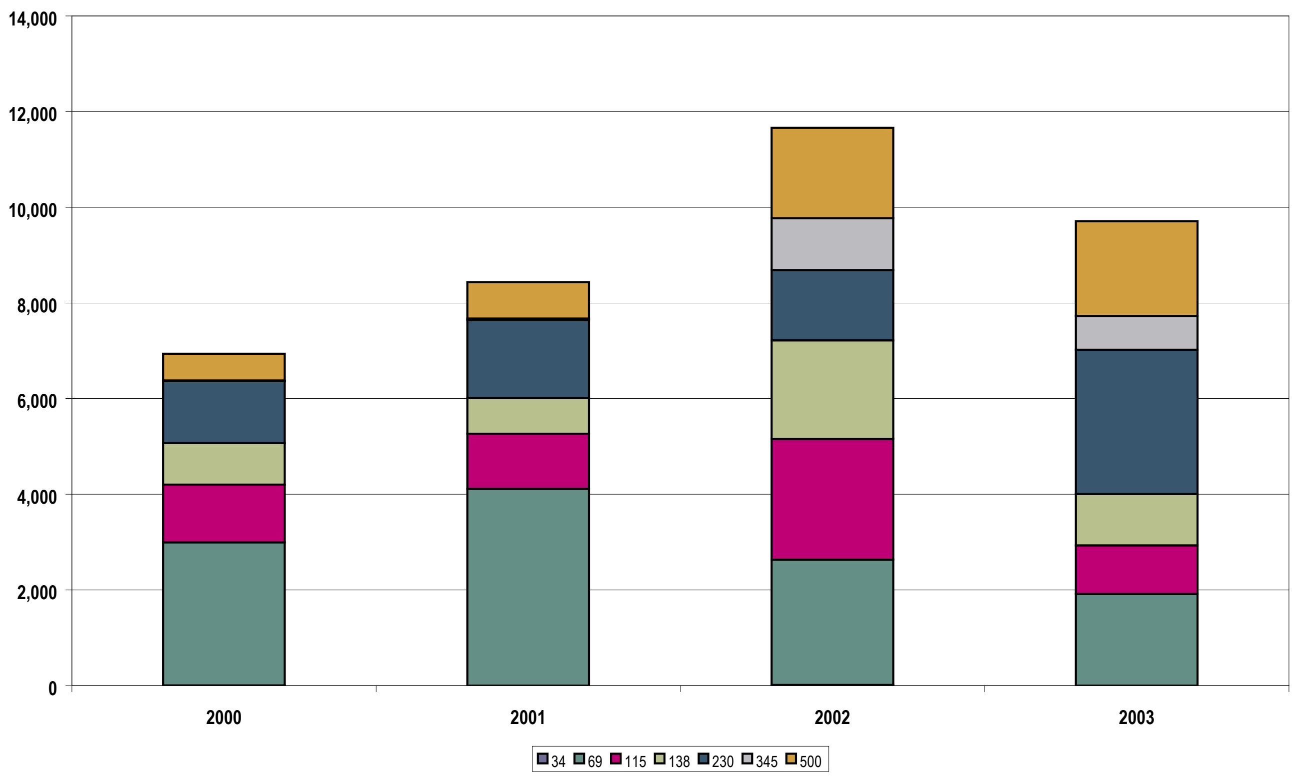
Transformer constraints occurred during 1,580 fewer hours in 2003 than in 2002, with the largest single decrease of 719 congestion-event hours coming from the Erie West 345/115 kV transformer. This resulted from the installation of an additional transformer at Erie West. The replacement of the Cheswold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

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

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

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

Figure 6-4 Congestion-Event Hours by Facility Voltage



Constraint Duration

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

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

Table 6-4 Constraint Duration Summary

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

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

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

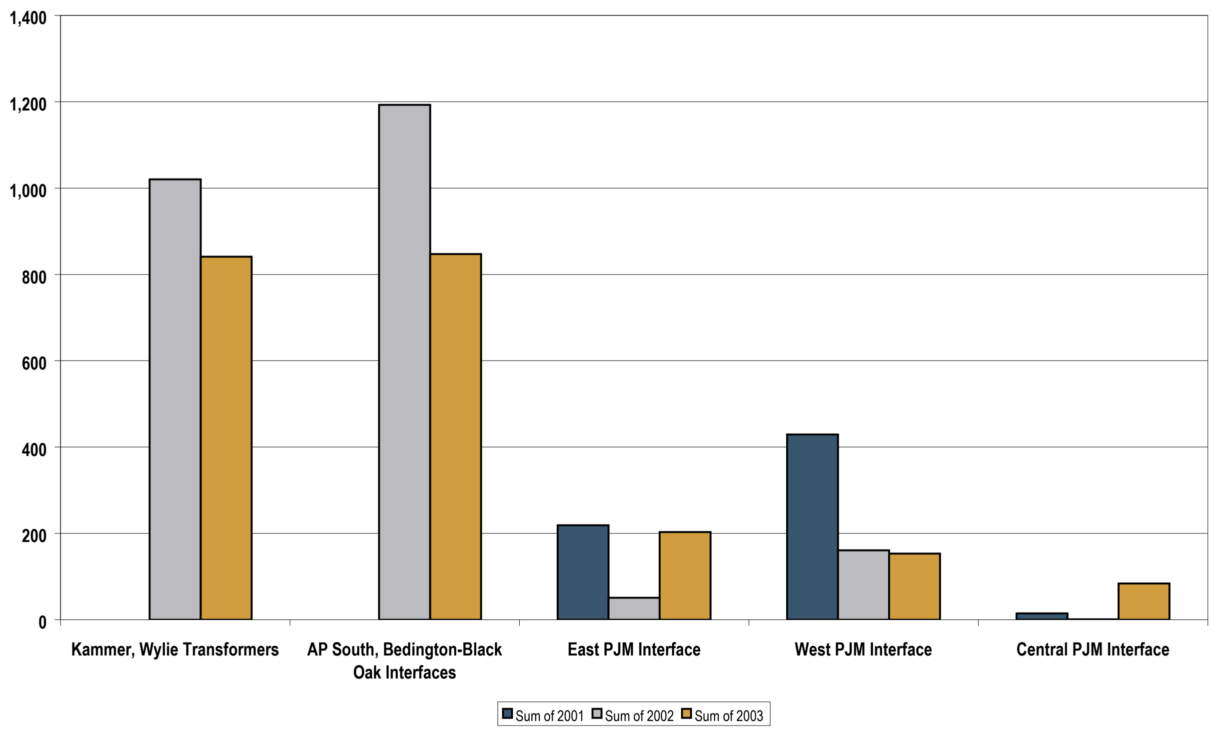
7 Percent of impacted load presented in Table 6-4 is an approximation as determined by distribution factor analysis. Any substation that has a distribution factor greater than 5 percent is deemed to be affected by a constraint.

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

Congestion-Event Hours by Facility

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

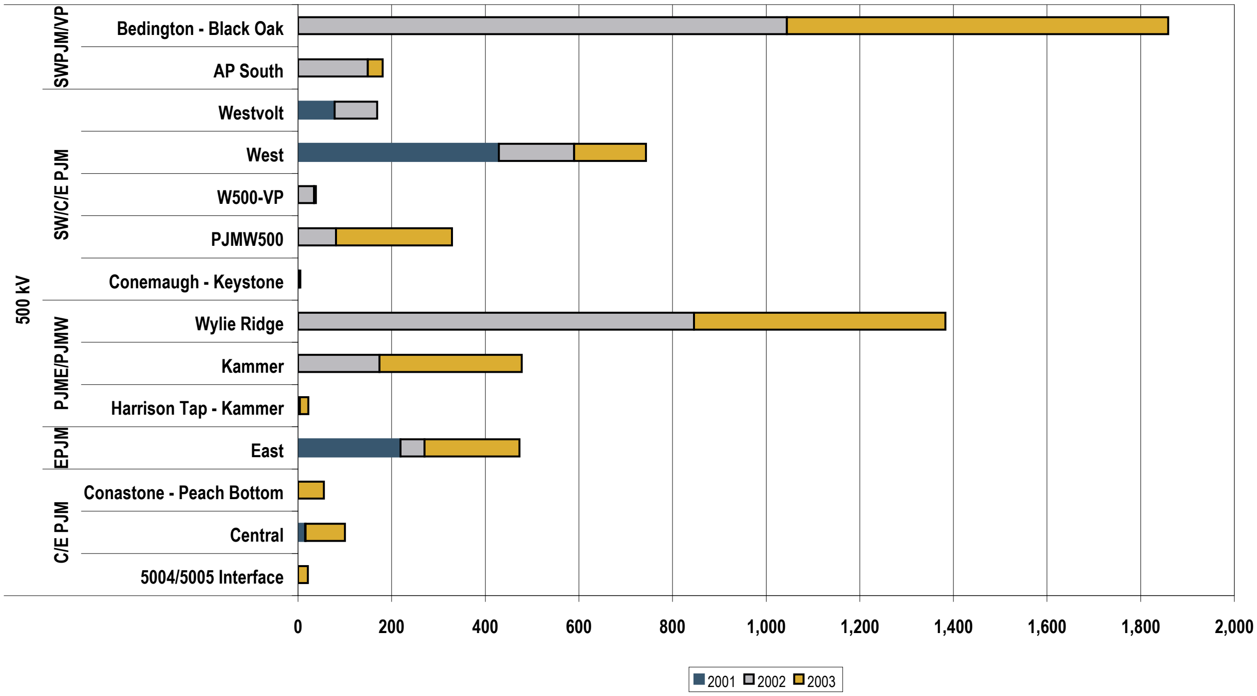
Figure 6-5 Regional Constraints: Sum of Congestion-Event Hours by Facility



Congestion-Event Hours for the 500 kV System

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

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



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

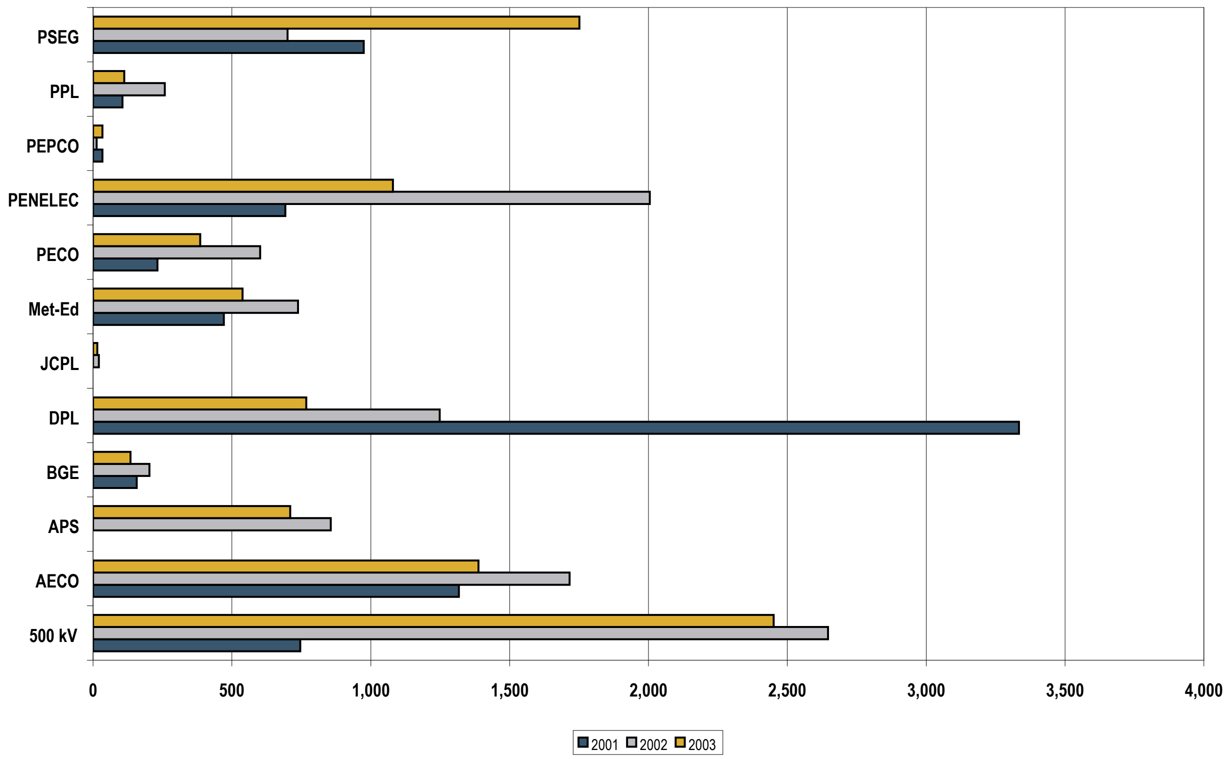
The APS extra-high-voltage (EHV) system is the primary conduit for energy transfers from APS and Midwestern generating resources to southwestern PJM and eastern Virginia load, and, to a lesser extent, to central and eastern PJM. The two APS reactive interface constraints of interest, Bedington-Black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

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

Local Congestion

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

Figure 6-7 Constrained Hours by Zone



Zonal and Subarea Congestion-Event Hours

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

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

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

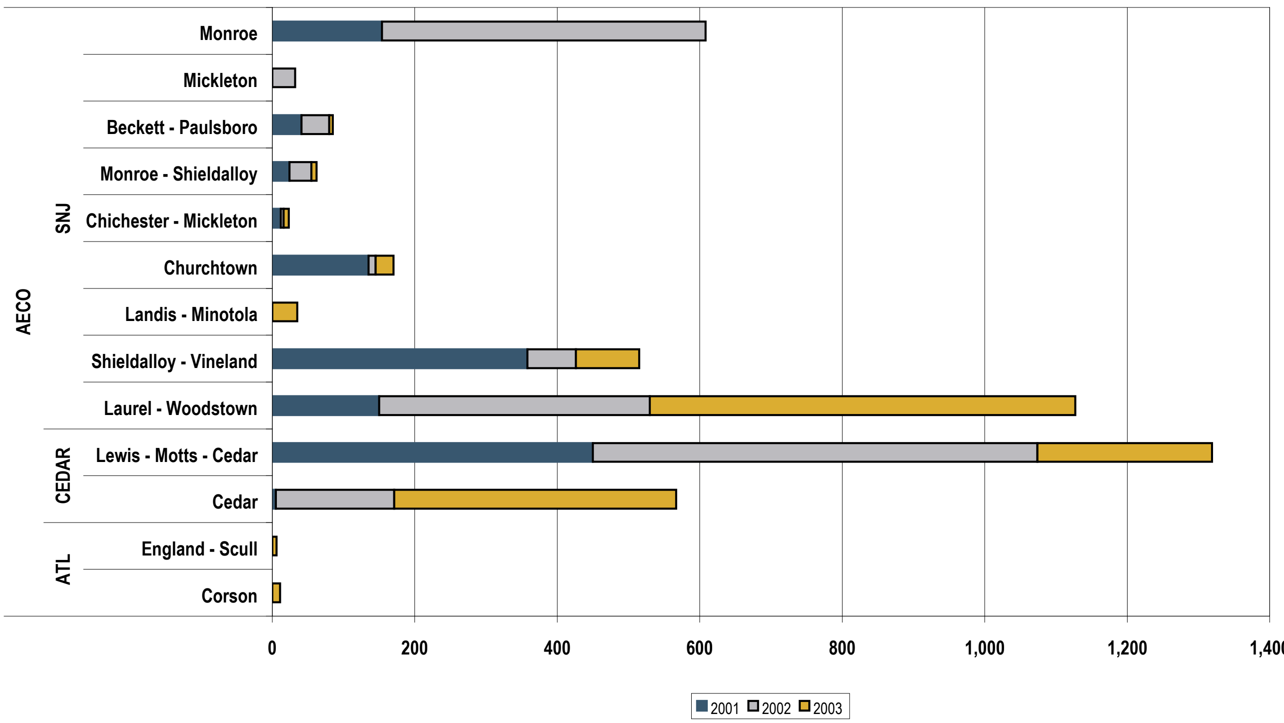


Figure 6-9 illustrates the APS zone constraints. The Doubs 500/230 kV and Wylie Ridge transformers were the most significant constraints. These facilities together represented 9 percent of all congestion-event hours in 2003. The Doubs transformer, affecting approximately 10 percent of PEPCO and APS zonal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

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

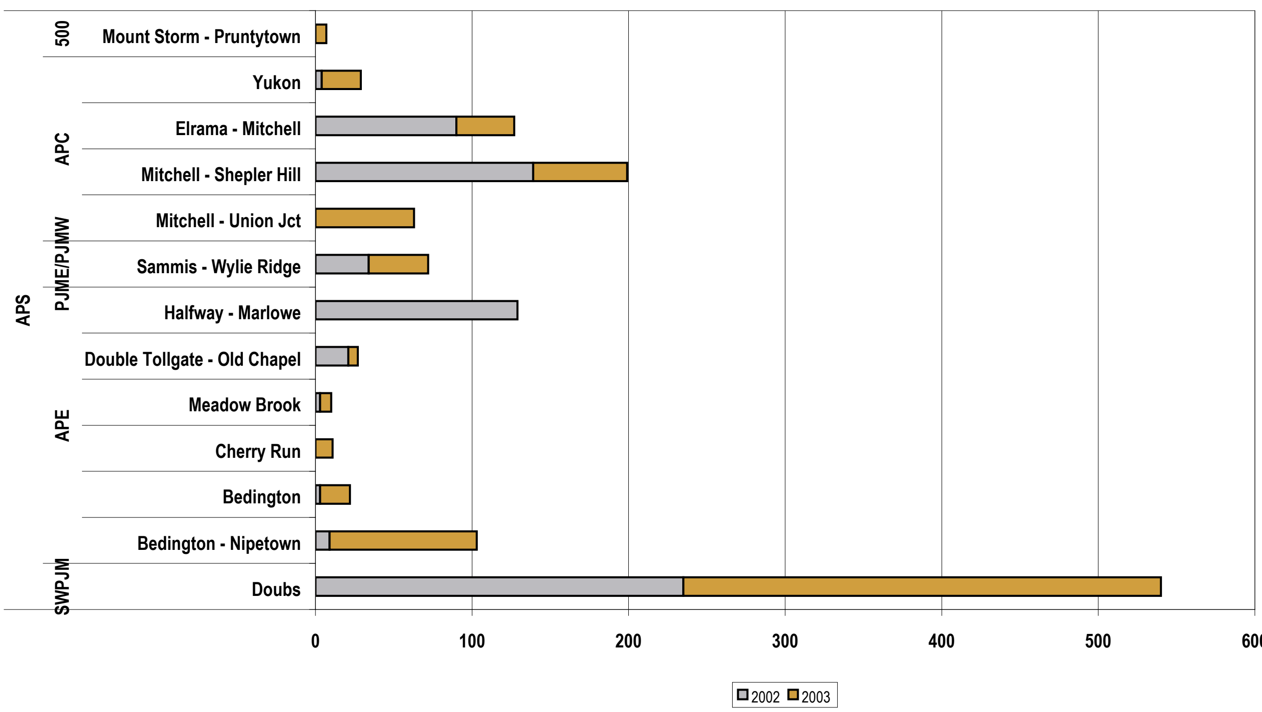


Figure 6-10 illustrates BGE zone constraints. With 142 congestion-event hours, BGE comprised only 1 percent of the total PJM congestion-event hours in 2003. One facility, the Brandon Shores-Riverside 230 kV line, was significantly constrained during 2003. This single facility accounted for 82 percent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

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

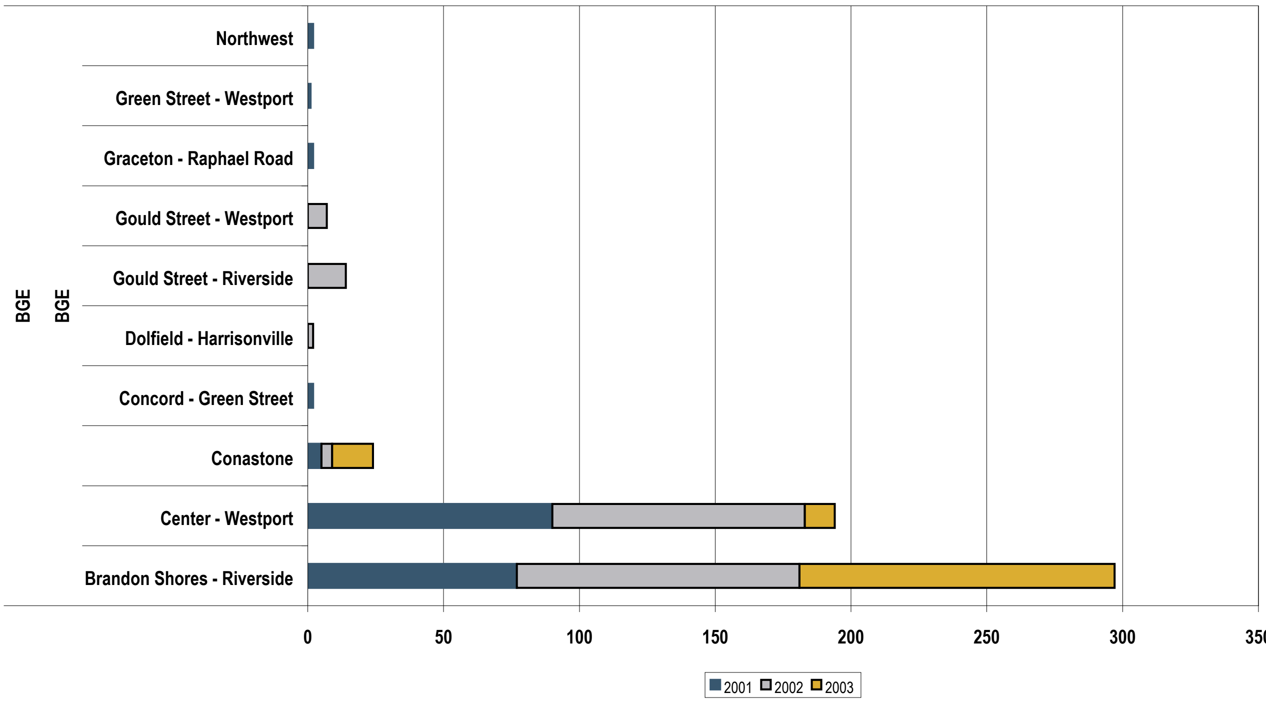


Figure 6-11 illustrates DPL zone constraint occurrences. It shows that the Delmarva Peninsula (DPLS) has experienced numerous constraints over the past three years, but their frequency has declined steadily. The 2003 decline can be directly attributed to the investments in transmission improvements and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

Figure 6-11 DPL Zone: Constrained Hours by Subarea

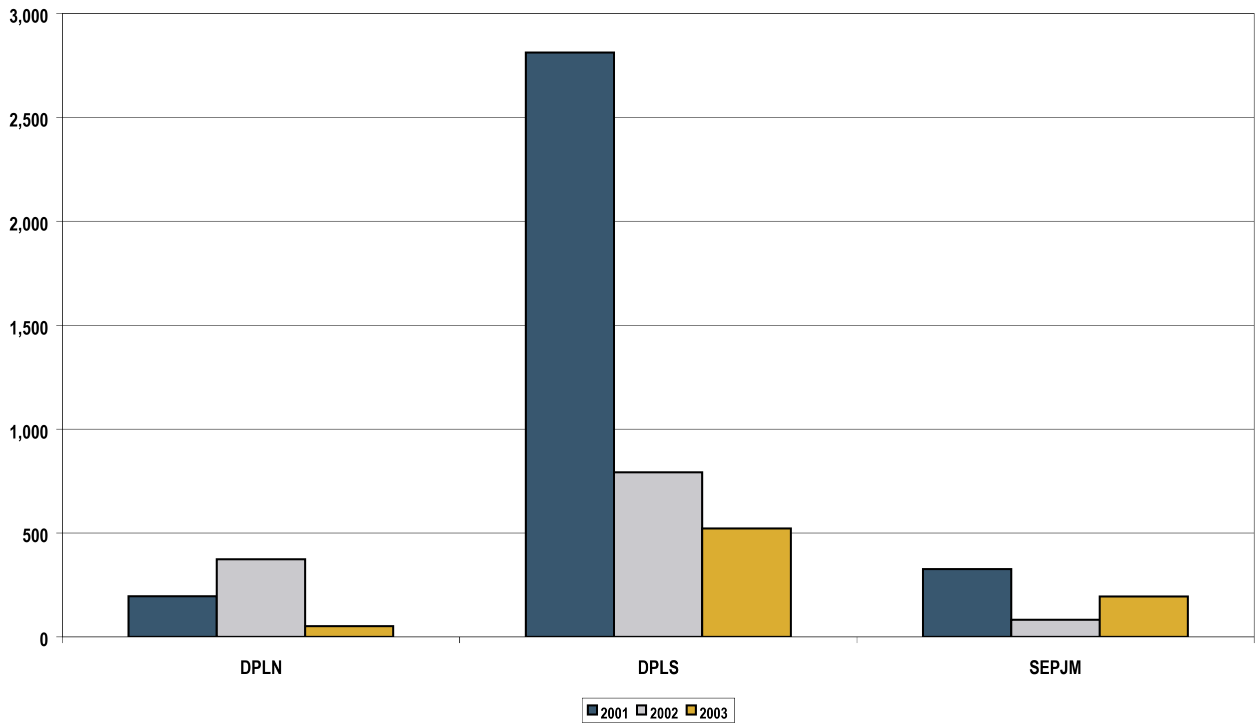


Figure 6-12 illustrates DPLS congestion-event hours by facility. Hallwood-Oak Hall 69 kV and Cheswold 138/69 kV transformer were each constrained over 250 hours in 2002, but were constrained only six and 77 hours respectively in 2003. The reduction at Cheswold is largely attributable to the upgrade of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

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

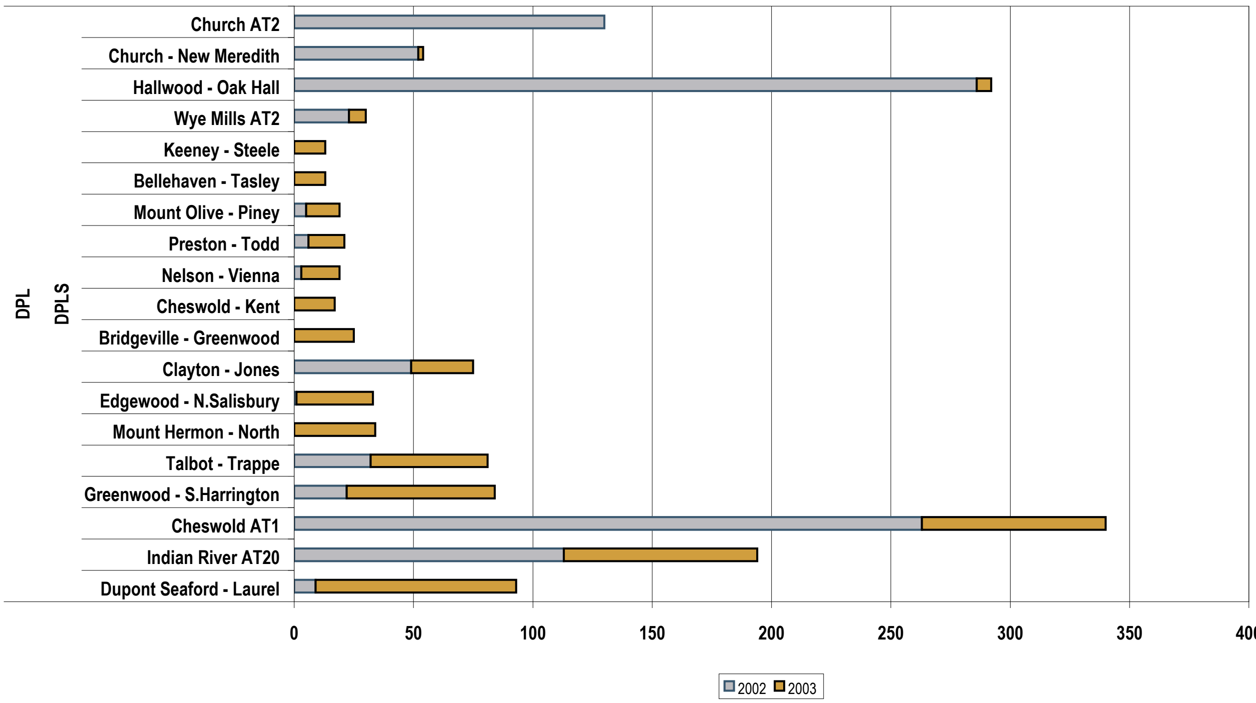
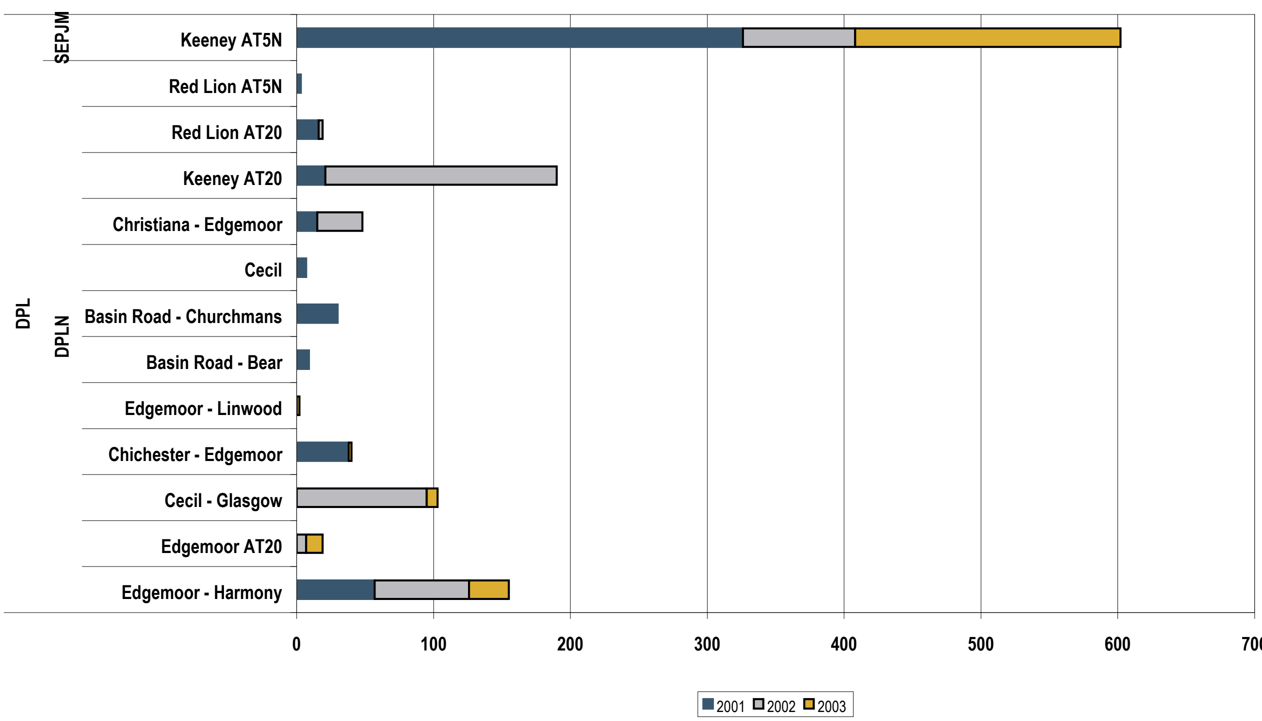


Figure 6-13 presents the same information for the DPLN and southeast PJM (SEPJM) subareas. As shown, during 2002 Keeney 230/138 kV transformer (Keeney AT20) was the most constrained facility in DPLN, with 169 congestion-event hours. The Keeney 230/138 kV transformer was replaced during 2003 and, as a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

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



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

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

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

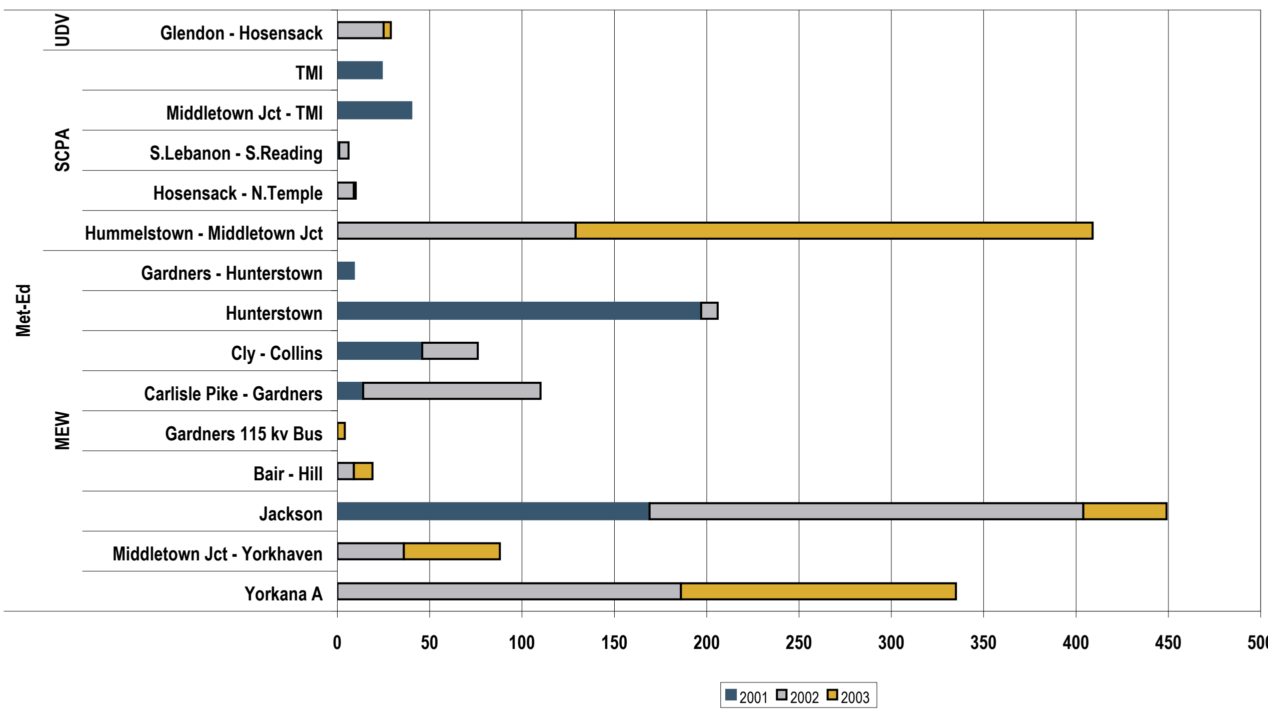


Figure 6-15 illustrates constraints in the PECO zone where in 2003 no facilities were constrained more than 100 hours. The Cromby-Moser 69 kV line, which had experienced 338 congestion-event hours in 2002, saw only 11 congestion-event hours during 2003. Reduced congestion on this facility was attributed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

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

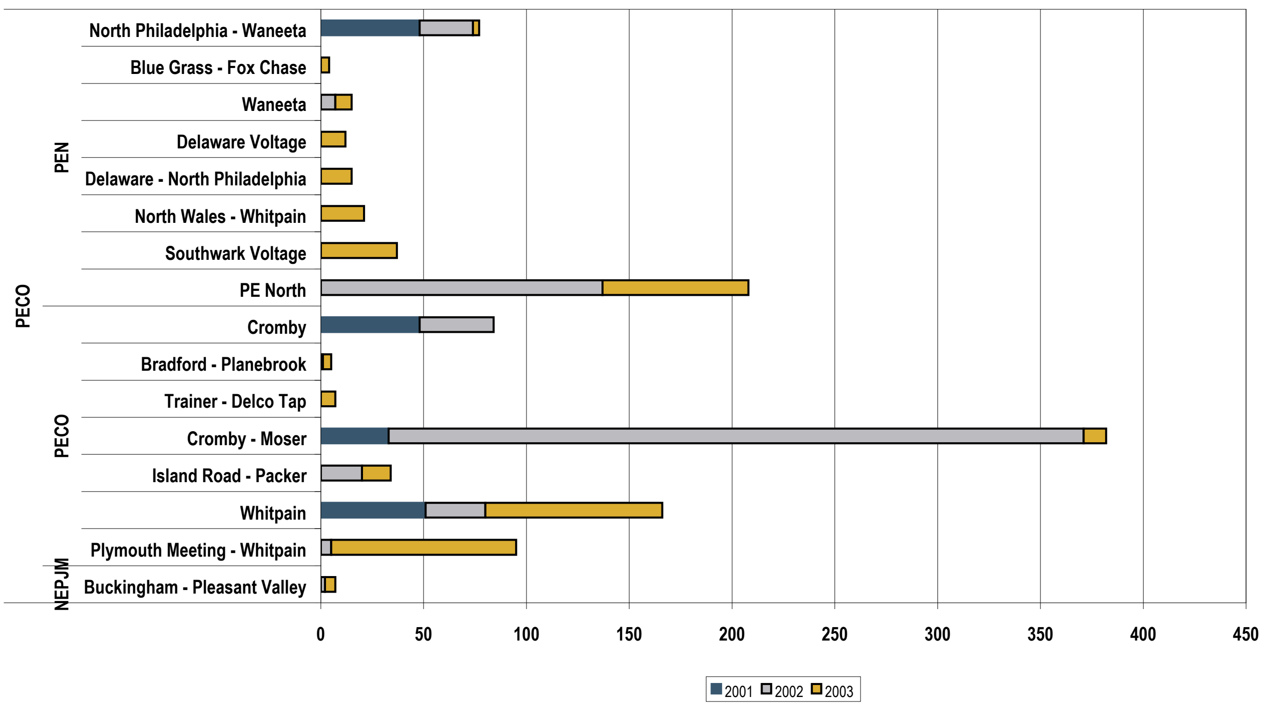
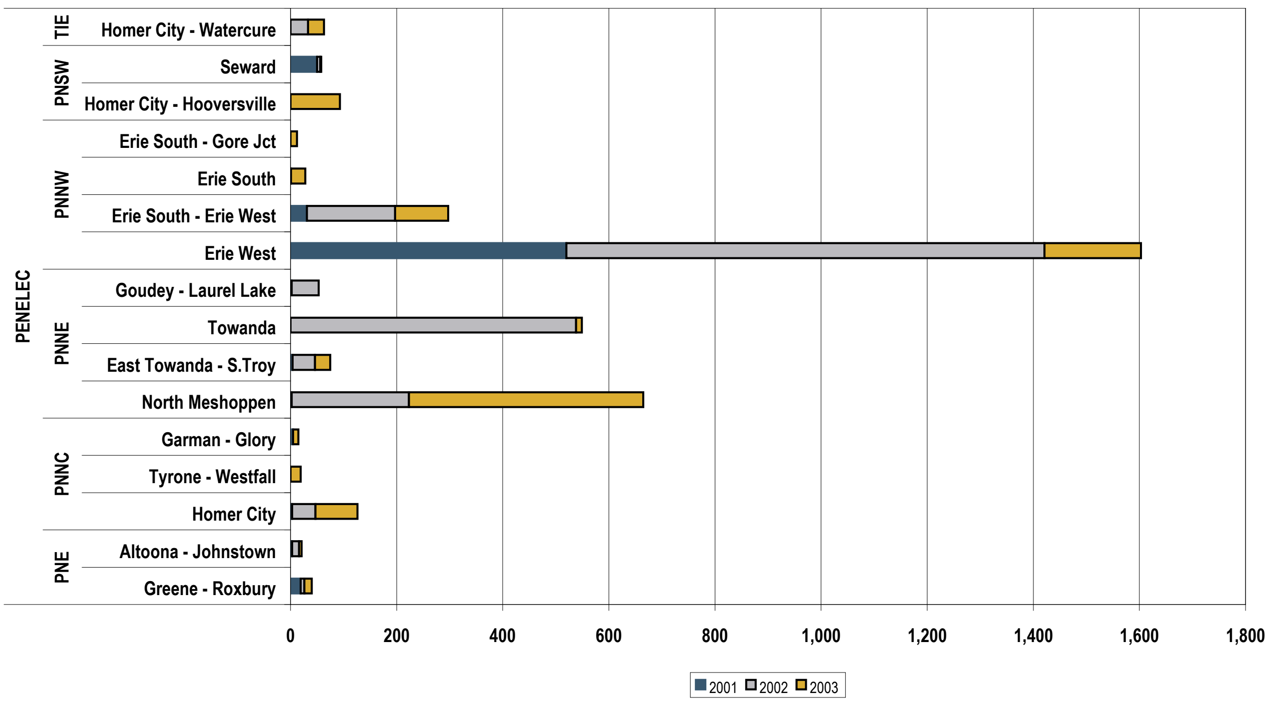


Figure 6-16 illustrates PENELEC zone constraints. It shows that constraints were considerably lower in northwestern PENELEC in 2003. In 2002, the area had experienced nearly triple the frequency in congestion-event hours, with the Erie West 230/115 transformer constrained for 901 hours. In 2003, however,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

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



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

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

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

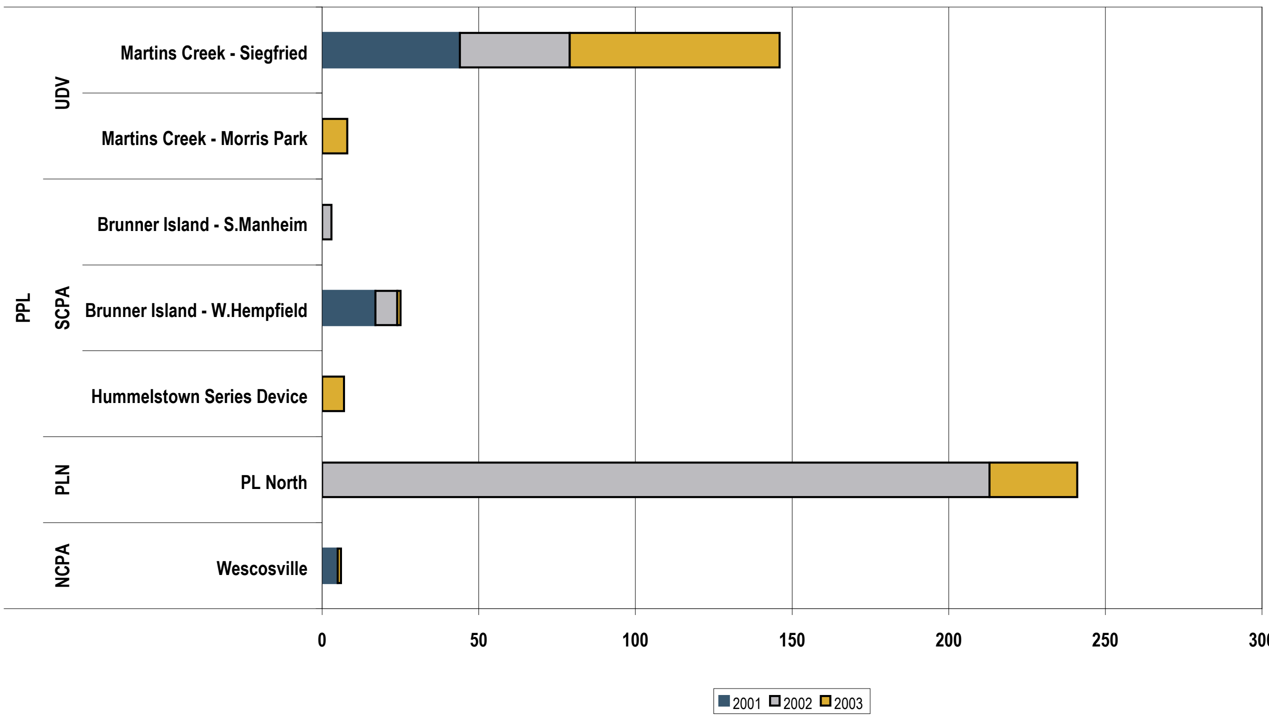


Figure 6-18 illustrates constraint occurrences in the PSEG zone. As shown, constraints in northern PSEG (PSN), primarily Cedar Grove-Roseland 230 which affects approximately one-half of PSEG zone load, were over four times as frequent in 2003 as in 2002. Congestion at Cedar Grove was caused by generation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

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

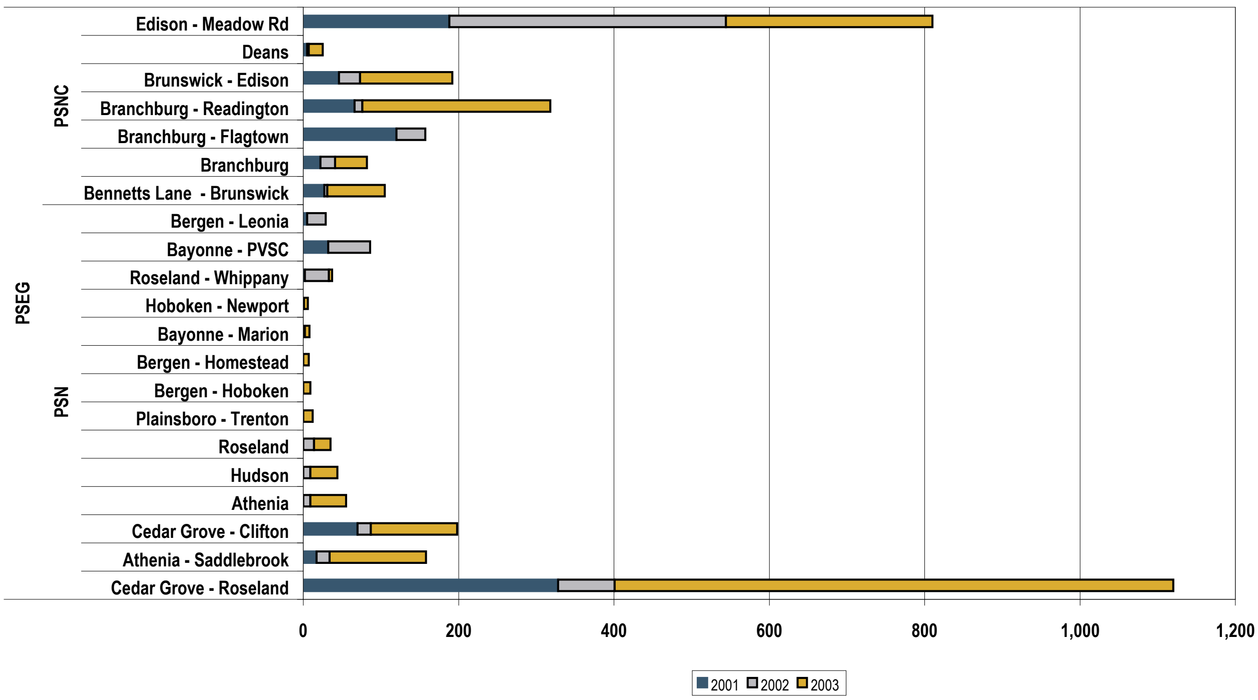


Table 6-5 lists congestion-event hours by facility type and voltage.

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

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

Congestion Management Pilot Program

The PJM Transmission Operations Manual states:

> *The PJM RTO Bulk Power Electric Supply System is operated so that loading on all PJM Monitored Bulk Power Transmission Facilities are within normal continuous ratings, and so that immediately following any single facility malfunction or failure, the loading on all remaining facilities can be expected to be within emergency ratings.*[8]

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

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

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

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

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