Section 7 – Financial Transmission and Auction Revenue Rights

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

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

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

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

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

Overview

Market Structure

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

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

Market Performance

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

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

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

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

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

Auction Revenue Rights

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

The ARR Approach

Evolution of the Annual ARR Allocation Process

The 2003/2004 Process

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

The 2004/2005 Process

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

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

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

Optional ARR Self-Scheduling

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

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

A market participant desiring to self-schedule must initiate the process in the first round of the Annual FTR Auction. One-fourth of the self-scheduled FTR MW will then clear in this and each of the three successive rounds. ARR holders that self-schedule ARRs as FTRs still hold the associated ARR. Self-scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives the corresponding revenue via holding the corresponding ARR and is left with the FTR as a hedge. The FTR hedges the holder against actual day-ahead market congestion whereas the ARR hedges the holder against congestion through revenues received based on the market value of the FTR.

ARR Target Allocations and Credits

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

Automatic ARR Reassignment for Retail Load Switching

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

Initial ARR Results

Market Structure

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

Market Performance

Volume

Allocated ARRs

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

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

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

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

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

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

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

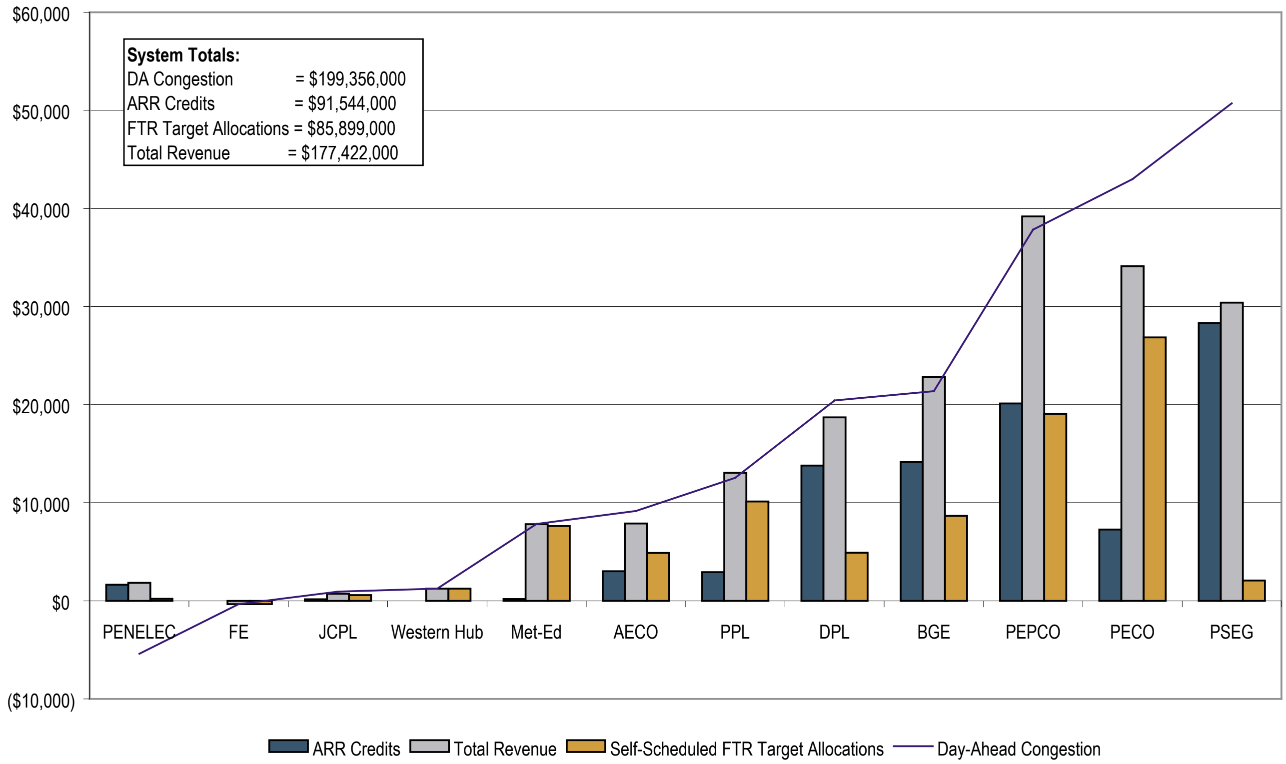


Table 7-1 also presents the extent to which each transmission zone and interface sinks were hedged as a percentage. Most were hedged above 85 percent, with the exceptions of the PSEG (60 percent), PECO (79 percent) and JCPL (78 percent) zones.[2]

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

Self-Scheduling

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

Reassigned

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

Revenue Adequacy

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

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

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

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

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

Hedging Results

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

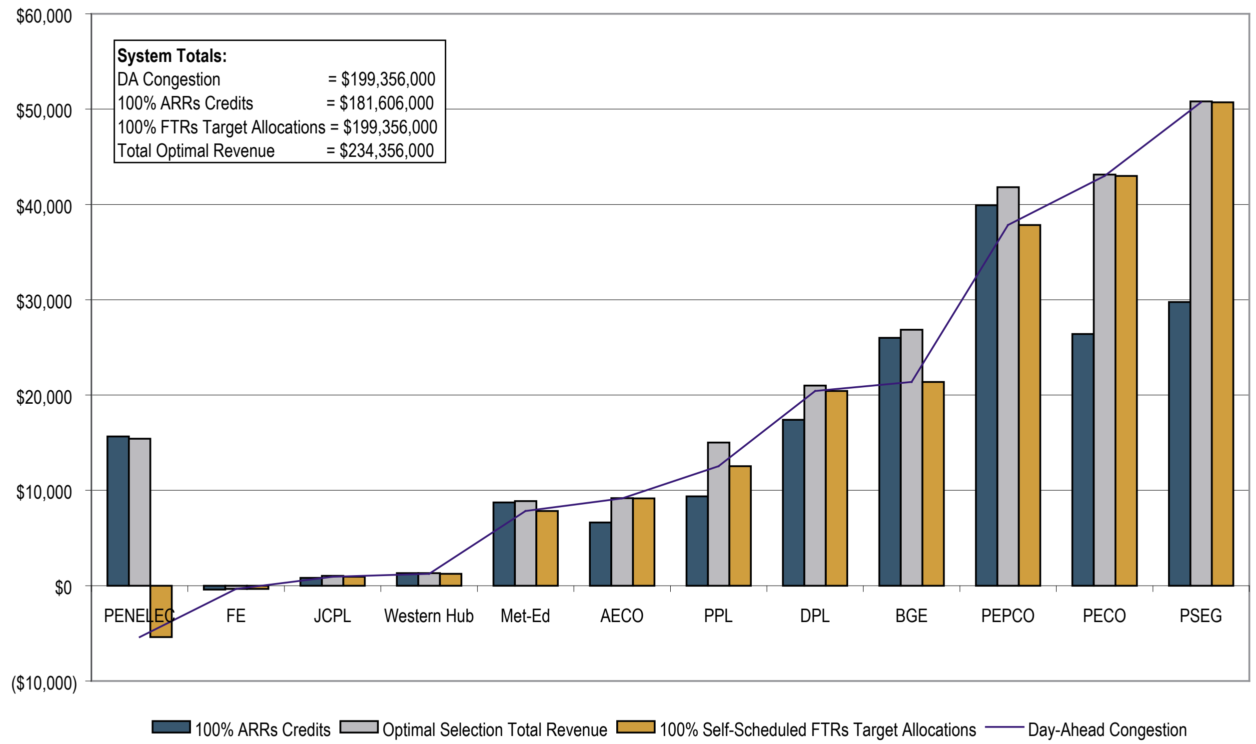
Hypothetical Hedging Strategies

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

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

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

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



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

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

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

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

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

Financial Transmission Rights

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

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

Market Structure

Before the Annual FTR Auction, only network service and long-term, firm, point-to-point transmission service customers were able to obtain annual FTRs. Now all market participants can participate in the Annual FTR Auction. Furthermore, auction market participants are free to request long-term FTRs between any pricing nodes on the system, not just from designated capacity resources to network load or solely along a long-term, firm, point-to-point transmission service path. As a result, the universe of FTRs available in the Annual FTR Auction has expanded.

FTR Auctions

Annual FTRs are allocated in a four-round auction:

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

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

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

Annual FTR Auction Results

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

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

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

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

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

Table 7-5 Mean FTRs by Term

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

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

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

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

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

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

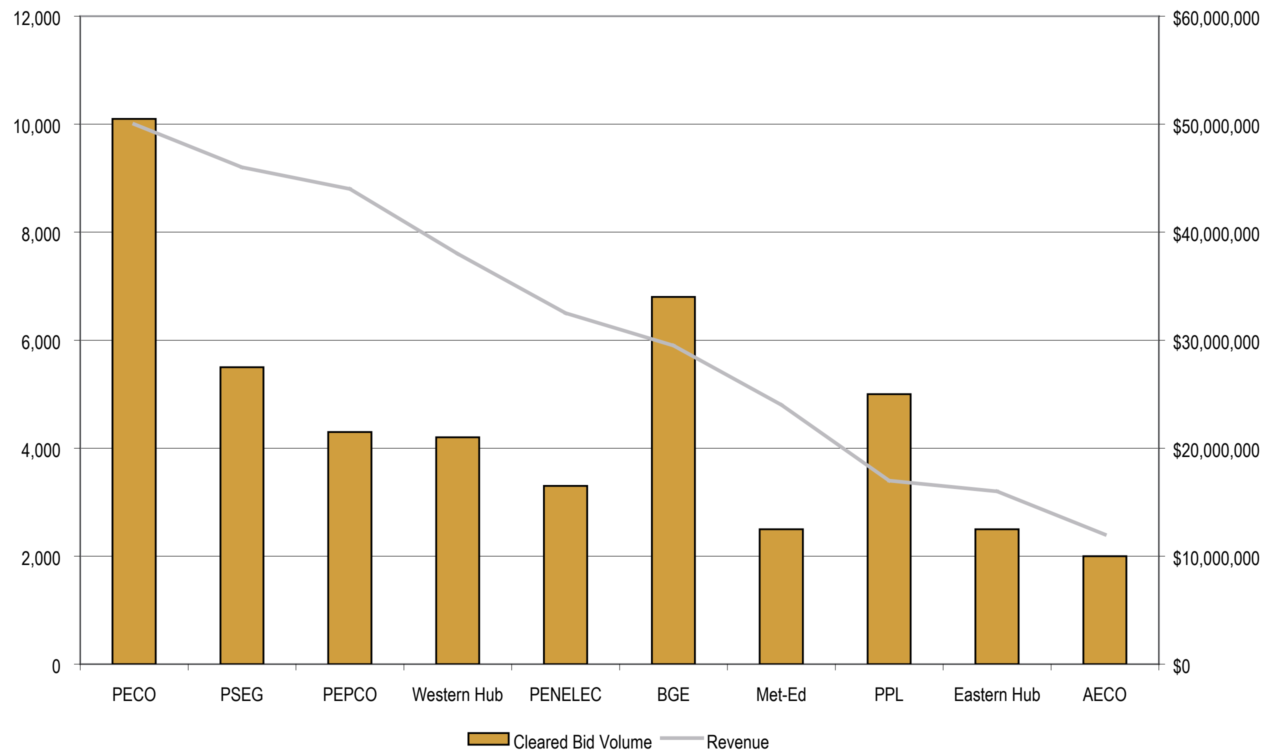
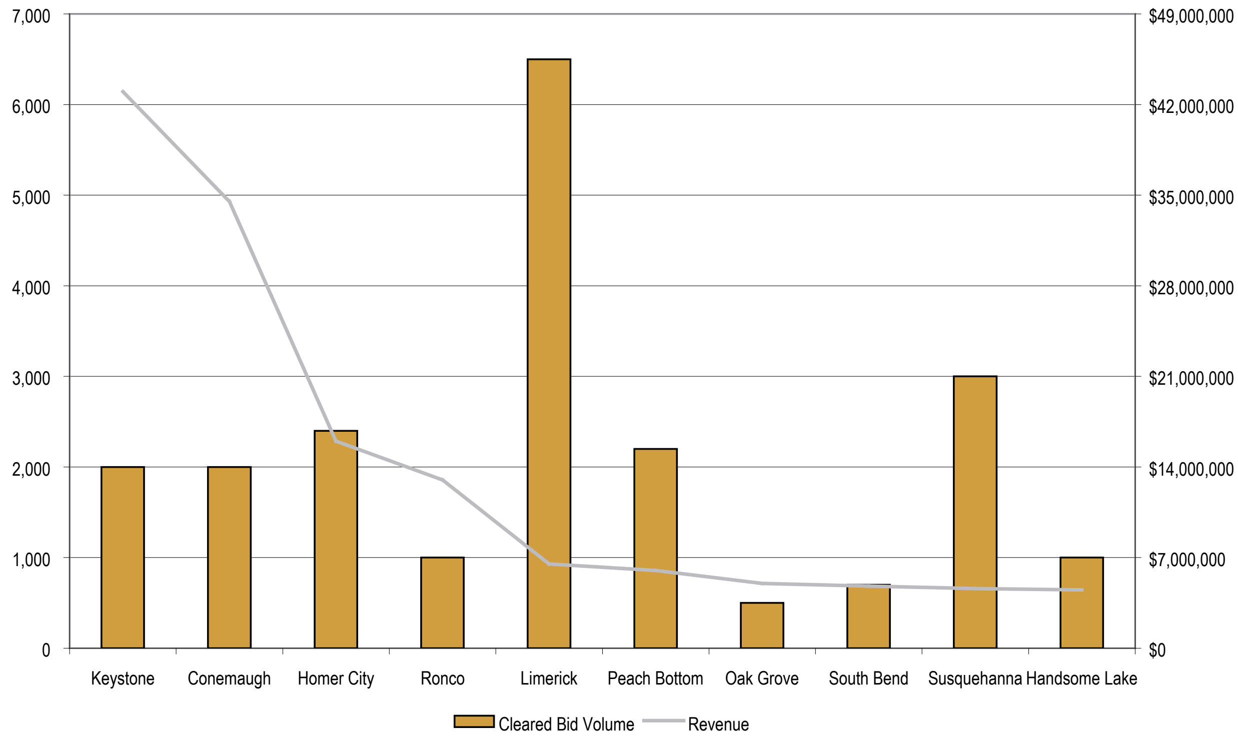


Figure 7-4 shows the 10 FTRs generating the greatest amount of annual auction revenue grouped by the FTR origin (source). FTRs from these sources accounted for $138 million or 40 percent of all revenue paid and comprised 30 percent of all FTRs purchased in the annual auction. Keystone, Conemaugh, Homer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

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



Monthly FTR Auction Results

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

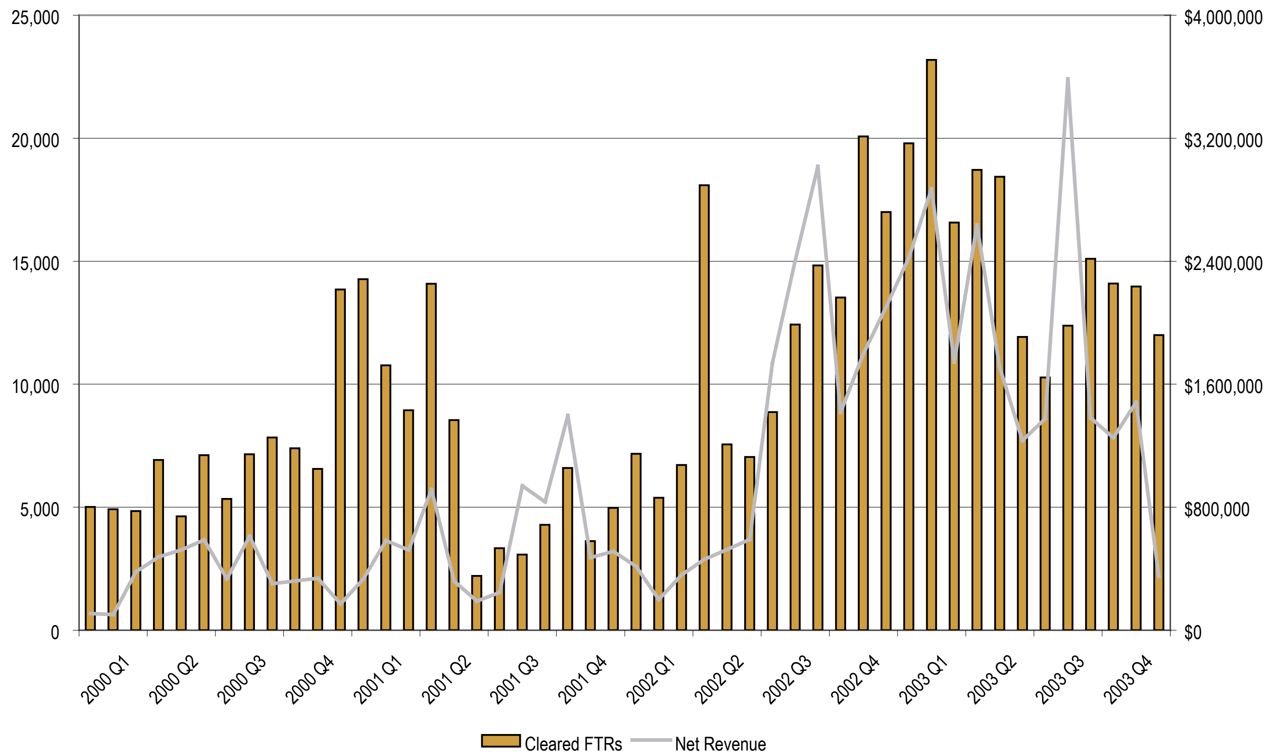
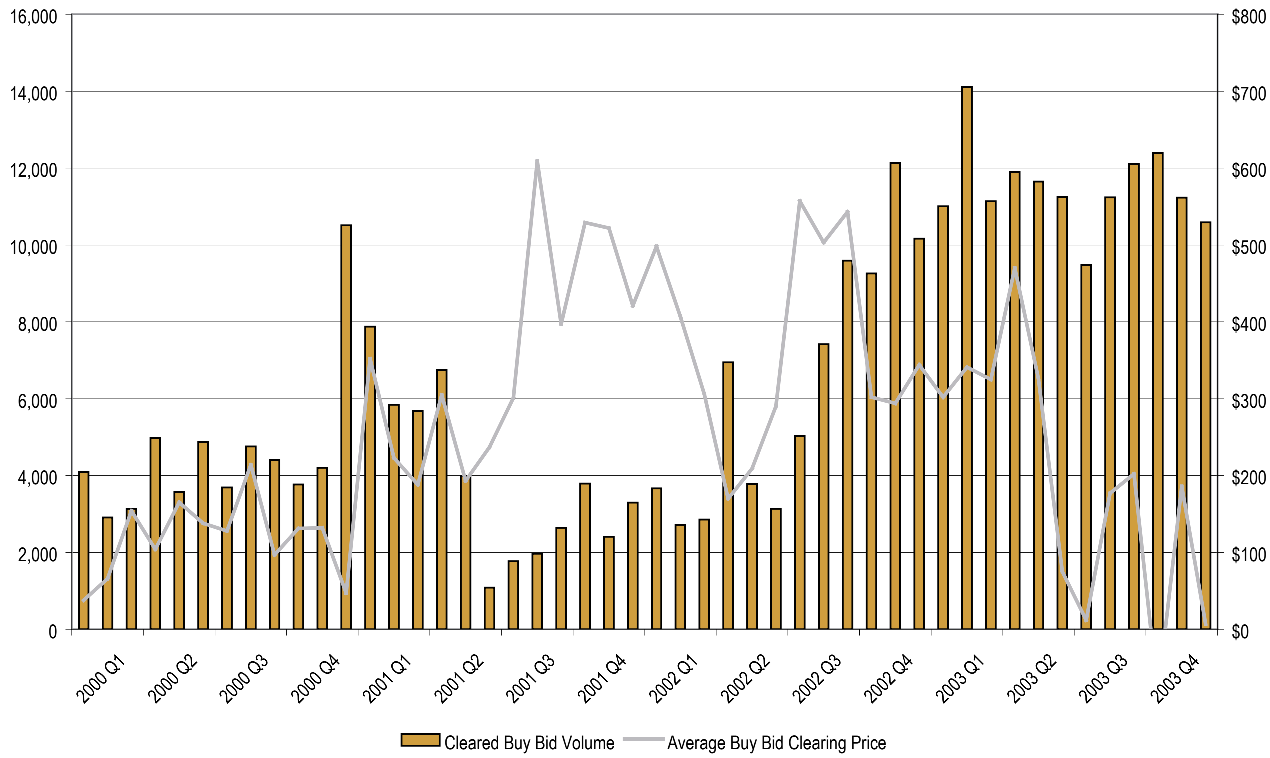


Figure 7-5 depicts the total cleared bid and offer volume together with the total auction revenue generated each month. Average monthly auction revenue grew from $350,000 per month in 2000 to over $600,000 per month in 2001, $1.2 million per month in 2002 and $1.8 million per month in 2003. The $21.6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

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



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

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

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

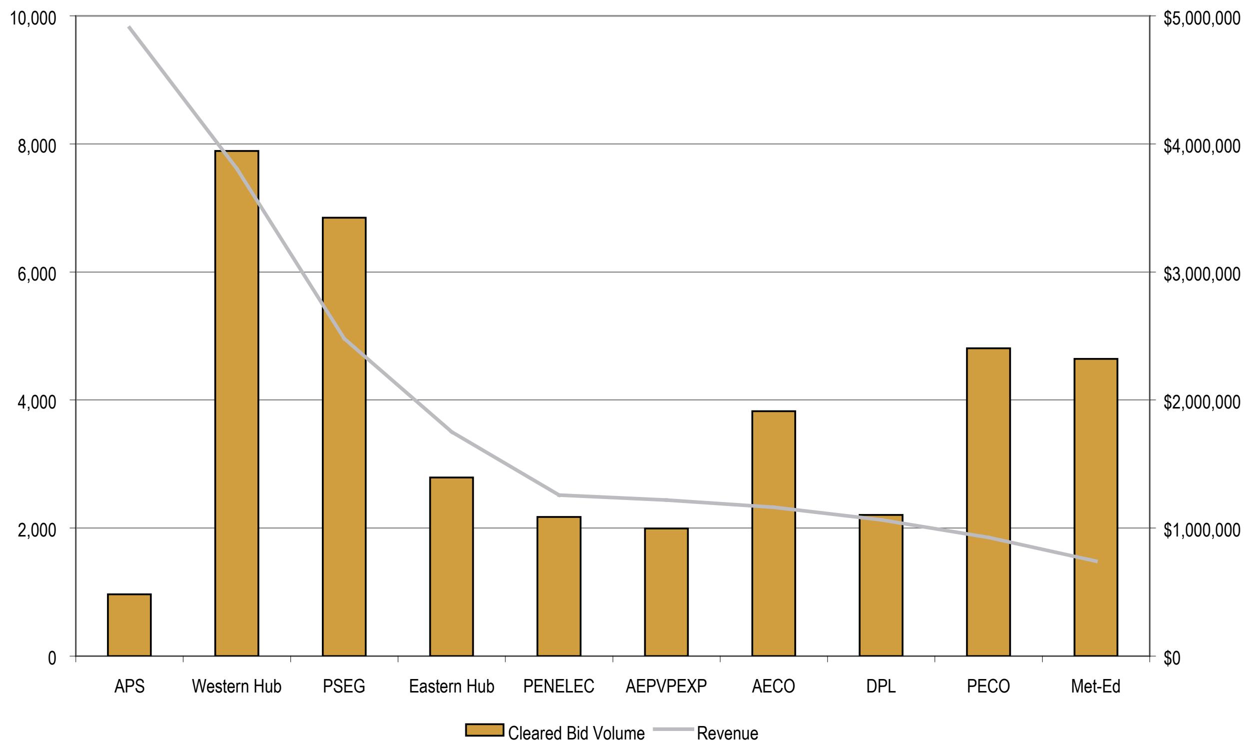
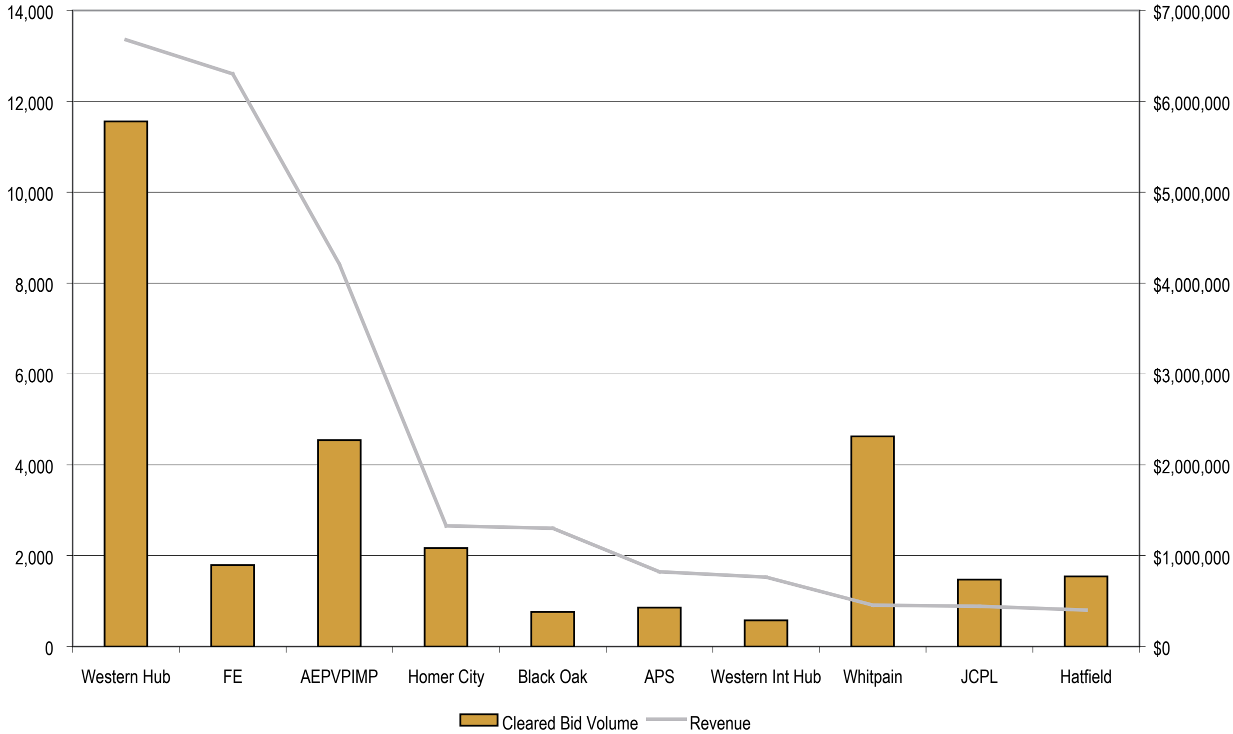


Figure 7-7 shows the 10 FTRs that generated the greatest amount of monthly auction revenue grouped by the FTR destination (sink). FTRs to these sinks accounted for $19.3 million, just under 40 percent, of all revenue paid and comprised 12 percent of all FTRs bought in Monthly FTR Auctions. These sinks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

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

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



Daily FTR Market Activity

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

FTR Revenue Adequacy

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

FTR Target Allocations

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

Ten Greatest Net FTR Target Allocations Summed by Sink and Source

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

Ten Greatest Positive FTR Target Allocations Summed by Sink and Source

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

Ten Greatest Negative FTR Target Allocations Summed by Sink and Source

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

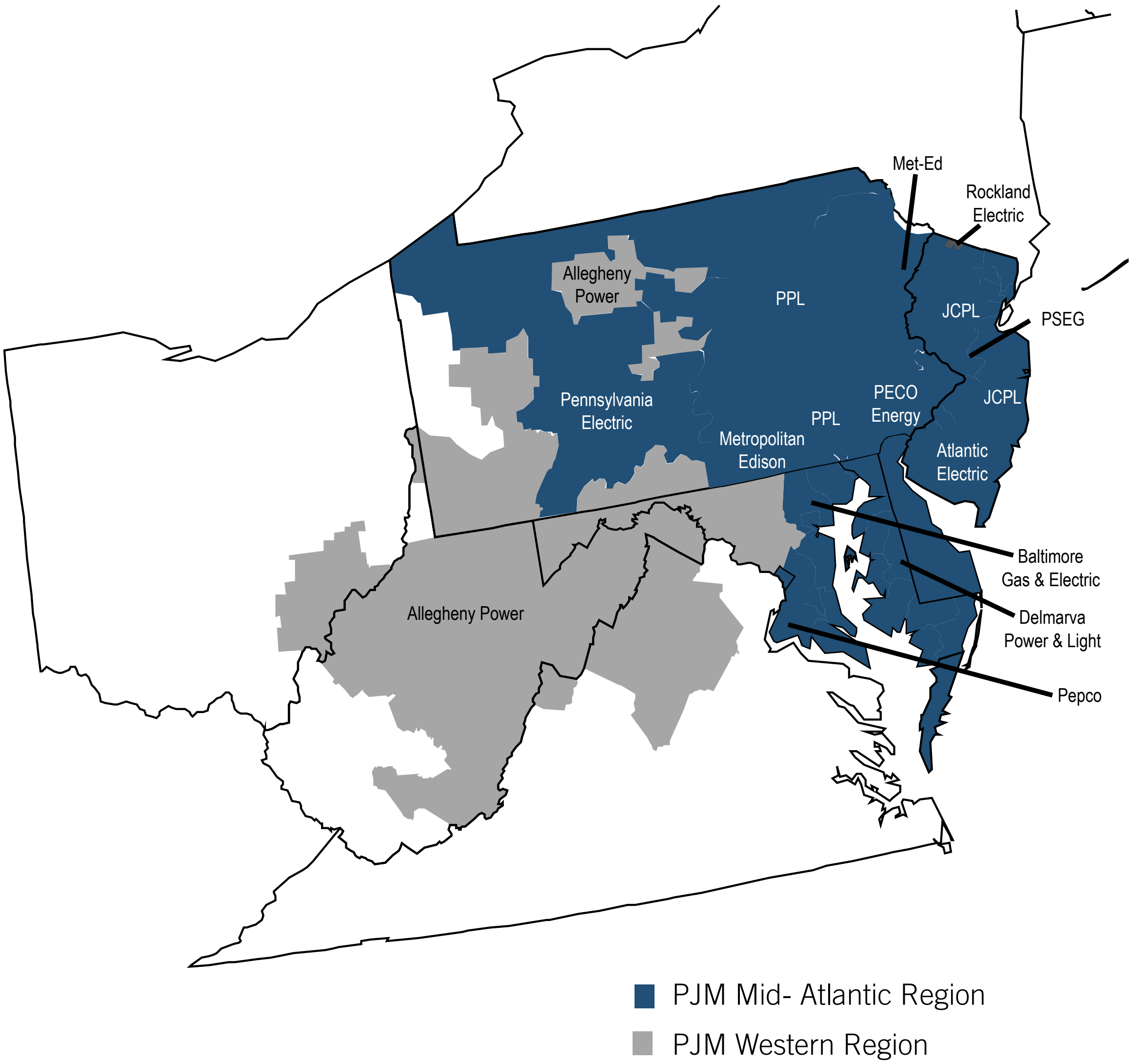
Table 7-6 itemizes the highest value net positively valued and negatively valued FTR target allocations for 2003 by sources and sinks.

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

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

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

Appendix A – PJM Service Area



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

Appendix B – PJM Market Milestones

Year	Month	Event
1996	April	FERC Order 888
1997	April	Bid-based Energy Market
	November	FERC Approval of PJM ISO status
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC Approval of Market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	April	Competitive Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load Reduction Pilot Program
2001	June	First PJM Emergency and Economic Load Response Programs
2002	April	Integration of PJM Western Region
	June	Second PJM Emergency and Economic Load Response Programs
	December	Spinning Reserve Market
	December	FERC Approval of Full PJM RTO Status
2003	May	Annual FTR Auction

Appendix C – Energy Market

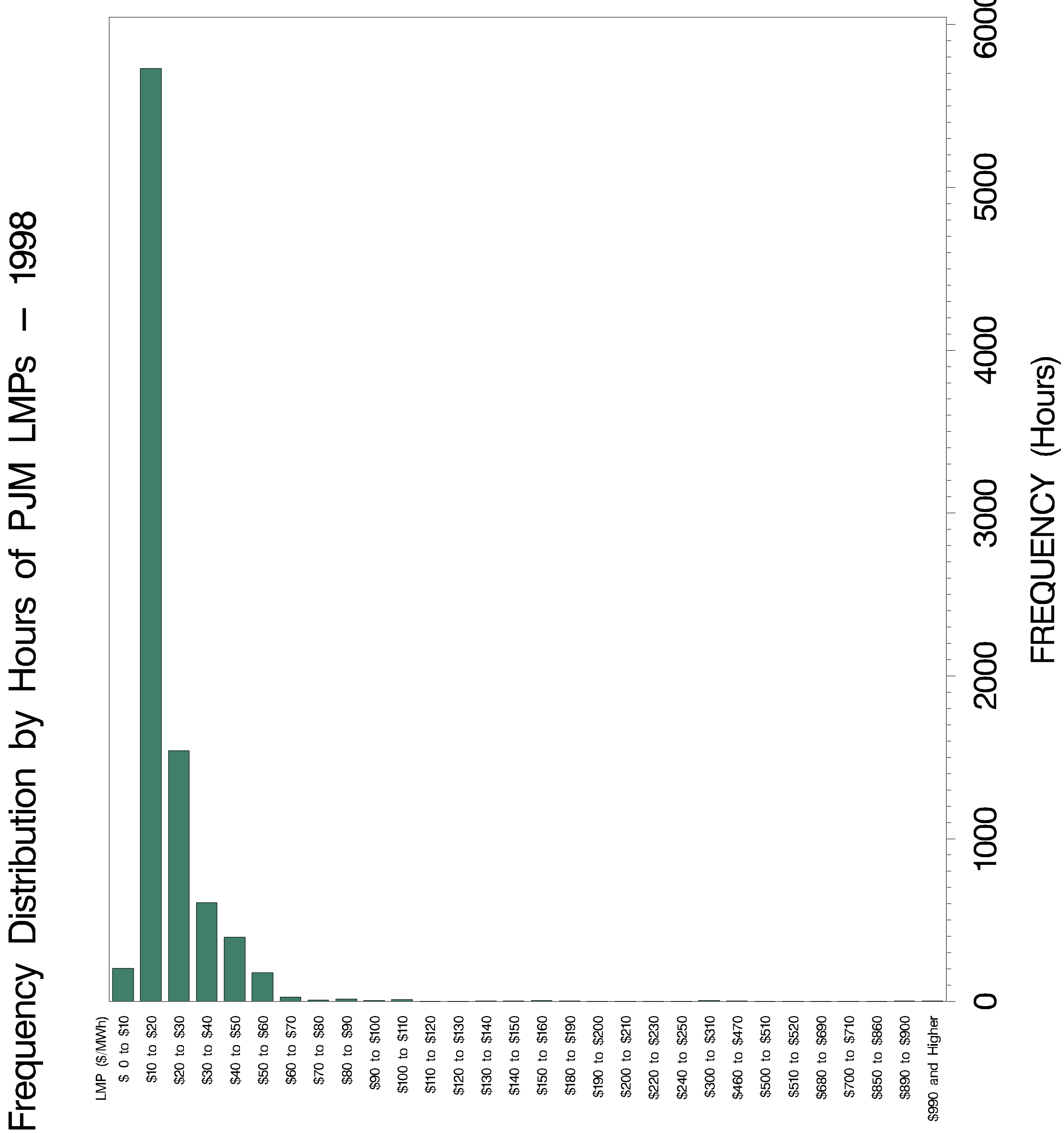
Frequency Distribution of LMP

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

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

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

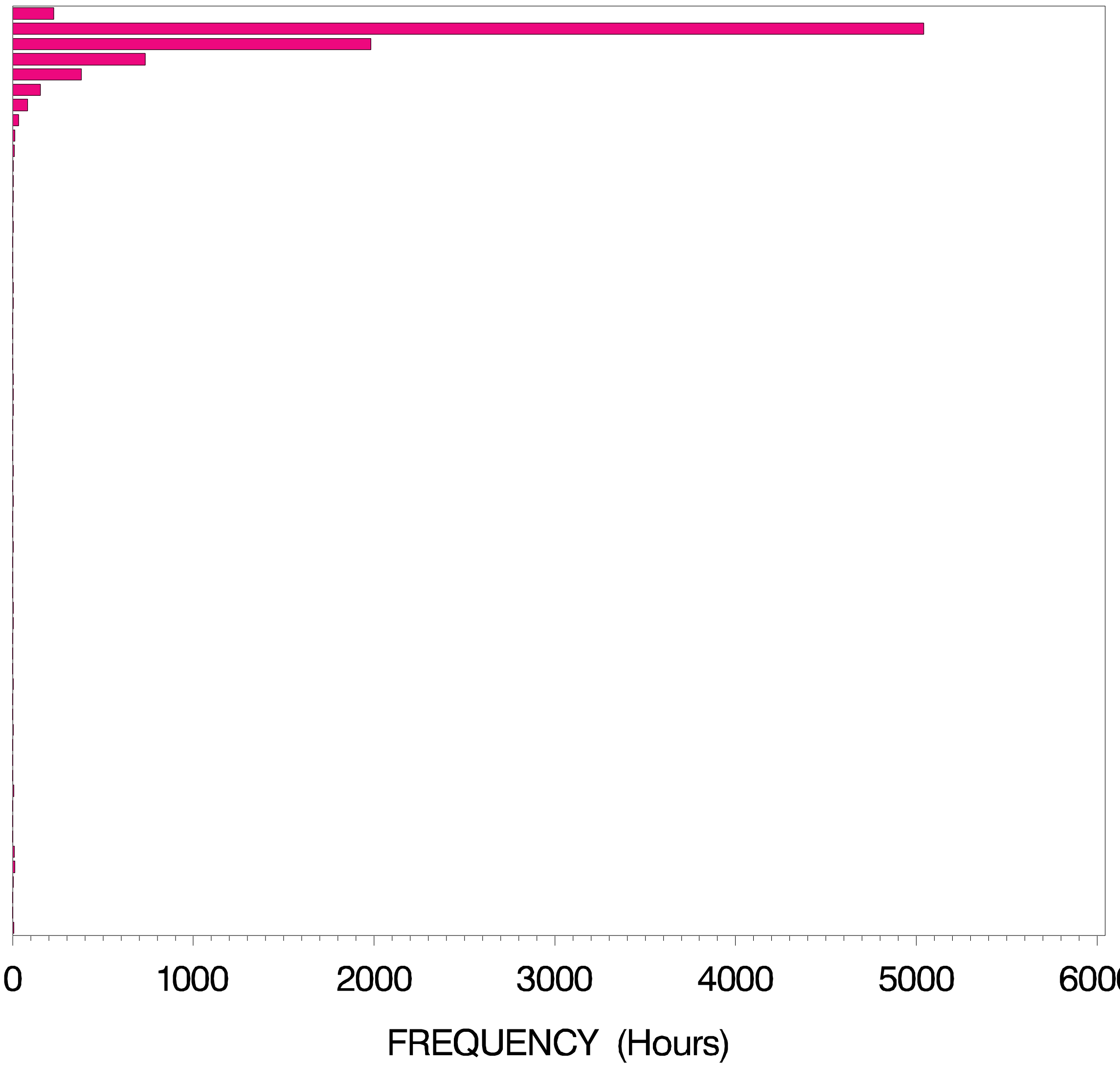
Figure C-1 Frequency Distribution by Hours of PJM LMP: 1998



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

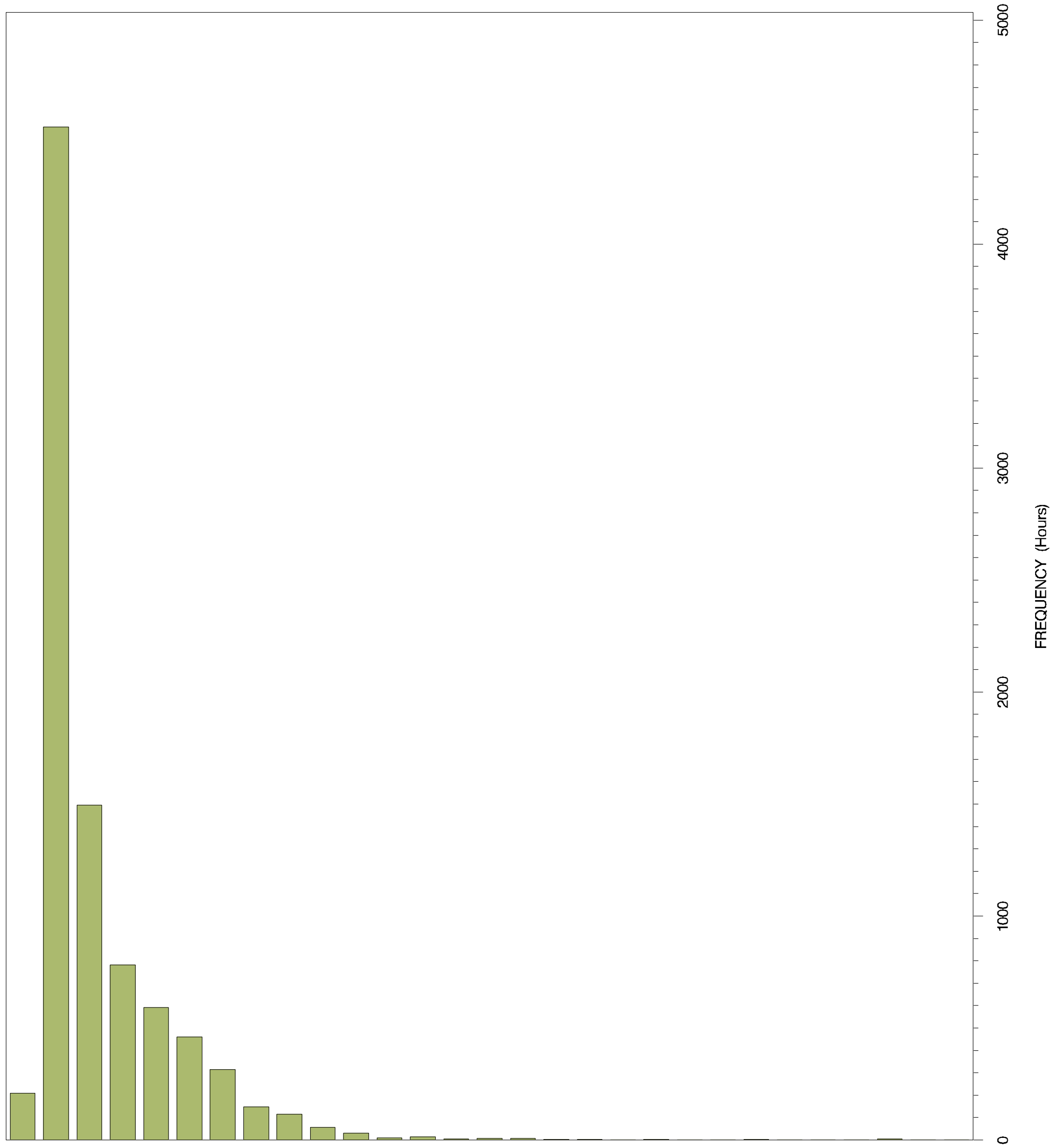
Figure C-2 Frequency Distribution by Hours of PJM LMP: 1999

Frequency Distribution by Hours of PJM LMPs – 1999



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

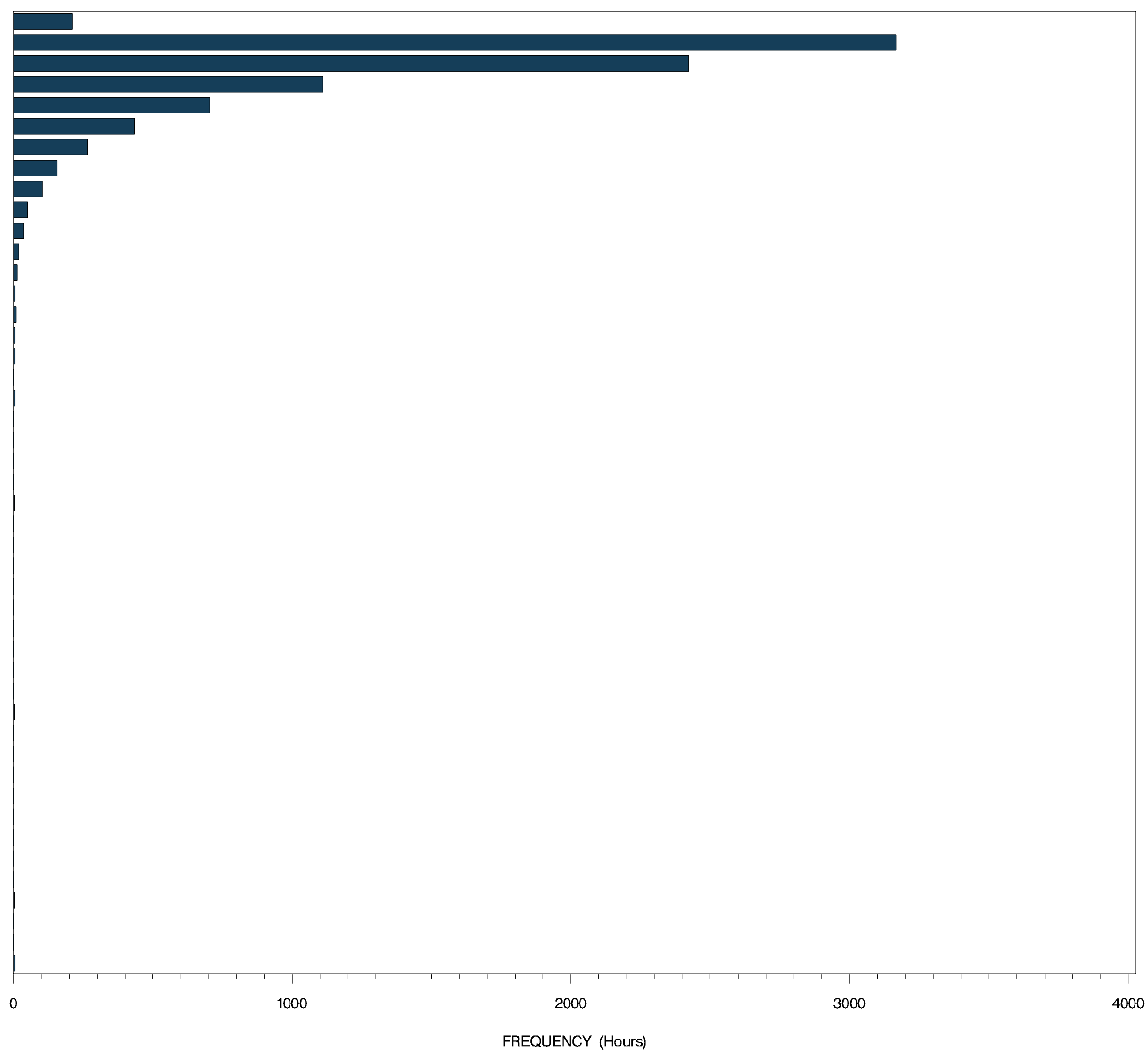
Figure C-3 Frequency Distribution by Hours of PJM LMP: 2000



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

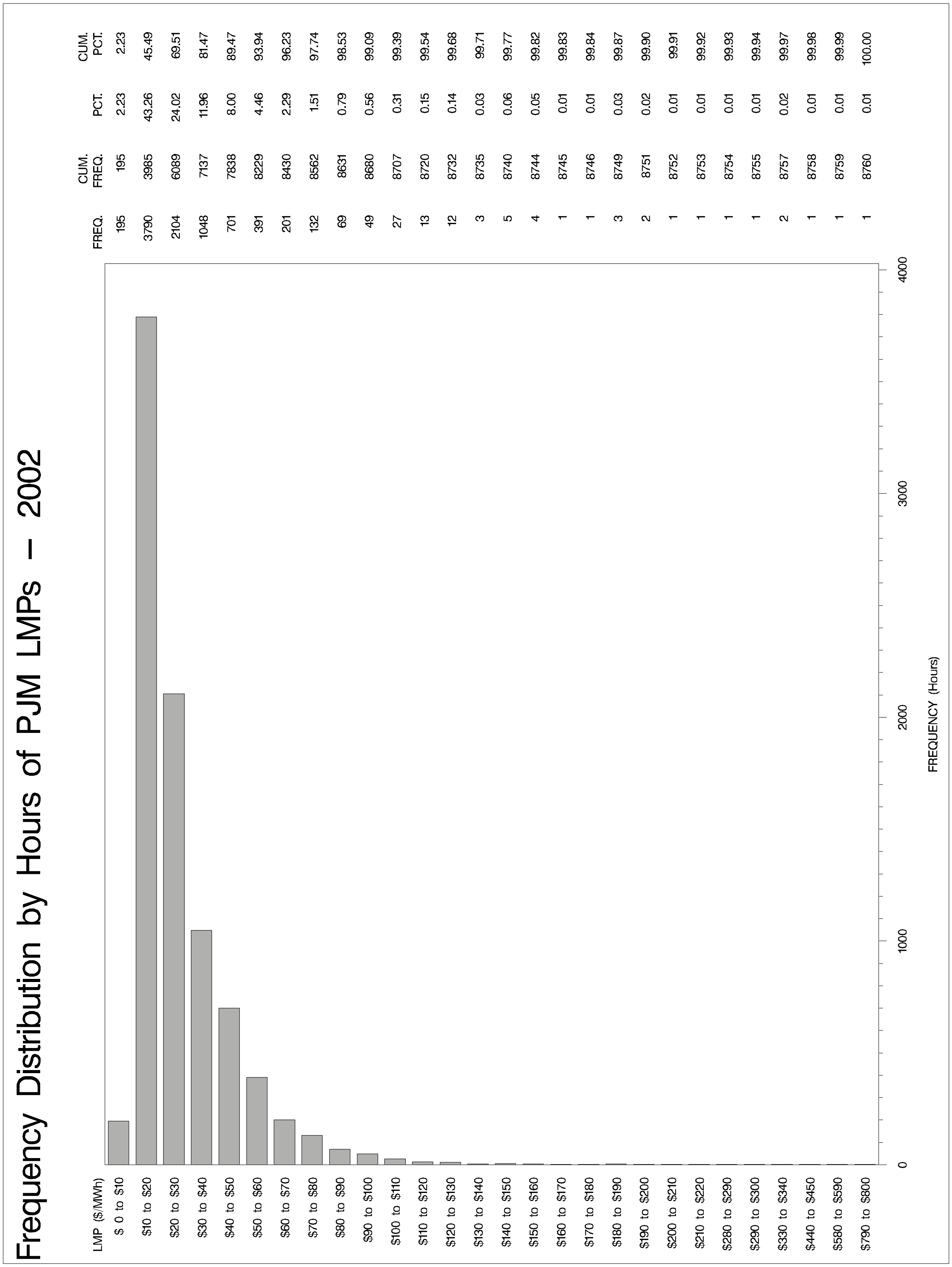
Figure C-4 Frequency Distribution by Hours of PJM LMP: 2001

Frequency Distribution by Hours of PJM LMPs – 2001



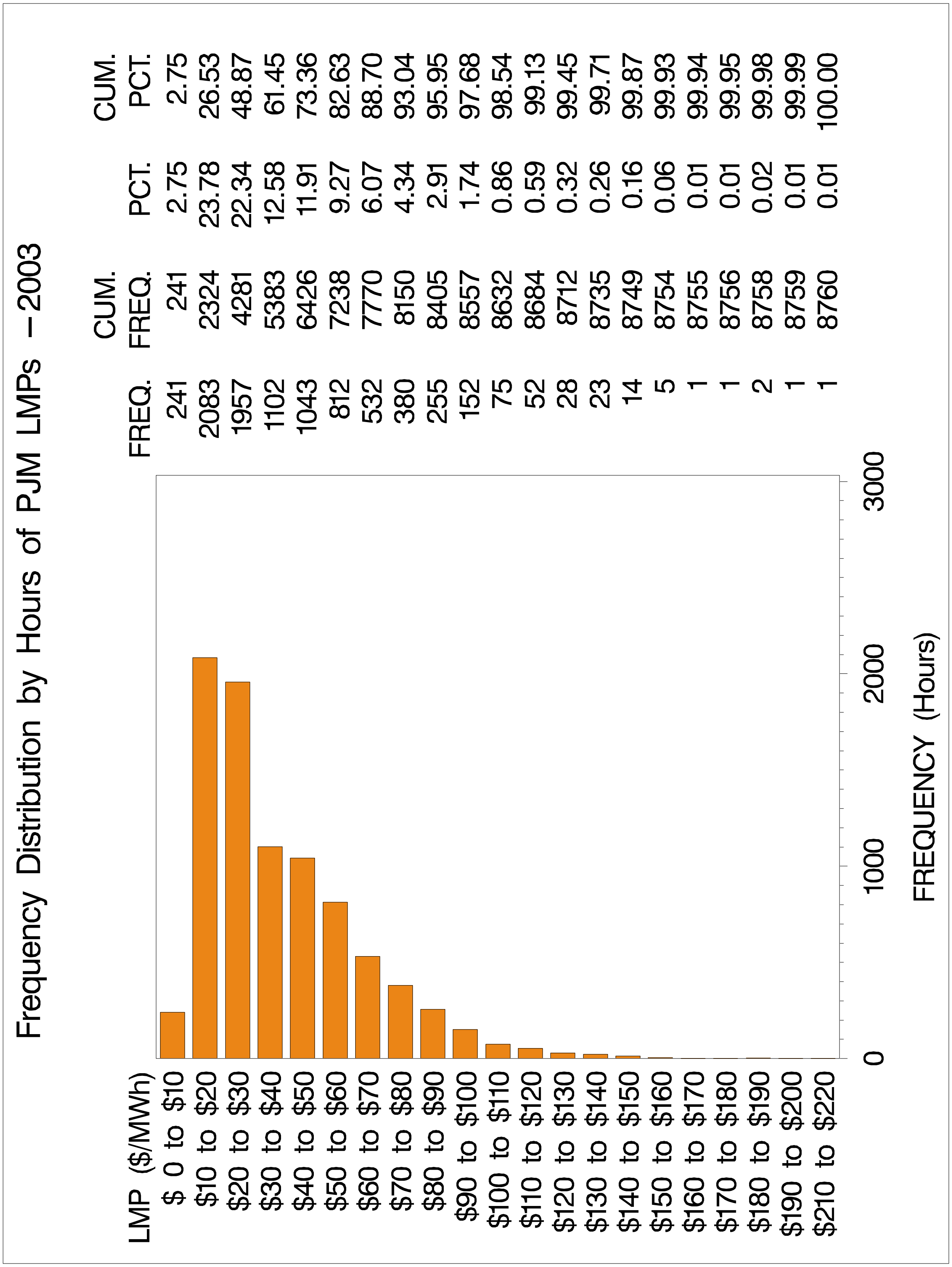
LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	210	210	2.40	2.40
$10 to $20	3167	3377	36.15	38.55
$20 to $30	2423	5800	27.66	66.21
$30 to $40	1109	6909	12.66	78.87
$40 to $50	704	7613	8.04	86.91
$50 to $60	433	8046	4.94	91.85
$60 to $70	264	8310	3.01	94.86
$70 to $80	155	8465	1.77	96.63
$80 to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

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



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	195	195	2.23	2.23
$10 to $20	3790	3985	43.26	45.49
$20 to $30	2104	6089	24.02	69.51
$30 to $40	1048	7137	11.96	81.47
$40 to $50	701	7838	8.00	89.47
$50 to $60	391	8229	4.46	93.94
$60 to $70	201	8430	2.29	96.23
$70 to $80	132	8562	1.51	97.74
$80 to $90	69	8631	0.79	98.53
$90 to $100	49	8680	0.56	99.09
$100 to $110	27	8707	0.31	99.39
$110 to $120	13	8720	0.15	99.54
$120 to $130	12	8732	0.14	99.68
$130 to $140	3	8735	0.03	99.71
$140 to $150	5	8740	0.06	99.77
$150 to $160	4	8744	0.05	99.82
$160 to $170	1	8745	0.01	99.83
$170 to $180	1	8746	0.01	99.84
$180 to $190	3	8749	0.03	99.87
$190 to $200	2	8751	0.02	99.90
$200 to $210	1	8752	0.01	99.91
$210 to $220	1	8753	0.01	99.92
$280 to $290	1	8754	0.01	99.93
$290 to $300	1	8755	0.01	99.94
$330 to $340	2	8757	0.02	99.97
$440 to $450	1	8758	0.01	99.98
$580 to $590	1	8759	0.01	99.99
$790 to $800	1	8760	0.01	100.00

Figure C-6 **Frequency Distribution by Hours of PJM LMP: 2003**



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

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

Frequency Distribution by Hourly PJM Load – 1998

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

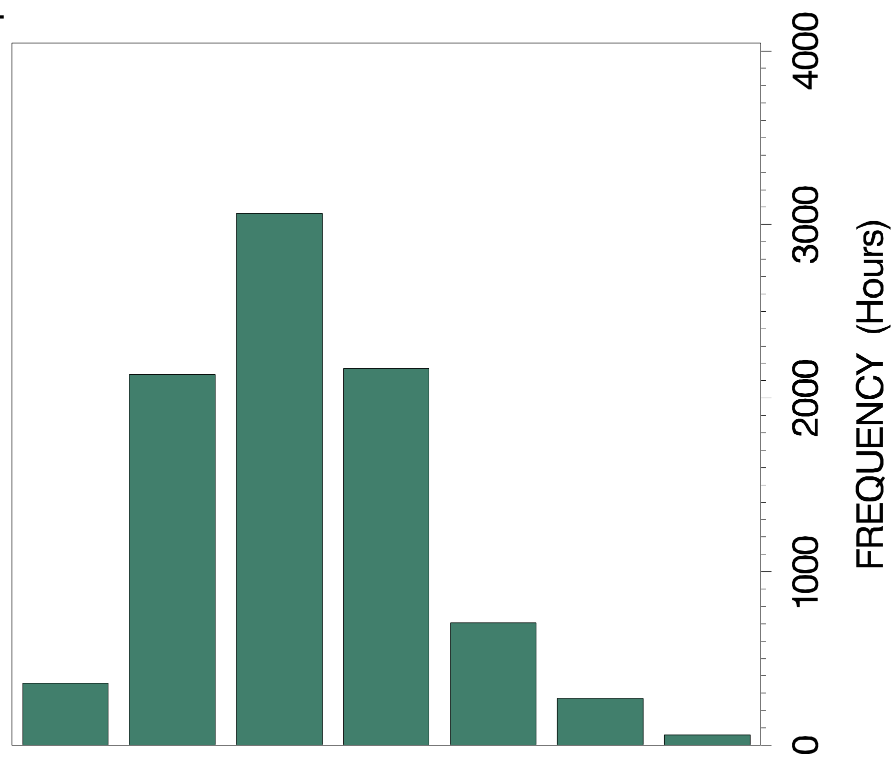


Figure C-8 Frequency Distribution of Hourly PJM Load: 1999

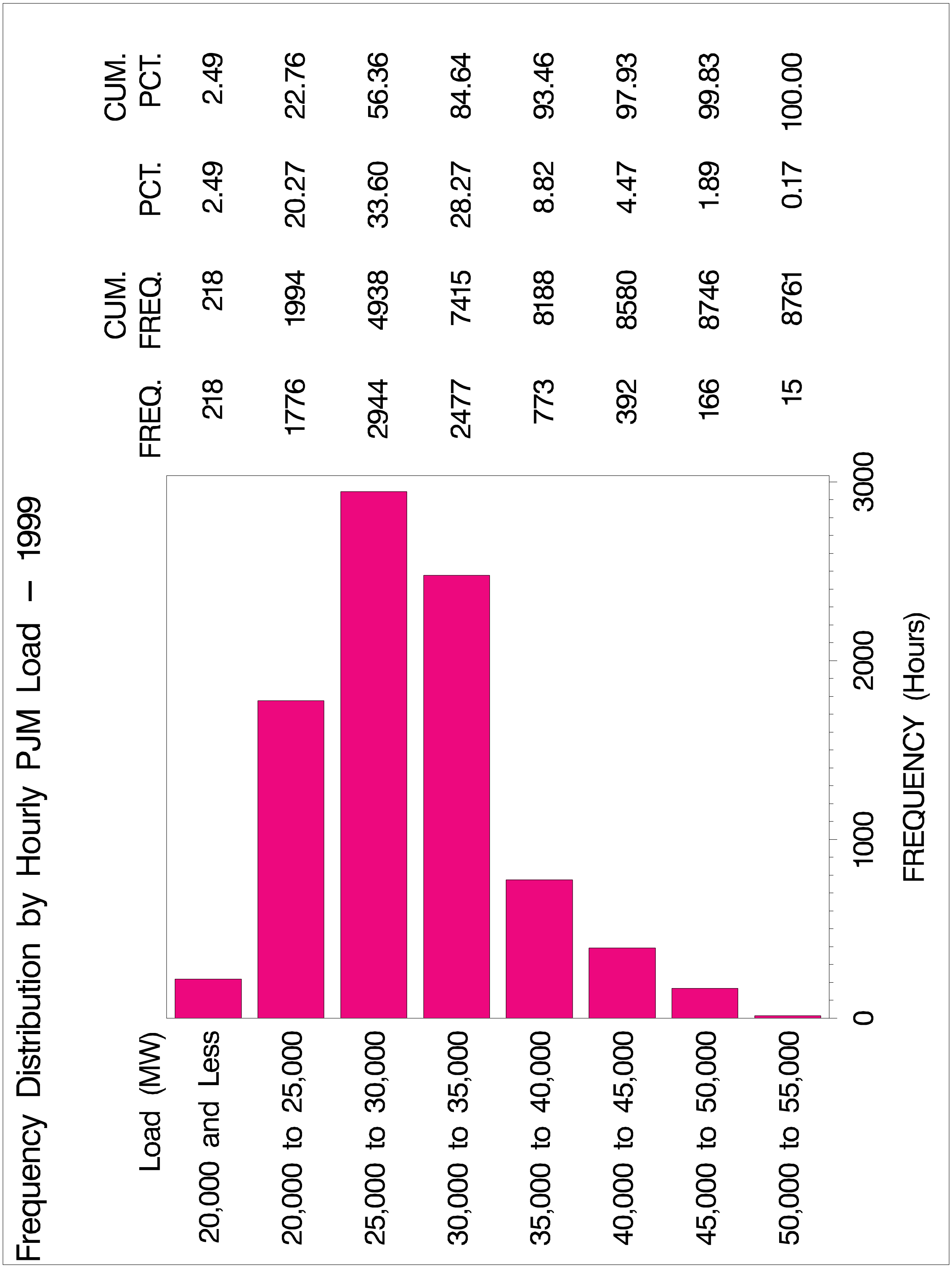


Figure C-9 Frequency Distribution of Hourly PJM Load: 2000

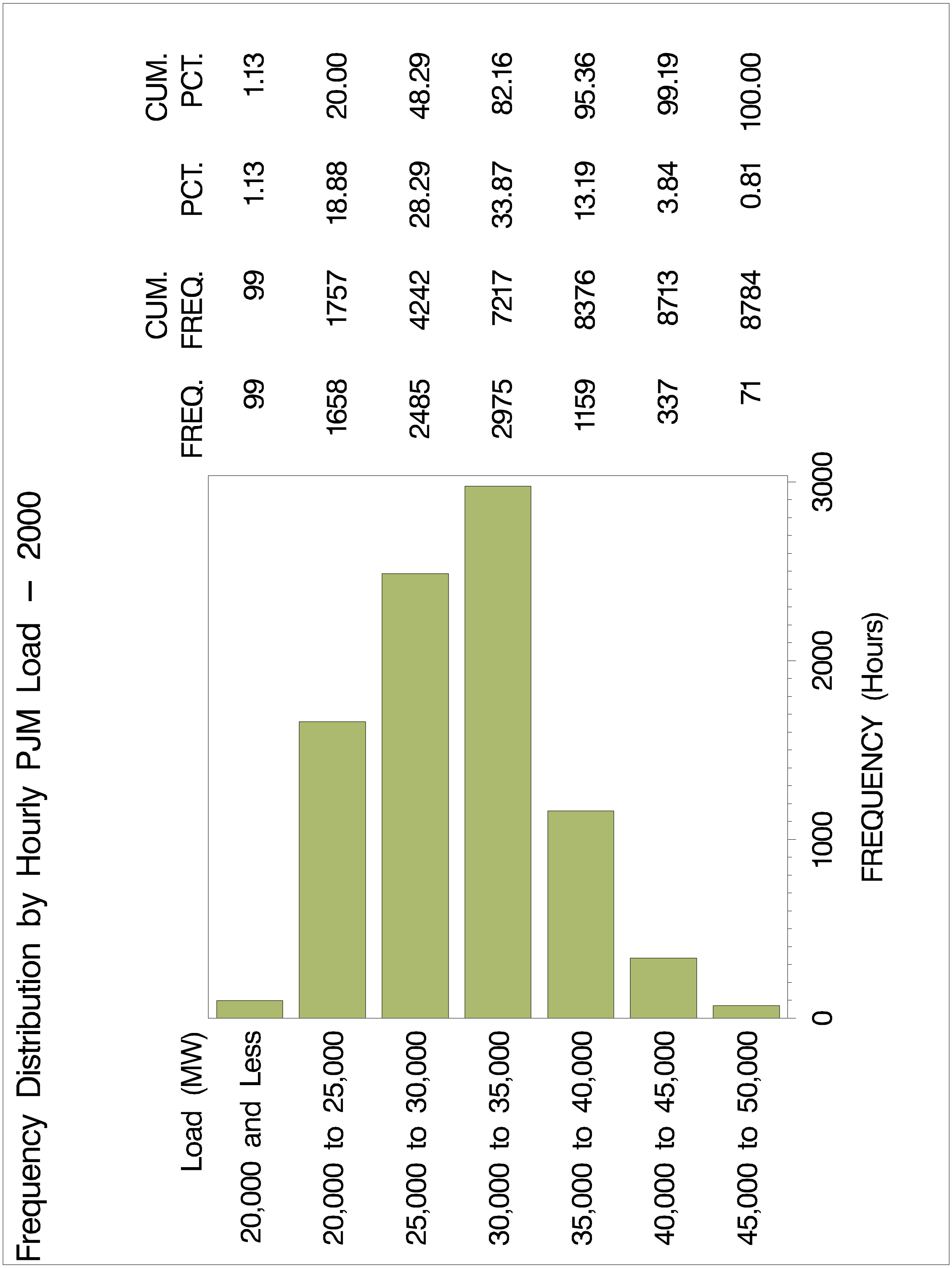


Figure C-10 Frequency Distribution of Hourly PJM Load: 2001

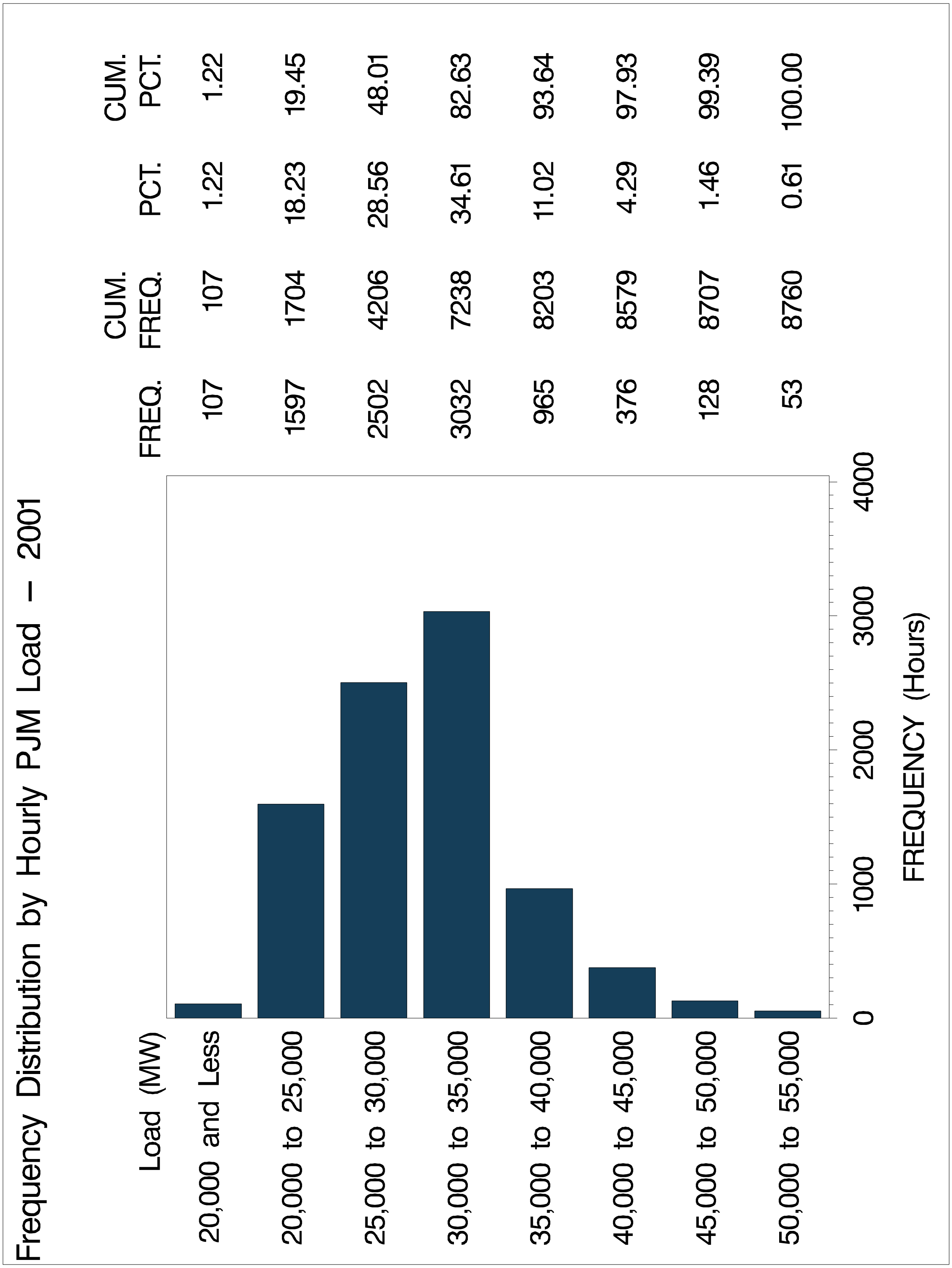
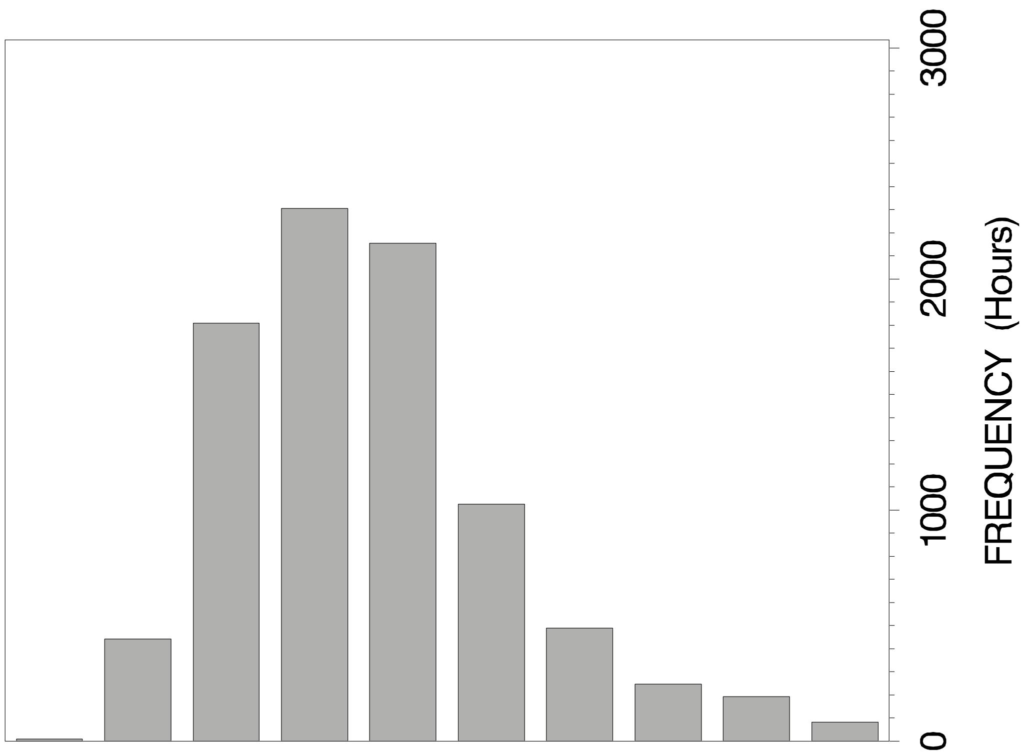


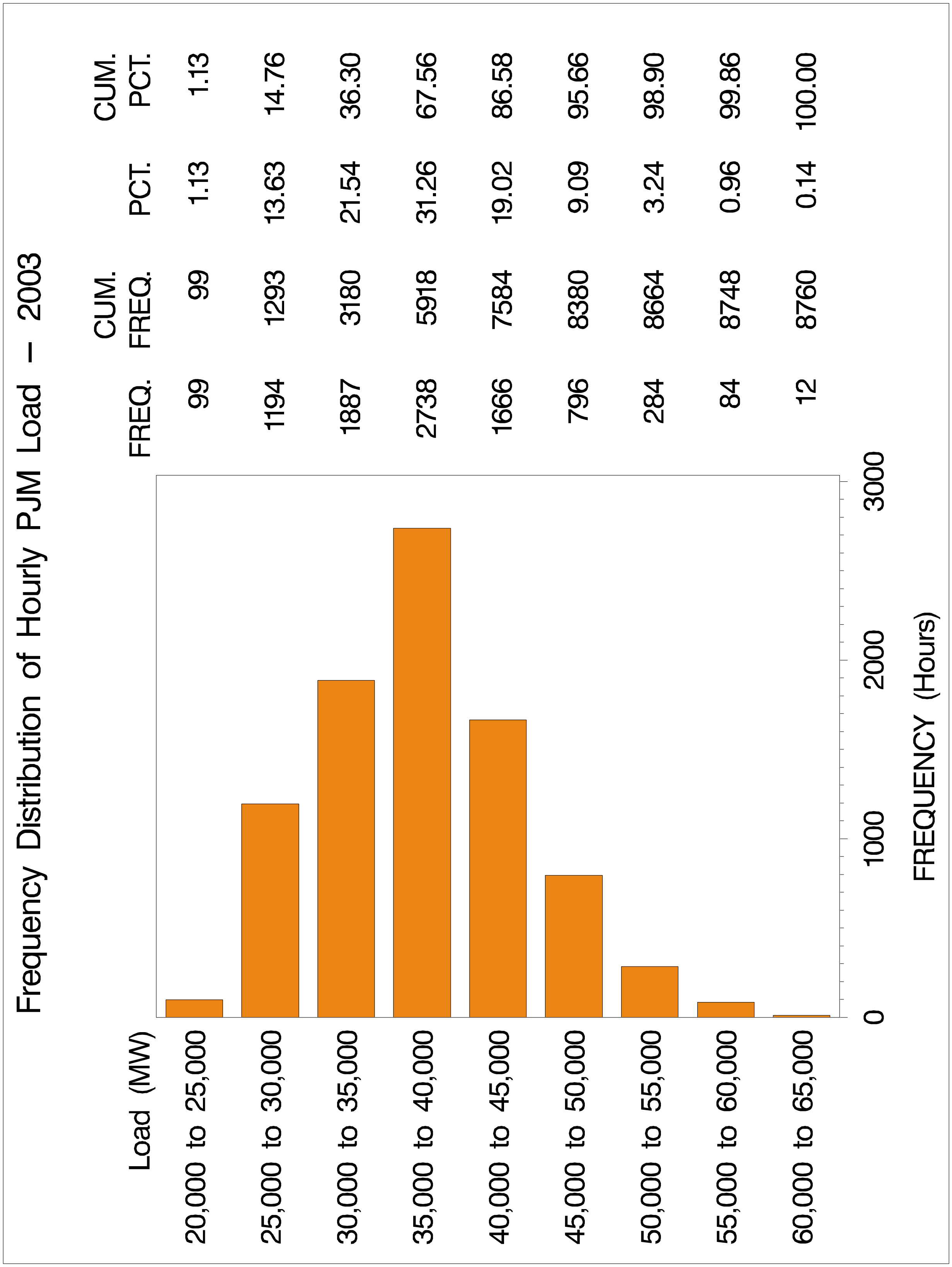
Figure C-11 Frequency Distribution of Hourly PJM Load: 2002

Frequency Distribution by Hourly PJM Load – 2002



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

Figure C-12 Frequency Distribution of Hourly PJM Load: 2003



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 to 25,000	99	99	1.13	1.13
25,000 to 30,000	1194	1293	13.63	14.76
30,000 to 35,000	1887	3180	21.54	36.30
35,000 to 40,000	2738	5918	31.26	67.56
40,000 to 45,000	1666	7584	19.02	86.58
45,000 to 50,000	796	8380	9.09	95.66
50,000 to 55,000	284	8664	3.24	98.90
55,000 to 60,000	84	8748	0.96	99.86
60,000 to 65,000	12	8760	0.14	100.00

In comparing the figures, one can see that, during each year, LMP was most frequently in the interval $10 per MWh to $20 per MWh. In 2003, however, LMP occurred in the interval from $20 per MWh to $30 per MWh nearly as frequently (24 percent in the $10 to $20 interval and 22 percent in the $20 to $30 interval). In 2003, LMP was less than $60 per MWh for 83 percent of the hours and less than $100 per MWh for 98 percent of the hours. LMP was $150 per MWh or greater for 11 hours (0.07 percent of the hours) in 2003.

Frequency Distribution of Load

Figure C-7, Figure C-8, Figure C-9, Figure C-10, Figure C-11 and Figure C-12 provide the frequency distribution of PJM load by number of hours, for 1998, 1999, 2000, 2001, 2002 and 2003. In 2003, the most frequently occurring load interval was 35,000 MW to 40,000 MW (31 percent of the hours). These figures show that, before the PJM Western Region was added in April 2002, the most frequently occurring load interval had been 30,000 MW to 35,000 MW. In 2003, load was less than 35,000 MW for 36 percent of the hours, less than 50,000 MW for 96 percent of the hours and less than 60,000 MW for all but 12 hours (0.14 percent of the hours). In 2002, load was less than 35,000 MW for 52 percent of the hours, less than 50,000 MW for 94 percent of the hours and less than 60,000 MW for 99 percent of the hours. The peak demand for the year occurred on August 22, 2003, with a peak demand of 61,500 MW.

Off-Peak and On-Peak Load

Table C-1 presents summary load statistics for 1998 to 2003 for the off-peak and on-peak hours, while Table C-2 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday through Friday) as the hour ending 0800 to the hour ending 2300, excluding NERC holidays. As one can see from the table, in 2003, on-peak load was about 20 percent higher than off-peak load. During the previous five years, on-peak load had been about 30 percent higher than off-peak load, while median peak load had ranged from 20 percent to 30 percent higher. With the addition of the PJM Western Region, average load during on-peak hours in 2003 was about 4 percent higher than in 2002. Off-peak load in 2003 was 6 percent higher than in 2002.

Table C-1 Off-Peak and On-Peak Load: 1998 to 2003 (in MW)

Year	Average Load			Median Load			Standard Deviation		
	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak	On-Peak/ Off-Peak
2003	33,595	41,755	1.2	32,971	40,802	1.2	5,546	5,424	1.0
2002	31,584	40,102	1.3	30,457	38,243	1.3	6,044	7,400	1.2
2001	26,804	34,303	1.3	26,433	33,076	1.3	4,225	4,851	1.1
2000	26,921	33,766	1.3	26,327	32,771	1.2	4,453	4,226	0.9
1999	26,409	33,291	1.3	25,795	31,987	1.2	4,862	4,870	1.0
1998	25,268	32,344	1.3	24,728	31,081	1.3	4,091	4,388	1.1

Table C-2 Year-Over-Year Percent Change in Load: 1998-1999 through 2002-2003

Year	Average Load		Median Load		Standard Deviation	
	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak
2003	6.4%	4.1%	8.3%	6.7%	-8.2%	-26.7%
2002	17.8%	16.9%	15.2%	15.6%	43.1%	52.5%
2001	-0.4%	1.6%	0.4%	0.9%	-5.1%	14.8%
2000	1.9%	1.4%	2.1%	2.5%	-8.4%	-13.2%
1999	4.5%	2.9%	4.3%	2.9%	18.8%	11.0%
1998	-	-	-	-	-	-

Off-Peak and On-Peak Load-Weighted LMP: 2002 and 2003

Table C-3 shows load-weighted average LMP for 2002 and 2003 during off-peak and on-peak periods. In 2002, the on-peak, load-weighted LMP was 80 percent greater than the off-peak LMP, while in 2003 it was 60 percent greater. On-peak, load-weighted, average LMP in 2003 was 25.6 percent higher than in 2002. Off-peak, load-weighted LMP in 2003 was 40.9 percent higher than in 2002. Similarly, both on-peak and off-peak median LMP were higher in 2003 than in 2002, by 42.5 percent and 26.6 percent, respectively. Dispersion in load-weighted LMP, as indicated by standard deviation, was 26.1 percent lower in 2003 than in 2002 during on-peak hours, while the standard deviation was 69.5 percent higher in 2003 than in 2002 during off-peak hours.

Table C-3 Off-Peak and On-Peak, Load-Weighted LMP for 2002 and 2003 (in Dollars per MWh)

	2003			2002			% Change 2002 to 2003	
	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak
Average LMP	$31.75	$49.97	1.6	$22.53	$39.79	1.8	40.9%	25.6%
Median LMP	$22.52	$46.08	2.0	$17.79	$32.34	1.8	26.6%	42.5%
Standard Deviation	$23.53	$23.88	1.0	$13.88	$32.33	2.3	69.5%	-26.1%

Fuel-Cost Adjustment

Fuel costs for 2002 and 2003 were taken from various published sources. Coal prices were obtained from The Energy Argus and adjusted for transportation costs. Both natural gas and petroleum prices were obtained from Platts and adjusted for transportation costs.

The price index for each fuel was calculated as a chain-weighted index, where the weights are the number of MW generated in each month of 2002 and 2003 for which the price was determined by the marginal generating unit firing the indicated fuel. First, an index was calculated using 2002 fuel-specific MW as the weights: (year 2003 fuel-specific prices times year 2002 fuel-specific MW) divided by (year 2002 fuel-specific prices times year 2002 fuel-specific MW). Second, an index was calculated using year 2003 fuel-specific MW as the weights: (year 2003 fuel-specific prices times year 2003 fuel-specific MW) divided by (year 2002 fuel-specific prices times year 2003 fuel-specific MW). The two indices were then chain-weighted by calculating their geometric mean. Each year 2003 hourly LMP for a month was then divided by the chain-weighted price index for that month to derive the fuel-cost-adjusted LMP. Fuel-cost-adjusted LMPs were then weighted by load to derive the load-weighted, fuel-cost-adjusted LMP.

LMP During Constrained Hours: 2002 and 2003

Figure C-13 shows the number of constrained hours during each month in 2002 and 2003 and the average number of constrained hours per month for each year.[3] There were 5,230 constrained hours in 2002 and 4,855 in 2003, a decrease of approximately 7 percent. Figure C-13 also shows that the average number of constrained hours per month was slightly less in 2003 than in 2002, with 405 per month in 2003 versus 436 per month in 2002.

Table C-4 presents summary statistics for load-weighted average LMP during constrained hours in 2002 and 2003. During constrained hours, the average, load-weighted LMP was 24 percent higher in 2003 than it was for constrained hours in 2002. During constrained hours, the median, load-weighted LMP was 43.1 percent higher in 2003 than in 2002, and the dispersion of LMP, as shown by the standard deviation, was 24.6 percent lower in 2003 than in 2002.

Table C-4 2002 and 2003 Load-Weighted Average LMP During Constrained Hours (in Dollars per MWh)

	2003	2002	Percent Change
Average LMP	$45.77	$36.90	24.0%
Median LMP	$41.77	$29.18	43.1%
Standard Deviation	$24.81	$30.93	-24.6%

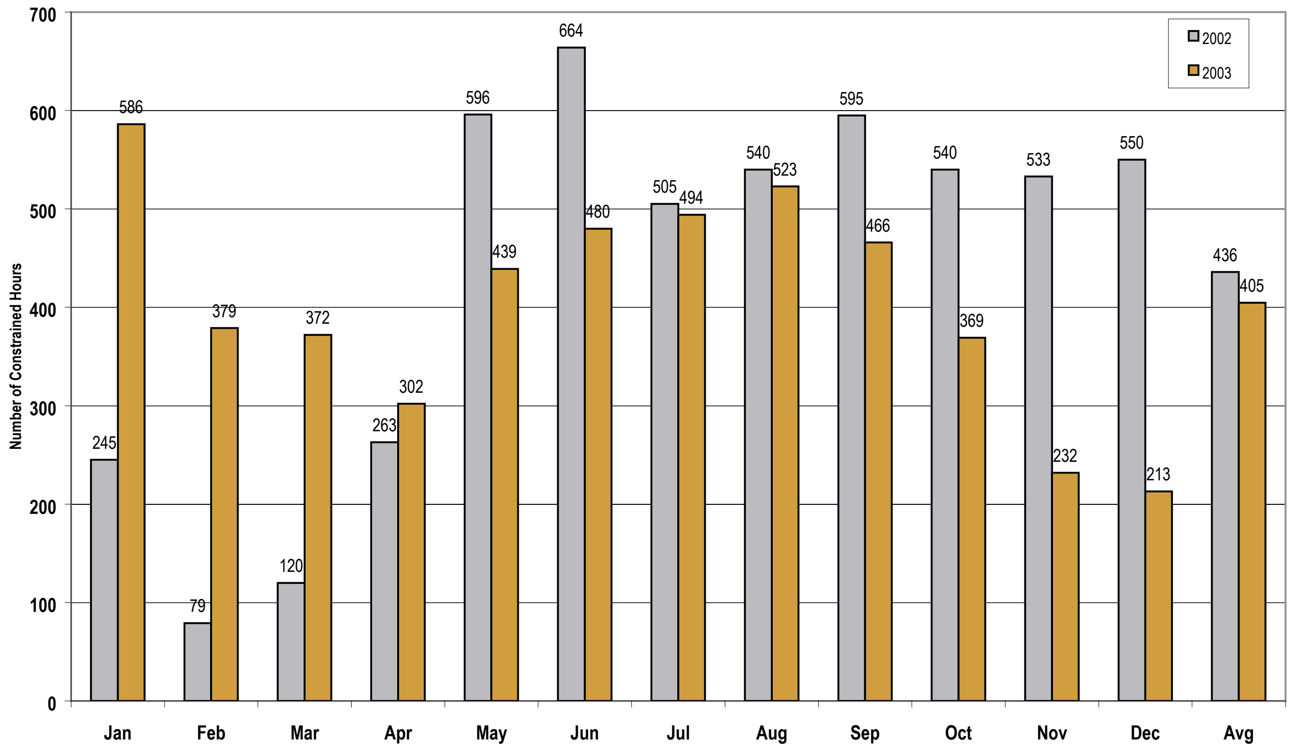
Table C-5 provides a comparison of load-weighted average LMP during constrained and unconstrained hours for the two years. In 2003, average load-weighted LMP during constrained hours was 31.2 percent higher than average load-weighted LMP during unconstrained hours. The comparable number for 2002 was 16.8 percent.

Table C-5 2002 and 2003 Load-Weighted Average LMP During Constrained and Unconstrained Hours (in Dollars per MWh)

	2003			2002		
	Unconstrained Hours	Constrained Hours	Percent Difference	Unconstrained Hours	Constrained Hours	Percent Difference
Average LMP	$34.87	$45.77	31.2%	$31.60	$36.90	16.8%
Median LMP	$25.24	$41.77	65.5%	$23.41	$29.18	24.6%
Standard Deviation	$24.84	$24.81	-0.1%	$26.74	$30.93	15.7%

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

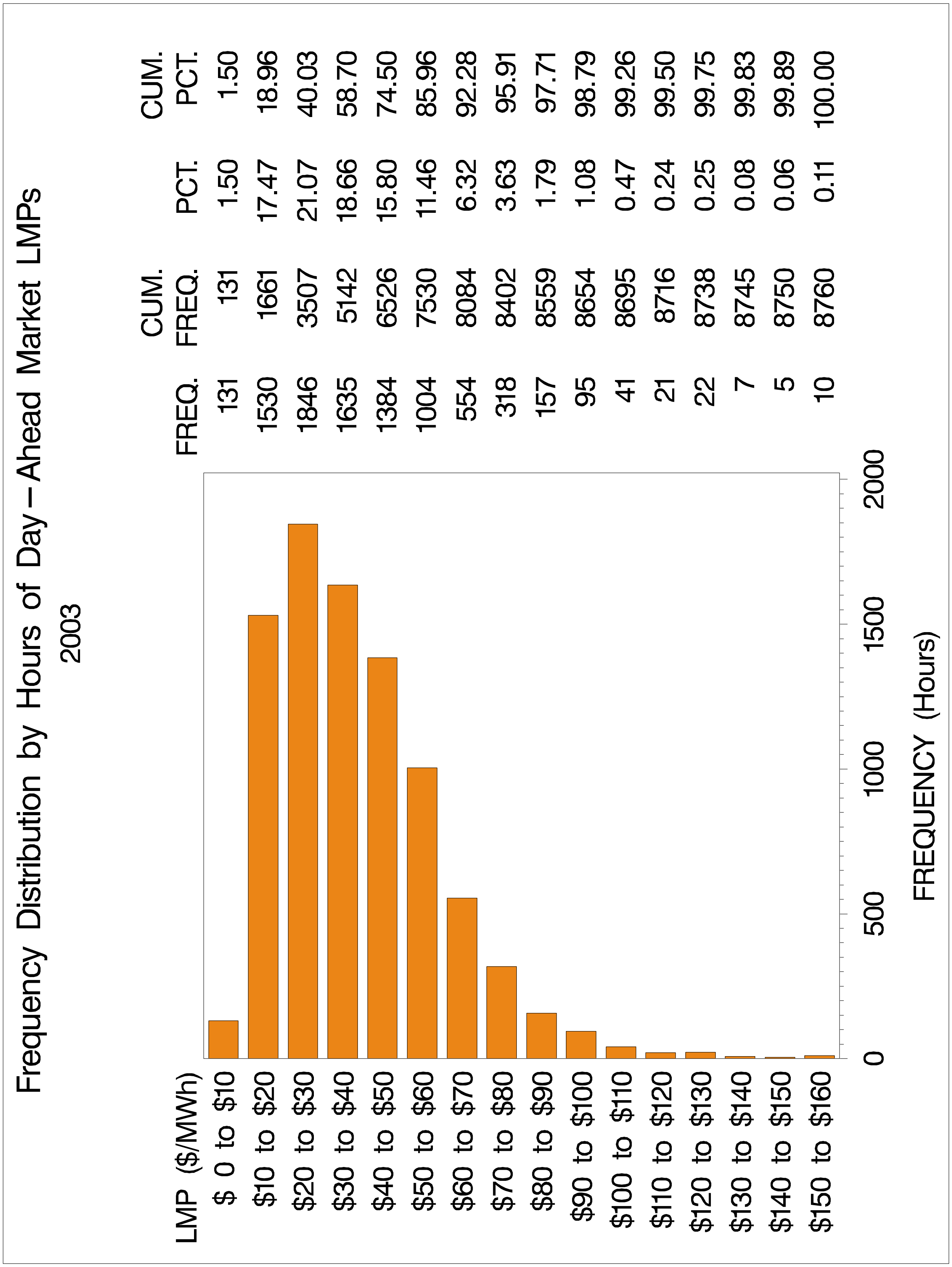
Figure C-13 PJM Constrained Hours: 2002 and 2003



Day-Ahead and Real-Time Prices

As noted earlier, real-time prices are only slightly lower than day-ahead prices on average, but real-time prices show greater dispersion. This pattern of average systemwide LMP price distribution for 2003 can be seen in Figure C-6 and Figure C-14. Together they show the frequency distribution by hours for the two markets. In PJM's Real-Time Market, both the $10-per-MWh to $20-per-MWh, and $20-per-MWh to $30-per-MWh intervals occurred with nearly equal frequency, 24 percent and 22 percent of the hours, respectively. The most frequently occurring price interval in the PJM Day-Ahead Energy Market was the $20-per-MWh to $30-per-MWh interval with 21 percent of the hours. The $30-per-MWh to $40-per-MWh interval was the next most frequent with 19 percent of the hours, only slightly above the $10-per-MWh to $20-per-MWh interval which occurred during 17 percent of the hours. In the Real-Time Market, prices were less than $30 per MWh for 49 percent of the hours, while prices were less than $30 per MWh in the Day-Ahead Market for 40 percent of the hours. Cumulatively, prices were less than $40 per MWh for 61 percent of the hours in the Real-Time Market and 59 percent of the hours in the Day-Ahead Market; less than $50 per MWh for 73 percent of the hours in the Real-Time Market and 75 percent of the hours in the Day-Ahead Market; less than $60 per MWh for 83 percent of the hours in the Real-Time Market and 86 percent of the hours in the Day-Ahead Market. In the Real-Time Market, prices were above $150 per MWh for 11 hours (0.07 percent of the hours), reaching a high for the year of $210.83 per MWh on February 16. In the Day-Ahead Market, prices were above $150 per MWh for 10 hours (0.11 percent of the hours), but reached a high for the year of $155.71 per MWh on March 11.

Figure C-14 Frequency Distribution by Hours of Day-Ahead Market LMP: 2003



Off-Peak and On-Peak LMP

Table C-6 shows average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Markets. Day-ahead and real-time on-peak average LMPs were about 70 percent higher than the corresponding off-peak average LMP. The real-time peak average LMP was 1.7 percent lower than the day-ahead peak average LMP. Median LMPs during on-peak hours were 94 percent and 111 percent higher in the Day-Ahead and Real-Time Markets, respectively, than median LMPs during off-peak hours. The day-ahead median on-peak LMP was also 2.9 percent higher than the real-time median on-peak LMP. Since the mean was above the median in these markets, both showed a positive skewness. The mean was, however, proportionately higher than the median in the Real-Time Market as compared to the Day-Ahead Market, during both on-peak and off-peak periods (9 percent and 39 percent compared to 8 percent and 25 percent, respectively). The difference reflects the larger positive skewness in the Real-Time Market. During on-peak hours, the standard deviation in the Real-Time Market was about 23 percent higher than in the Day-Ahead Market while it was 25 percent higher during off-peak hours.

Figure C-15 and Figure C-16 show the difference between real-time and day-ahead LMP in 2003 during the on-peak and off-peak hours, respectively. The average difference between real-time and day-ahead LMP during on-peak hours was only $0.81 per MWh (day-ahead LMP higher than real-time LMP). By contrast, during off-peak hours, the average difference between real-time and day-ahead LMP was $0.13 per MWh (day-ahead LMP higher than the real-time LMP). The figures also indicate that the largest price differences between the real-time and day-ahead LMPs, during both the off-peak and on-peak periods, occurred during the first quarter of 2003.

Table C-6 2003 Off-Peak and On-Peak LMP (in Dollars per MWh)

	Day-Ahead			Real-Time			% Change Day-Ahead to Real-Time	
	Off-Peak	On-Peak	On-Peak/ Off-Peak	On-Peak	On-Peak	On-Peak/ Off-Peak	On-Peak	On-Peak
Average LMP	$29.45	$49.35	1.68	$29.32	$48.54	1.66	-0.4%	-1.7%
Median LMP	$23.64	$45.76	1.94	$21.10	$44.45	2.11	-10.8%	-2.9%
Standard Deviation	$17.66	$19.05	1.08	$22.10	$23.52	1.06	25.1%	23.5%

LMP During Constrained Hours: Day-Ahead and Real-Time Markets

Figure C-17 shows the number of constrained hours in each month for the Day-Ahead and Real-Time Markets and the average number of constrained hours for 2003.[4] Overall, there were 4,855 constrained hours in the Real-Time Market and 7,874 constrained hours in the Day-Ahead Market, 62 percent more. Figure C-17 shows that in every month of 2003 the number of constrained hours in the Day-Ahead Market exceeded those in the Real-Time Market. On average for the year, the Day-Ahead Market had 62 percent more constrained hours than the Real-Time Market.

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

Figure C-15 Hourly Real-Time LMP minus Day-Ahead LMP: 2003 On-Peak Hours

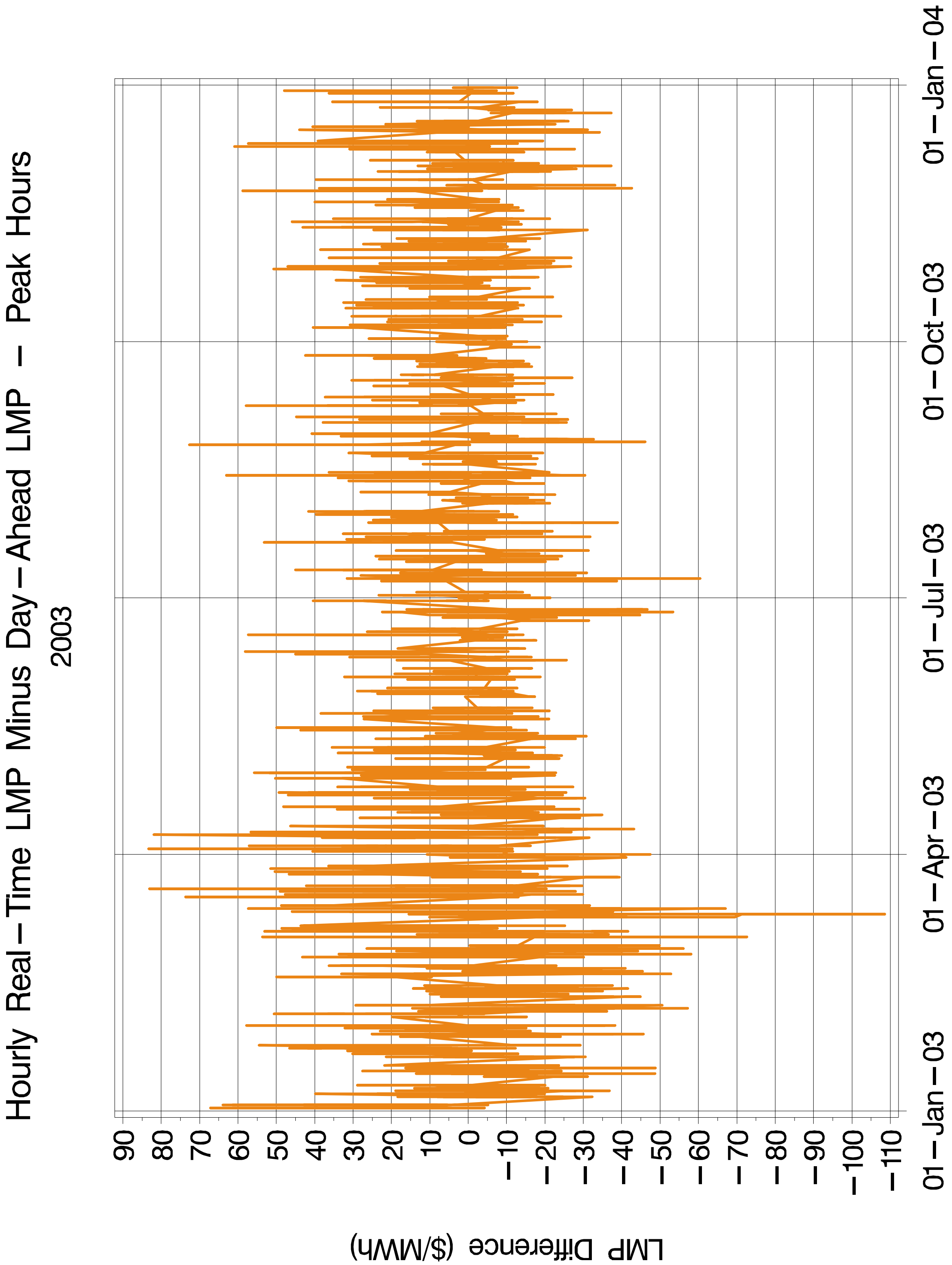


Figure C-16 Hourly Real-Time LMP minus Day-Ahead LMP: 2003 Off-Peak Hours

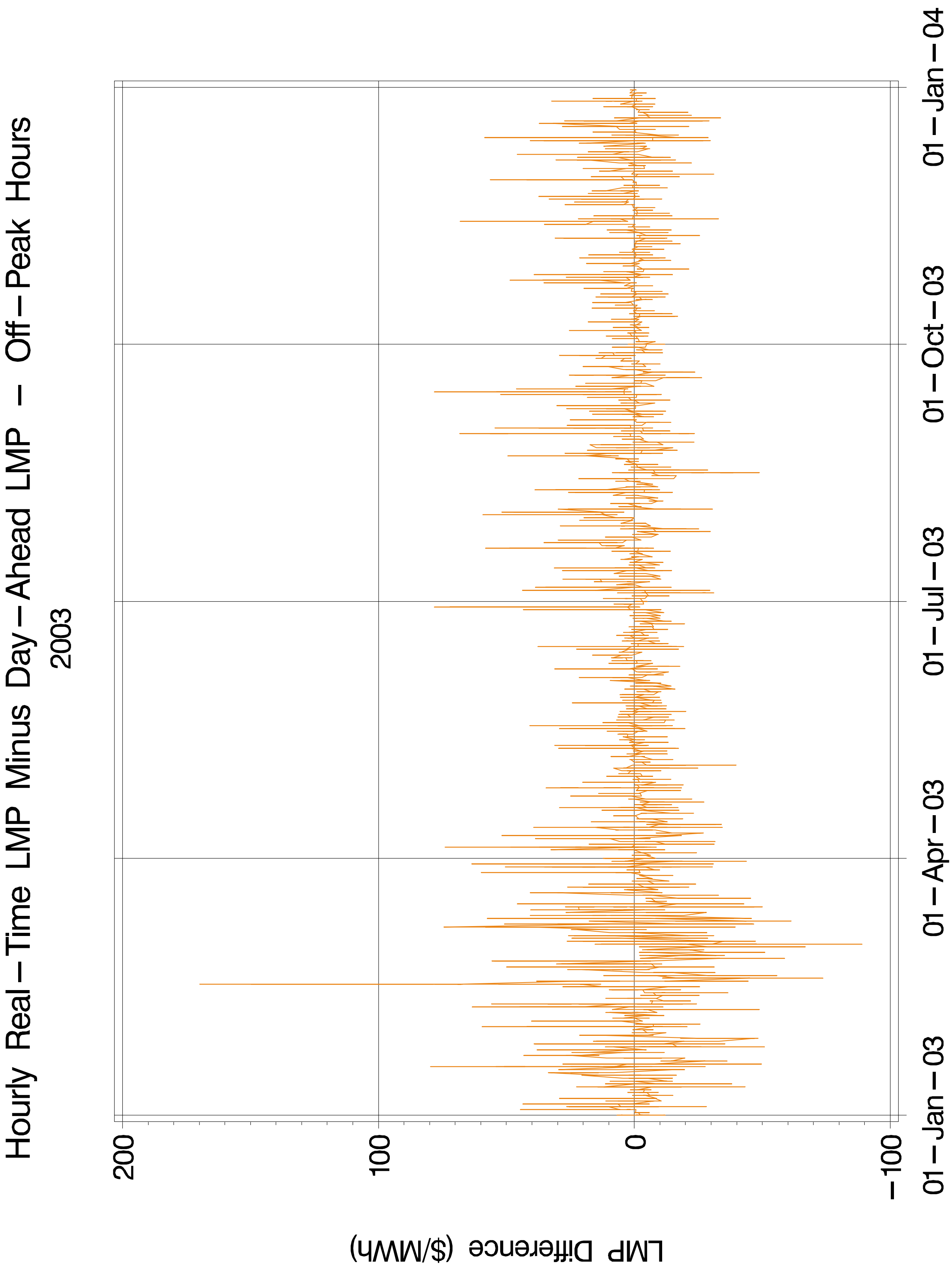


Figure C-17 Real-Time and Day-Ahead Market-Constrained Hours: 2003

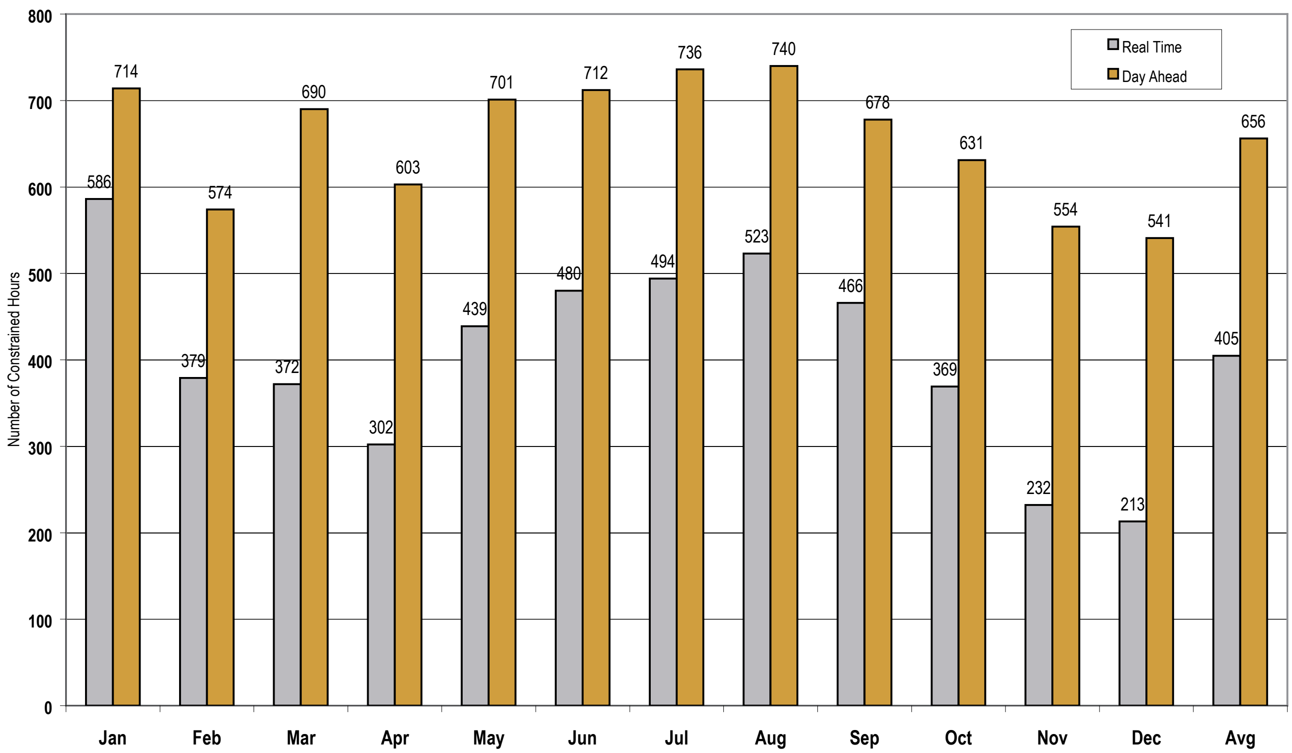


Table C-7 shows average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Markets. In the Day-Ahead Market, average LMP during constrained hours was 32.7 percent higher than average LMP during unconstrained hours. In the Real-Time Market, average LMP during constrained hours was 34.3 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 8.8 percent higher in the Real-Time Market than in the Day-Ahead Market. Both markets exhibited greater price dispersion during constrained hours than during unconstrained hours.

Table C-7 2003 LMP During Constrained and Unconstrained Hours (in Dollars per MWh)

	Day-Ahead			Real-Time		
	Unconstrained Hours	Constrained Hours	Percent Change	Unconstrained Hours	Constrained Hours	Percent Change
Average LMP	$29.93	$39.71	32.7%	$32.15	$43.19	34.3%
Median LMP	$20.19	$36.44	80.5%	$22.65	$38.26	68.9%
Standard Deviation	$21.97	$20.47	-6.8%	$23.80	$24.33	2.2%

Table C-7 shows that average LMP in the Day-Ahead Market during constrained hours was 2.6 percent higher than the overall average LMP for the Day-Ahead Market, while average LMP during unconstrained hours was 22.7 percent lower. In the Real-Time Market, average LMP during constrained hours was 12.9 percent higher than the overall average LMP for the Real-Time Market, while average LMP during unconstrained hours was 16 percent lower.

Appendix D – Capacity Markets

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Before retail restructuring, the original PJM members had determined their loads and related capacity obligations annually. Combined with state regulatory requirements to build and incentives to maintain adequate capacity, this system created a reliable pool, where capacity and energy were adequate to meet customer needs and where capacity costs were borne equitably by members and their loads.

Capacity obligations continue to be critical to maintaining reliability and to contribute to the effective, competitive operation of PJM Energy Markets. Adequate capacity resources, equal to expected load plus a reserve margin, help to ensure that energy is available on even the highest load days.

On January 1, 1999, in response to retail restructuring requirements, PJM introduced a transparent, PJM-run market in capacity credits.[1] New retail market entrants needed a way to acquire capacity credits to meet obligations associated with competitively gained load. Existing utilities needed a way to sell excess capacity credits when load was lost to new competitors. The PJM Capacity Credit Market provides a mechanism to balance supply and demand for capacity credits not met through the bilateral market or self-supply. The PJM Capacity Credit Market is designed to provide a transparent mechanism through which all competitors can buy and sell capacity based on need.

The "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Control Area" (RAA) states that as competitive markets evolve the purpose of capacity obligations is to "ensure that adequate Capacity Resources will be planned and made available to provide reliable service to loads within the PJM Control Area, to assist other Parties during Emergencies and to coordinate planning of Capacity Resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace."[2] When the PJM Western Region joined PJM, a new reliability assurance agreement was developed, the "PJM-West Reliability Assurance Agreement Among Load-Serving Entities in the PJM-West Region," that specified the Capacity Market rules initially implemented in the PJM Western Region.

Under the RAA for both the PJM Mid-Atlantic and Western Regions, each load-serving entity (LSE) must own or purchase capacity resources greater than or equal to its capacity obligation. To cover this responsibility, LSEs may own or purchase capacity credits, unit-specific installed capacity or capacity imports.

On April 1, 2002, the PJM Western Region joined PJM. On June 1, 2003, the PJM Western Region Capacity Market and the PJM Mid-Atlantic Region Capacity Market were combined into a single market, referred to as the PJM Capacity Market. The PJM Capacity Market currently operates under the same common set of rules previously associated with the PJM Mid-Atlantic Region alone.

1 The first Capacity Credit Markets (CCMs) were run in late 1998, with an effective date of January 1, 1999.
2 "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Control Area," revised March 21, 2000 (RAA), Article 2 – "Purpose," page 8.

Capacity Obligations

For the PJM Mid-Atlantic and Western Regions, an annual load forecast is used to determine the forecast peak load for each region. These forecast peak load values are further adjusted to determine capacity obligations.

- **PJM Mid-Atlantic Region.** In the PJM Mid-Atlantic Region, the adjusted forecast peak load value[3] is multiplied by the forecast pool requirement (FPR) to determine the unforced capacity obligation. The FPR is equal to one plus a reserve margin, multiplied by the PJM Mid-Atlantic Region unforced outage factor. An LSE's unforced capacity obligation is its forecast peak load multiplied by the FPR. The FPR is set for each planning period which commences every June 1.

- **PJM Western Region.** Prior to June 1, 2003, in the PJM Western Region, the forecast peak load was multiplied by 6 percent to determine, for each entity, its maximum daily available capacity obligation (DACO). Unlike the PJM Mid-Atlantic Region in which the unforced capacity obligation is set annually and must be met on a daily basis, the DACO of the PJM Western Region was set daily, based on the daily load forecast, and had to be met on a daily basis. The DACO could not exceed 106 percent of the forecast period peak load (FPPL).

Beginning June 1, 2003, the PJM Mid-Atlantic and Western Regions' Capacity Markets were combined into a single, systemwide PJM Capacity Market with rules identical to those for the PJM Mid-Atlantic Region's market alone. Those rules now provide the framework within which LSEs throughout the PJM service area meet their capacity obligations.

Meeting Capacity Obligations

Two Capacity Markets before June 1, 2003

- **PJM Mid-Atlantic Region.** In the PJM Mid-Atlantic Region (then known as PJM-Eastern Region), an LSE's load could change on a daily basis as customers switched suppliers. The unforced capacity position of every such LSE was calculated daily when its capacity resources were compared to its capacity obligation to determine whether any LSE was short of capacity resources. Deficient entities had to contract for capacity resources to satisfy their deficiency. Any LSE that remained deficient had to pay an interval penalty equal to the capacity deficiency rate (CDR) times the number of days in an interval.[4] If an LSE was short because of a short-term load increase, it paid only the daily penalty until the end of the month. In no case was a deficient LSE charged more than the CDR multiplied by the number of days in the interval multiplied by each MW of deficiency.

- **PJM Western Region.** In the PJM Western Region (then known as PJM-West), an LSE's load changed daily, both because of customers switching suppliers and because of changing daily load forecasts. In the PJM Western Region only currently available units could be used to meet the DACO. If an LSE remained deficient, it was charged the PJM Western Region CDR (then set at $12,755.29 per MW-day), for each deficiency day. In no circumstance was an LSE required to pay more than $63,776.45 for each deficient MW during the period beginning June 1, 2002, and ending May 31, 2003. LSEs were permitted to pay only a daily CDR, then set at $174.73 per MW-day, for their deficiency if they chose to carry a portfolio of installed capacity valued at 118 percent of their respective forecast peak period load.

One Capacity Market after June 1, 2003

On June 1, 2003, the PJM Mid-Atlantic Capacity Market and the PJM Western Region Capacity Market became one market, the PJM Capacity Market, whose rules are the same as those that had governed the PJM Mid-Atlantic Region Capacity Market prior to June 1, 2003. Beginning June 1, 2003, any PJM LSE's load may change on a daily basis as customers switch suppliers. The unforced capacity position of every such LSE is calculated daily when

3 Adjusted for active load-management (ALM) and local diversity.

4 The CDR is a function both of the annual carrying costs of a combustion turbine (CT) and the forced outage rate and thus may change annually. The CDR was changed to $174.73 per MW-day, effective June 1, 2002, and to $170.96 per MW-day, effective June 1, 2003.

its capacity resources are compared to its capacity obligation to determine whether any LSE is short of capacity resources. Deficient entities must contract for capacity resources to satisfy their deficiency. Any LSE that remains deficient must pay an interval penalty equal to the CDR (currently $170.96 per MW-day), times the number of days in an interval. If an LSE is short because of a short-term load increase, it pays only the daily penalty until the end of the month. In no case is a deficient LSE charged more than the CDR multiplied by the number of days in the interval times each MW of deficiency.

Capacity Resources

Capacity resources are defined as MW of net generating capacity meeting specified PJM criteria. They may be located within or outside of the service area, but they must be committed to serving specific PJM loads. All capacity resources must pass tests regarding the capability of generation to serve load and to deliver energy. This latter criterion requires adequate transmission service.[5]

Capacity resources may be bought in three different ways:

- **Bilateral, from an internal PJM source.** Internal, bilateral purchases may be in the form of a sale of all or part of a specific generating unit, or in the form of a capacity credit, defined in terms of unforced capacity and measured in MW.

- **Bilateral, from a generating unit external to PJM.** External, bilateral purchases (capacity imports) must meet PJM criteria, including that imports are from specific generating units and that sellers have firm transmission from the identified units to the metered boundaries of the PJM service area.

- **Capacity Credit Markets.** Market purchases may be made from PJM Daily, Monthly, Multimonthly or Interval Capacity Credit Markets.

The sale of a generating unit as a capacity resource within PJM entails obligations for the generation owner:

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity resources from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit and sold outside PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures.[6] The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load within the service area. When PJM invokes the recall right, the energy supplier is paid the PJM real-time, spot market energy price.

- **Day-Ahead Energy Market Offer Requirement.** Owners of capacity resources are required to offer their output into PJM's Day-Ahead Energy Market. When LSEs purchase capacity, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, resource owners must provide the offered energy at the offered price. This energy can be provided either from the specific unit offered or by purchasing the energy bilaterally, or at the spot market price, and reselling the energy at the offer price.

- **Deliverability.** In order to qualify as a capacity resource, energy from the generating unit must be deliverable to load on the PJM system. Capacity resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system that may have a capacity deficiency. In addition, for capacity resources located outside the metered boundaries of the PJM region and used to meet an accounted-for obligation, capacity and energy must be delivered to the metered boundaries of the PJM region through firm transmission service.

5 See RAA, "Capacity Resources," page 2.
6 PJM emergency procedures are defined in the "PJM Manual for Emergency Operations."

- **Generator Outage Reporting Requirement.** Owners of capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.

- **Financial Transmission Right.** A Financial Transmission Right (FTR) was, prior to implementation of the ARR allocation rules on June 1, 2003, available to load only if a specific capacity resource was identified as the source of the delivered energy.[7] Since a capacity credit is not unit-specific, it could not be the basis for an FTR. Under the current ARR allocation rules, an ARR is available to load only if a specific capacity resource is identified as the source of the delivered energy. The next modification of the ARR allocation rules, which will be effective June 1, 2004, breaks the link between capacity resources and ARRs. After June 1, 2004, customers may request ARRs from the resources that were historically designated to serve load in a transmission zone or a load aggregate.

The first three obligations associated with sale of capacity resources are clearly essential to the definition of a capacity resource and contribute directly to system reliability.

Market Dynamics

RAA procedures determine PJM's total capacity obligation and thus the total demand for capacity credits. The RAA includes rules for allocating total capacity obligation to individual LSEs. This obligation is equivalent to a fixed total demand, net of active load-management (ALM), bilateral contracts and self-supply, that must be bid into PJM's Interval, Multimonthly, Monthly or Daily Capacity Credit Markets. Demand for capacity credits in daily markets is the residual demand after capacity credits are purchased in PJM's longer term Capacity Credit Markets or through bilateral transactions.

The supply of capacity credits in all PJM Capacity Credit Markets is a function of:

- Physical capacity in the PJM service area;
- Prices in external energy and capacity markets;
- Prices in the PJM Energy and Capacity Markets;
- Capacity resource imports; and
- Transmission service availability and price.

While physical generating units in PJM are the primary source of capacity resources, capacity resources can be delisted, i.e., exported, from PJM and imported from regions external to PJM, subject to transmission limitations. It is the ability to export and to import capacity resources that makes capacity supply in PJM a function of price in both internal and external capacity and energy markets.

In capacity markets, as in other markets, market power is the ability of a market participant to increase market price above the competitive level. The competitive market price is the marginal cost of producing the last unit of output, assuming no scarcity and including opportunity costs. For capacity, the opportunity cost of selling into the PJM Capacity Market is the additional revenue foregone from not selling into an external energy and/or capacity market.

Generation owners can be expected to sell capacity into the most profitable market. The competitive price in the capacity markets is a function of the marginal cost of capacity. The marginal cost of capacity is, in turn, determined by the time period over which a choice is made as well as the alternative opportunities available to the generation owner. If an owner is considering whether to sell a capacity resource for a year, marginal costs would include the incremental costs of maintaining the unit so that it can qualify as a capacity resource and any relevant

7 An ARR is an Auction Revenue Right.

opportunity costs. If an owner is considering whether to sell a capacity resource for a day, the only relevant costs are the opportunity costs. The opportunity cost associated with the sale of a capacity resource is a function of the expected probability that the energy will be recalled and the expected distribution of the difference between external and internal energy prices.

Generators can be expected to evaluate the opportunities to sell capacity on a continuing basis, over a variety of time frames, depending on the rules of the capacity markets. The existence of interval markets makes the generators' decisions more dependent on assessments of seasonal energy market price differentials and recall probabilities. With longer capacity obligations, the likelihood of the net external price differential exceeding the capacity penalty for the period is lower and, therefore, the incentives to sell the system short are lower.

Appendix E — Glossary

Active load management (ALM)	ALM is end-use customer load which can be interrupted at the request of PJM. Such PJM request is considered an emergency action and is implemented prior to a voltage reduction. ALM derives an ALM credit in the accounted-for-obligation.
Aggregate	Combination of buses or bus prices.
Ancillary service	Those services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission provider's transmission system in accordance with good utility practice.
Area control error (ACE)	The ACE of the PJM control area is the actual net interchange minus the biased scheduled net interchange and a frequency deviation component.
Auction Revenue Right (ARR)	Financial instrument entitling its holder to FTR auction revenue based on LMP differences across a specific path in the annual FTR auction.
Average hourly unweighted LMP	Average hourly LMP is calculated by averaging hourly LMP without any weighting.
Balancing market evaluation (BME)	The NYISO defines BME as, "An evaluation performed by the NYISO for the hour in which the dispatch occurs. The BME begins seventy-five (75) minutes before the beginning of the hour in which dispatch occurs. Based upon the Day-Ahead commitment and updated Load forecasts and Generator schedules, BME will assess new Bids for the Locational Based Marginal Pricing ("LBMP") Markets and requests for new Bilateral Transaction schedules for the Dispatch Hour to which the Security Constrained Unit Commitment (SCUC) applies. BME will redispatch Internal Generators, schedule External Generators, schedule new Bilateral Transactions if feasible, update Desired Net Interchanges if needed, and Reduce or Curtail Bilateral Transactions with non-Firm and Firm Transmission Service as needed for the dispatch Hour for which the SCUC applies."[1]
Basic generation service (BGS)	The default electric generation service provided by the electric public utility to consumers who do not elect to buy electricity from a third-party supplier.
Bilateral agreement	Agreement between two parties for the sale and delivery of a service.

1 New York Independent System Operator, "Definitions/Glossary" http://www.nyiso.com/services/training/glossary/index.html (23 February 2004).

Black start unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the transmission system.
Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generation site equalling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity credit	An entitlement to a specified number of MW of unforced capacity from a capacity resource for the purpose of satisfying capacity obligations imposed under the RAA.
Capacity deficiency rate (CDR)	The capacity deficiency rate is based on the annual carrying charges for a new combustion turbine, installed and connected to the transmission system. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Markets	All markets where PJM members can trade capacity.
Capacity queue	A collection of RTEPP capacity resource project requests that are received during a particular timeframe. There are typically two queues per year and they are referred to alphabetically.
Combined-cycle (CC)	A generating unit generally consisting of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover.
Decrement bids	Financial offers to purchase specified amounts of MW in the Day-Ahead Market at or above a given price.
Dispatch rate	Control signal, expressed in dollars per MWh, calculated by PJM and transmitted continuously and dynamically to generating units to direct the output level of all generation resources dispatched by the PJM OI.
End-use customer	Any customer purchasing electricity at retail.
External resource	A resource located outside metered PJM boundaries.

Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Market across a specific path.
Firm point-to-point transmission	Firm transmission service that is reserved and/or scheduled between specified points of receipt and delivery.
Firm transmission	Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is, however, subject to an emergency, an unanticipated failure of a facility or other event.
Fixed-demand bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Generation offers	Schedules of MW offered and the corresponding offer price.
Generator owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.
Gross deficiency	The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as accounted-for deficiency.
Gross excess	The sum of all LSE's individual excess capacity, or the excess of unforced capacity above unforced capacity obligation. The term is referred to as "Accounted-for Excess" in the "PJM Accounted-For Obligation Manual" (Manual 17).
Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz (hz)	Electricity system frequency is measured in hertz.
Increment offers	Financial offers in the Day-Ahead market to supply specified amounts of MW at or above a given price.
Installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
Interval Market	The Capacity Market rules provide for three Interval Markets, covering the months from January through May, June through September and October through December.

Load	Demand for electricity at a given time.
Load aggregator	An entity licensed to sell energy to retail customers located within the service territory of a local distribution company.
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power markets.
Marginal unit	The last generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be either a market supplier, a market buyer or both. Market buyers and market sellers are members that have met reasonable creditworthiness standards established by the OI. Market buyers are otherwise able to make purchases and market sellers are otherwise able to make sales in the PJM Energy or Capacity Credit Markets.
Mean	The arithmetic average.
Median	The midpoint of data values. Half the values are above and half below the median.
Megawatt (MW)	A unit of power equal to 1,000 kilowatts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt hour (MWh)	One MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Monthly CCMs	The capacity credits cleared each month through the PJM Monthly Capacity Credit Markets (CCMs).
Multimonthly CCMs	The capacity credits cleared through PJM Multimonthly Capacity Credit Markets (CCMs).
Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of LSE obligations.
Net exports (capacity)	Capacity exports (or delists) less capacity imports.

North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.
Obligation	The sum of all load-serving entities' unforced capacity obligations is determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holiday (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 7:00 a.m.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 8:00 a.m. until the hour ending at 11:00 p.m.
PJM member	Any entity that has completed an application and satisfies the requirements of PJM to conduct business with the PJM OI including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Price duration curve	Represents the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Regional Transmission Expansion Planning Protocol	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.
Residual capacity	Capacity that is unsold after markets clear.
Residual supply index (RSI)	RSI measures the percent of supply remaining in the market net of each generation owner's supply. RSI for generator "i" is: $[(Supply_m - Supply_i) / (Demand_m)]$ Where $Supply_m$ is total supply in an energy market plus net imports. $Supply_i$ is the supply owned by the generation owner "i" and $Demand_m$ is total market demand.

Self-scheduled generation	Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
Sources and sinks	Sources are the injection end of a transmission transaction. Sinks are the withdrawal end of a transaction.
Spinning reserve	Reserve capability which is required in order to enable an area to restore its tie-lines to the precontingency state within 10 minutes of a contingency which causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. During system restoration customer load may be classified as spinning reserve.
Standard deviation	A measure of data variability around the mean.
System lambda	The cost to the PJM system of generating the next unit of output.
Unforced capacity	Installed capacity adjusted by forced outage rates.

Appendix F — List of Acronyms

ACE	Area control error
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEP	American Electric Power Company, Inc.
ALM	Active Load Management
APS	Allegheny Power
ARR	Auction Revenue Rights
BGE	Baltimore Gas and Electric Company
BGS	Basic Generation Service
BME	Balancing Market Evaluation
CCM	Capacity Credit Market
CC	Combined cycle
CDR	Capacity Deficiency Rate
CDTF	Cost Development Task Force
CPS	Control Performance Standard
CT	Combustion turbine
CUM FREQ	Cumulative frequency
CUM PCT	Cumulative percent
DA	Day ahead
DCS	Disturbance control standard

DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva North
DPLS	Delmarva South
DSR	Demand Side Response
ECAR	East Central Area Reliability Council
EFORd	Equivalent demand forced outage rate
EHV	Extra high voltage
FE	FirstEnergy Corp.
FERC	United States Federal Energy Regulatory Commission
FPPL	Forecast period peak load
FPR	Forecast pool requirement
FREQ	Frequency
FTR	Financial Transmission Rights
HHI	Herfindahl-Hirschman Index
ICAP	Installed capacity
IMO	Independent Electricity Market Operator for Ontario
IPP	Independent Power Producer
ISO	Independent System Operator
JCPL	Jersey Central Power & Light Company
LMP	Locational marginal price

LSE	Load-serving entity
LTE	Long-term emergency
MAIN	Mid-America Interconnected Network, Inc.
MAAC	Mid-Atlantic Area Council
MAPP	Mid-Continent Area Power Pool
MCP	Market-clearing price
Met-Ed	Metropolitan Edison Company
MEW	Western subarea of Metropolitan Edison Company
MP	Market participant
MMU	PJM Market Monitoring Unit
NERC	North American Electric Reliability Council
NYISO	New York Independent System Operator
OA	PJM Operating Agreement
OASIS	Open Access Same-Time Information System
ODEC	Old Dominion Electric Cooperative
OI	PJM Office of the Interconnection
PCT	Percent
PE	PECO zone
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
PEPCO	Pepco (formerly Potomac Electric Power Company)

PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/IMO	PJM/IMO interface pricing point
PJM/NYIS	PJM/NYISO interface pricing point
PPL	PPL Electric Utilities Corporation
PSEG	Public Service Electric and Gas Company
PSN	PSEG north
PSNC	PSEG northcentral
QIL	Qualified Interruptible Load
RAA	Reliability Assurance Agreement
RECO	Rockland Electric Company zone
RMCP	Regulation Market clearing price
RSI	Residual supply index
RT	Real time
RTEPP	Regional Transmission Expansion Planning Protocol
SCPA	Southcentral Pennsylvania subarea
SEPJM	Southeastern PJM subarea
SFT	Simultaneous feasibility test

SMECO	Southern Maryland Electric Cooperative
SNJ	Southern New Jersey
SPP	Southwest Power Pool, Inc.
SRMCP	Spinning Reserve Market clearing price
STE	Short-term emergency
TLR	Transmission loading relief
UGI	UGI Utilities, Inc.
VAP	Virginia Electric and Power Company