SECTION 5 – CAPACITY MARKETS

Each organization serving PJM load must own or acquire capacity resources to meet its capacity obligations. Load-serving entities (LSEs) can acquire capacity resources by entering into bilateral agreements, by participating in the PJM-operated Capacity Credit Market or by constructing generation. LSEs can reduce their capacity obligations by participating in relevant demand-side response programs. Collectively, all arrangements by which LSEs acquire capacity are known as the Capacity Market.[1]

The PJM Capacity Credit Market[2] provides mechanisms to balance supply of and demand for capacity unmet by the bilateral market or self-supply. The PJM Capacity Credit Market consists of the Daily, Interval,[3] Monthly and Multimonthly Capacity Credit Markets. The PJM Capacity Credit Market is intended to provide a transparent, market-based mechanism for competitive retail LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. The PJM Daily Capacity Credit Market permits LSEs to match capacity resources with short-term shifts in retail load while Interval, Monthly and Multimonthly Capacity Credit Markets provide mechanisms to match longer term obligations with capacity resources.

From June 2004 through May 2005 a separate ComEd Capacity Credit Market operated, under the terms of PJM rules, to balance supply of and demand for capacity unmet by the bilateral market or self-supply in the ComEd Control Area.[4] The ComEd Capacity Credit Market consisted of Interval, Monthly and Multimonthly Capacity Credit Markets.

During the last two calendar years, PJM has integrated five control zones. In the *2004 State of the Market Report* the calendar year was divided into three phases, corresponding to market integration dates. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[5]

- **Phase 1 (2004).** The four-month period from January 1 through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[6] and the Allegheny Power Company (AP) Control Zone.[7]

- **Phase 2 (2004).** The five-month period from May 1 through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the Commonwealth Edison Company Control Area (ComEd).[8]

1 See Appendix H, "Glossary," for definitions of PJM Capacity Credit Market terms.

2 All PJM Capacity Market values (capacities) are in terms of unforced MW.

3 PJM defines three intervals for its Capacity Markets. The first interval extends for five months and runs from January through May. The second interval extends for four months and runs from June through September. The third interval extends for three months and runs from October through December.

4 All ComEd Capacity Market values (capacities) are in terms of installed MW.

5 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

6 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

7 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

8 During the five-month period May 1, 2004, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

- **Phase 3 (2004).** The three-month period from October 1 through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- **Phase 4 (2005).** The four-month period from January 1 through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1 through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone.

Overview

When the 2004 calendar year ended, PJM was operating two Capacity Markets, the PJM Capacity Market and the ComEd Capacity Market. The PJM Capacity Market (or simply PJM) was comprised of the 11 control zones of the Mid-Atlantic Region and the AP, AEP and DAY Control Zones. DLCO, which joined PJM on January 1, 2005, and Dominion, which joined PJM on May 1, 2005, were added to the PJM Capacity Market on the dates they joined. The ComEd Capacity Market was comprised solely of the ComEd Control Zone.

The ComEd Capacity Credit Market was added to the PJM Capacity Credit Market on June 1, 2005, to create a single PJM Capacity Market.[9]

PJM Capacity Market

Market Structure for the PJM Capacity Market

Ownership Concentration

- **Phase 4.** Structural analysis of the PJM Capacity Credit Market found that, on average, its daily markets exhibited low concentration levels while its monthly and multimonthly markets exhibited moderate concentration levels during the period January through April 2005.

- **Phase 5.** Structural analysis of the PJM Capacity Credit Market found that, on average, its daily markets exhibited moderate concentration levels while its monthly and multimonthly markets exhibited high concentration levels during the period May through December 2005.

- **Total Capacity.** The Capacity Credit Markets include approximately 5 percent of total capacity obligations. The MMU also analyzed the ownership of total PJM capacity in order to develop a more complete assessment of market structure for capacity. The ownership of total capacity exhibited low concentration levels throughout the year, decreasing from an HHI of 953 on January 1 to 917 on

9 For purposes of Section 5, “Capacity Markets” and Appendix E, “Capacity Markets,” these markets are identified as the PJM Capacity Market (or PJM) and the ComEd Control Zone Capacity Market (or ComEd). These markets are referred to collectively as the Capacity Markets for the regional transmission organization (RTO).

December 31. The highest market share declined from 21.6 percent to 16.6 percent. There was a single pivotal supplier throughout the year, meaning that the capacity of the largest supplier was always required in order to meet the capacity obligation.

Supply and Demand

- **Phase 4.** From January through April 2005, unforced capacity and obligations remained relatively constant in the PJM Capacity Market as compared to Phase 3. Average unforced capacity rose by 2,123 MW or 2.0 percent to 110,545 MW. Average load obligations climbed by 1,295 MW or 1.3 percent to 100,201 MW or 10,344 MW less than average unforced capacity. Overall Capacity Credit Market transactions increased by 18.7 percent from Phase 3. Daily Capacity Credit Market volumes increased by 44.7 percent, while Monthly and Multimonthly Capacity Credit Market volumes increased by 16.4 percent and 10.7 percent, respectively.

- **Phase 5.** From May through December 2005, unforced capacity and obligations increased with Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Average unforced capacity rose 35.6 percent to 149,888 MW. Average load obligation climbed 39.5 percent to 139,736 MW. Overall Capacity Credit Market transactions increased by 22.0 percent from Phase 4. Daily Capacity Credit Market volumes increased by 9.3 percent, while Monthly and Multimonthly Capacity Credit Market volumes increased by 35.7 percent and 23.8 percent, respectively.

External and Internal Capacity Transactions

- **Phase 4.** From January through April 2005, imports averaged 5,855 MW, which was a decrease of 537 MW or 8.4 percent from the Phase 3 average of 6,392 MW. Exports averaged 3,953 MW, which was an increase of 742 MW or 23.1 percent from the Phase 3 average of 3,211 MW. Average net exchange decreased 1,279 MW or 40.2 percent to 1,902 MW from the Phase 3 average of 3,181 MW. Internal bilateral transactions averaged 91,880 MW, which was an increase of 14,712 MW or 19.1 percent from the 77,168 MW average for Phase 3.

- **Phase 5.** From May through December 2005, imports averaged 4,208 MW, which was a decrease of 1,647 MW or 28.1 percent from the Phase 4 average. Exports averaged 4,856 MW, which was an increase of 903 MW or 22.8 percent from the Phase 4 average. Average net exchange decreased 2,550 MW or 134.1 percent to -648 MW from the Phase 4 average of 1,902 MW. These changes were the result of the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Internal bilateral transactions averaged 150,597 MW, which was an increase of 58,717 MW or 63.9 percent from the average for Phase 4. This increase was the result of Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market.

Active Load Management (ALM Credits)

- **Phase 4.** From January through April 2005, ALM credits in the PJM Capacity Market averaged 1,654 MW, down less than 1 percent from 1,662 MW in Phase 3.

- **Phase 5.** From May through December 2005, ALM credits in the PJM Capacity Market averaged 1,993 MW, an increase of 339 MW or 20.5 percent from Phase 4. This increase was attributable to the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1, 2005, as the mandatory interruptible load (MIL) credits in ComEd were converted to ALM credits in PJM.

Market Performance in the PJM Capacity Market

Capacity Credit Market Volumes and Prices

- **Phase 4.** From January through April 2005, total PJM Capacity Credit Market transactions averaged 5,649 MW (5.6 percent of obligation), which was 888 MW higher than the Phase 3 average (4.8 percent of obligation). Total PJM Capacity Credit Market prices averaged $7.72 per MW-day, which was $2.81 per MW-day less than the Phase 3 average.

- **Phase 5.** From May through December 2005, total PJM Capacity Credit Market transactions averaged 6,892 MW (4.9 percent of obligation), which was 1,243 MW higher than the Phase 4 average. Total PJM Capacity Credit Market prices averaged $5.47 per MW-day, which was $2.25 per MW-day less than the Phase 4 average.

- **Calendar Years 1999 through 2005.** Daily Capacity Market volume declined from 2.5 percent of average obligation in 2000 to 1.2 percent in 2005.[10] Monthly and Multimonthly Capacity Market volume increased from 3.0 percent of obligation in 2000 to 3.9 percent of average obligation in 2005. Capacity Market prices increased from 1999 through 2001 and have declined and remained relatively stable since 2001 with the exception of the summer of 2004.

ComEd Capacity Market

Market Structure for the ComEd Capacity Market

Ownership Concentration

- **June 2004 through May 2005.** Structural analysis of the ComEd Capacity Credit Market found that its Monthly and Multimonthly Markets exhibited high levels of concentration.

- **Total Capacity.** The ComEd Capacity Credit Markets include about 6 percent of total ComEd capacity obligations. The MMU also analyzed total ComEd capacity in order to develop a more complete assessment of market structure for capacity. The ownership of total capacity exhibited high concentration levels throughout the year, with HHI declining from 4525 on June 1, 2004, to 4070 on May 31, 2005, and with the maximum market share declining from 64.2 percent to 59.8 percent and RSI below 1.0 throughout the year, indicating the presence of a single pivotal supplier. The presence of a single pivotal supplier means that the capacity of the largest supplier was always required in order to meet the capacity obligation.

10 The year 2000 is used as the base year because it was the first full calendar year for which unforced capacity was used rather than installed capacity.

Supply and Demand

- **June 2004 through May 2005.** ComEd electricity distribution companies (EDCs) together had an 81.6 percent market share of load obligation. During this period, capacity resources exceeded capacity obligations in the ComEd Capacity Market every month, resulting in an average net excess of 6,261 MW, or 31.7 percent of average obligation for the period.

External and Internal Capacity Transactions

- **June 2004 through May 2005.** The ComEd Control Zone was a net exporter of capacity resources, with exports increasing from 747 MW on June 1 to 2,289 MW on May 31. Almost half of the increase was the result of increased exports to the PJM Capacity Market. Imports remained relatively constant. Internal bilateral transactions decreased by 6,361 MW on October 1 due to the lower interval peak for the October to December period.

Market Performance in the ComEd Capacity Market

Capacity Credit Market Volumes and Prices

- **June 2004 through May 2005.** Total ComEd Capacity Credit Market transactions averaged 1,229 MW, which was 6.2 percent of load obligation. Prices averaged $23.99 per MW-day.

Generator Performance

From 1996 to 2001, the average, PJM equivalent demand forced outage rate (EFORd) declined, reaching 4.6 percent in 2001, but then increased to 5.2 percent in 2002, 7.0 percent in 2003 and 8.0 percent in 2004.[11] In 2005, the average PJM EFORd decreased to 7.3 percent. The decrease in EFORd from 2004 to 2005 was the result of decreased forced outage rates across all unit types with the exception of combustion turbines. These forced outage rates are for the PJM Mid-Atlantic Region and the AP Control Zone only. The forced outage rate in 2005 was 6.5 percent for all zones within the PJM Control Area.[12]

Conclusion

The PJM Market Monitoring Unit (MMU) analyzed key measures of PJM Capacity Market and of ComEd Capacity Market structure and performance for calendar year 2005 and for the period from June 2004 through May 2005 for ComEd, including concentration ratios, prices, outage rates and reliability. Given the basic features of market structure in both the PJM and ComEd Capacity Markets, including high levels of concentration, the relatively small number of nonaffiliated LSEs, the capacity-deficiency penalty structure facing LSEs, supplier knowledge of the penalty structure and supplier knowledge of aggregate market demand if not individual LSE demand, the MMU concludes that the potential for the exercise of market power is high. Market power is endemic to the existing structure of PJM Capacity Markets.

11 As a general matter, the current year EFORd data reported in prior state of the market reports may be revised based on final data submitted after the publication of the report as final EFORd data are not available until after the publication of the reports.

12 In some cases, data for the AEP, DAY, DLCO, Dominion and ComEd Control Zones may be incomplete for the years 2004 and 2005. Only data that have been reported to PJM were used.

The analysis of capacity markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis also examines participant behavior in the context of market structure. In a competitive market structure, market participants are constrained to behave competitively. In a competitive market structure, competitive behavior is profit maximizing behavior. Finally, the analysis examines market performance results. The actual performance of the market, measured by price and the relationship between price and marginal cost, results from the interaction of these elements. For example, at times market participants behave in a competitive manner even within a noncompetitive market structure. This may result from the relationship between supply and demand and the degree to which one or more suppliers are singly or jointly pivotal even in a highly concentrated market. This may also result from a conscious choice by market participants to behave in a competitive manner based on perceived regulatory scrutiny or other reasons, even when the market structure itself does not constrain behavior.

The MMU found serious market structure issues, but no exercise of market power during these time periods. The behavior of market participants in the context of the market structure and the supply and demand fundamentals offset these market structure issues in the PJM Capacity Market in 2005. The PJM Capacity Market results were competitive during 2005. The ComEd Capacity Market results were reasonably competitive for the 12-month period from June 2004 through May 2005. Market power remains a serious concern for the MMU in the PJM Capacity Market based on market structure conditions in this market.

Market Structure for the PJM Capacity Market

The PJM Capacity Markets continued to evolve during Phases 4 and 5 of calendar year 2005, with the integrations of DLCO, Dominion and ComEd on the first days of January, May and June, respectively. The MMU analyzed capacity ownership concentration, internal sources of supply and demand, capacity credit transactions, internal and external bilateral capacity transactions and load management activity.

Ownership Concentration

Ownership concentration is assessed using market shares, concentration ratios and residual supply indices as measures. Concentration ratios are a summary measure of market share, a key element of market structure.[13] The Residual Supply Index (RSI) is a measure of the extent to which one or more generation owners are pivotal suppliers in a market.

High Herfindahl-Hirschman Index (HHI) concentration ratios mean that a comparatively small number of sellers dominate a market, while low concentration ratios mean that a larger number of sellers shares market sales more equally. Concentration measures must be applied carefully in assessing the competitiveness of markets. Low aggregate market concentration ratios do not establish that a market is competitive, that market participants cannot exercise market power or that concentration is not high in particular geographic market areas. High aggregate market concentration ratios do, however, indicate an increased potential for market participants to exercise market power.

The RSI measure recognizes that market shares and concentration ratios do not measure the extent to which an owner's generation facilities are pivotal to meeting demand. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. When a generation owner or owners are pivotal, they have the ability to affect market price, regardless of market

13 See Section 2, "Energy Market, Part 1," for a more detailed discussion of concentration ratios and the HHI and of the calculation of the Residual Supply Index.

share. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.0 for a single generation owner clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power. For example, suppliers can be jointly pivotal. If the RSI is greater than 1.0, the supply of the specific generation owner is not needed to meet market demand and that generation owner has a reduced ability to unilaterally influence market price. If the RSI is less than 1.0, the supply owned by the specific generation owner is needed to meet market demand and the generation owner is a pivotal supplier with a significant ability to influence prices.

The MMU analyzed both HHI and RSI for PJM Capacity Markets during Phases 4 and 5 of calendar year 2005.

Phase 4

The HHI analysis indicates that, on average, the PJM Capacity Credit Markets in Phase 4 exhibited low levels of concentration in the Daily Capacity Credit Market and moderate levels of concentration in the Monthly and Multimonthly Capacity Credit Markets.[14] As shown in Table 5-1 and Table 5-2, HHIs for the Daily Capacity Credit Market averaged 964 during this period, with a maximum of 2660 and a minimum of 824 (four firms with equal market shares would result in an HHI of 2500). The highest market share for any entity in a daily auction was 49.1 percent, while two of 120 daily auctions (1.7 percent) had an HHI greater than 1800. HHIs for the longer term Monthly and Multimonthly Capacity Credit Markets averaged 1705, with a maximum of 2954 and a minimum of 841 (three firms with equal market shares would result in an HHI of 3333). The highest market share for any entity in a monthly/multimonthly auction was 50.6 percent, while eight out of 23 monthly/multimonthly auctions (34.8 percent) had an HHI greater than 1800.

The RSI analysis indicates that, while there were no significant pivotal supplier issues in the Daily Capacity Credit Market in PJM for Phase 4, such issues did exist in the Monthly and Multimonthly Markets for this period. Table 5-3 and Table 5-4 show RSI values for the Daily Capacity Credit Market Auctions and the Monthly and Multimonthly Capacity Credit Market Auctions for the PJM Capacity Market. The RSI results for the Daily Capacity Credit Market indicate that the average one pivotal supplier RSI level for Phase 4 was 5.03. The one pivotal RSI fell below 1.0 in none of the 120 daily auctions, and there were no daily auctions with three or fewer jointly pivotal suppliers. The one pivotal RSI results for the Monthly and Multimonthly Markets indicate that the average RSI was 1.84 with four of the 23 monthly auctions (17.4 percent) having RSI values less than 1.0, and 14 of the auctions (60.9 percent) having three or fewer jointly pivotal suppliers.

14 PJM Capacity Market results are reported by the time period during which the auction was run and not by the time period to which the auction applies.

Table 5-1 - PJM Capacity Market HHI: Calendar year 2005

Term	Statistic	Daily Market HHI	Monthly and Multimonthly Market HHI
Phase 4	Average	964	1705
	Minimum	824	841
	Maximum	2660	2954
	Highest Market Share	49.1%	50.6%
Phase 5	Average	1093	2053
	Minimum	674	1063
	Maximum	1756	5039
	Highest Market Share	37.7%	68.0%
Calendar Year	Average	1036	1865
	Minimum	674	841
	Maximum	2660	5039
	Highest Market Share	49.1%	68.0%

Table 5-2 - PJM Capacity Market HHI statistics: Calendar year 2005

Term		Daily Market	Monthly and Multimonthly Market
Phase 4	# Auctions	120	23
	# Auctions with HHI >1800	2	8
	% Auctions with HHI >1800	1.7%	34.8%
Phase 5	# Auctions	245	40
	# Auctions with HHI >1800	0	20
	% Auctions with HHI >1800	0.0%	50.0%
Calendar Year	# Auctions	365	63
	# Auctions with HHI >1800	2	28
	% Auctions with HHI >1800	0.5%	44.4%

Table 5-3 - PJM Capacity Market residual supply index (RSI): Calendar year 2005

Term	Statistic	Daily Market RSI	Monthly and Multimonthly Market RSI
Phase 4	Average	5.03	1.84
	Minimum	3.79	0.53
	Maximum	6.96	5.49
Phase 5	Average	3.27	0.68
	Minimum	1.56	0.16
	Maximum	6.19	3.13
Calendar Year	Average	4.04	1.36
	Minimum	1.56	0.16
	Maximum	6.96	5.49

Table 5-4 - PJM Capacity Market residual supply index (RSI) statistics: Calendar year 2005

Term		Daily Market	Monthly and Multimonthly Market
Phase 4	# Auctions	120	23
	# Auctions with RSI < 1.0	0	4
	% Auctions with RSI < 1.0	0.0%	17.4%
	# Auctions with <= 3 Pivotal Suppliers	0	14
	% Auctions with <= 3 Pivotal Suppliers	0.0%	60.9%
Phase 5	# Auctions	245	40
	# Auctions with RSI < 1.0	0	30
	% Auctions with RSI < 1.0	0.0%	75.0%
	# Auctions with <= 3 Pivotal Suppliers	0	37
	% Auctions with <= 3 Pivotal Suppliers	0.0%	92.5%
Calendar Year	# Auctions	365	63
	# Auctions with RSI < 1.0	0	34
	% Auctions with RSI < 1.0	0.0%	54.0%
	# Auctions with <= 3 Pivotal Suppliers	0	51
	% Auctions with <= 3 Pivotal Suppliers	0.0%	81.0%

Phase 5

The HHI analysis indicates that, on average, the PJM Capacity Credit Markets in Phase 5 exhibited moderate levels of concentration in the Daily Capacity Credit Market and high levels of concentration in the Monthly and Multimonthly Capacity Credit Markets. As shown in Table 5-1 and Table 5-2, HHIs for the Daily Capacity Credit Market averaged 1093 during this period, with a maximum of 1756 and a minimum of 674 (four firms with equal market shares would result in an HHI of 2500). The highest market share for any entity in a daily auction was 37.7 percent, while none of the 245 daily auctions had an HHI greater than 1800. HHIs for the longer term Monthly and Multimonthly Capacity Credit Markets averaged 2053, with a maximum of 5039 and a minimum of 1063 (three firms with equal market shares would result in an HHI of 3333). The highest market share for any entity in a monthly/multimonthly auction was 68.0 percent, while 20 out of 40 monthly/multimonthly auctions (50.0 percent) had an HHI greater than 1800.

The RSI analysis indicates that while there were no significant pivotal supplier issues in the Daily Capacity Credit Market in PJM for Phase 5, such issues did exist in the Monthly and Multimonthly Markets for this period. Table 5-3 and Table 5-4 show single pivotal supplier RSI values for the Daily Capacity Credit Market Auctions and the Monthly and Multimonthly Capacity Credit Market Auctions for the PJM Capacity Market. The RSI results for the Daily Capacity Credit Market indicate that the average RSI level for Phase 5 was 3.27. RSI did not fall below 1.0 in any of the 245 daily auctions, and there were no daily auctions with three or fewer jointly pivotal suppliers. The RSI results for the Monthly and Multimonthly Markets indicate that the average RSI was 0.68 with 30 of the 40 monthly auctions (75.0 percent) having RSI values less than 1.0 and 37 of the auctions (92.5 percent) having three or fewer jointly pivotal suppliers.

Total Capacity

The market structure analyses presented above focused on the operation of Capacity Credit Markets which include only about 5 percent of total capacity obligations traded in PJM-operated markets. To provide a more complete assessment of competition in the PJM Capacity Market, the MMU also analyzed total capacity without regard to whether it is sold in PJM-operated markets, through bilateral agreements or self-supplied.

The market structure for total capacity in the aggregate PJM market is shown for specific dates in Table 5-5. The analysis uses capacity ownership as of January 1 (DLCO joined PJM), May 1 (Dominion joined PJM), June 1 (integration of ComEd Capacity Market) and December 31, 2005.

The analysis shows that when Dominion joined PJM on May 1, obligation and unforced capacity increased while the total capacity ownership market shares of PJM members were reduced.[15] The decrease in market shares resulted in a lower level of market concentration, reflected in the decrease of HHI from 953 to 896. The maximum market share decreased from 21.6 percent to 18.2 percent. There was a single pivotal supplier throughout the year.

When the ComEd Capacity Market was integrated into the PJM Capacity Market on June 1, obligation and unforced capacity again increased. Total capacity ownership market shares of existing PJM members decreased with the exception of Exelon Corporation, whose market share increased, reflecting ownership

15 Dominion owned capacity in PJM before May 1, so its market share increased as a result of its integration.

of capacity in both ComEd and PJM. Exelon's higher market share led to a slight increase in market concentration, shown by an increase in HHI from 896 to 901. Capacity additions by existing capacity owners after June 1 resulted in an increase in HHI from 901 to 917 on December 31.[16]

Total capacity ownership was at low concentration levels throughout the year, decreasing from 953 on January 1 to 917 on December 31. The highest market share declined from 21.6 percent to 16.6 percent. There was a single pivotal supplier throughout the year.

Table 5-5 - PJM capacity: Calendar year 2005

	01-Jan	01-May	01-Jun	31-Dec
Unforced Capacity (MW)	109,675	129,869	152,328	153,326
Obligation (MW)	99,944	118,680	142,494	142,886
HHI	953	896	901	917
Highest Market Share	21.6%	18.2%	16.4%	16.6%
RSI	0.86	0.90	0.89	0.89
Pivotal Suppliers	1	1	1	1

Supply and Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- **PJM EDC.** PJM EDCs are entities with a franchise service territory within the PJM boundaries. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** Non-PJM EDCs are electricity distribution companies whose franchise service territories lie outside of PJM boundaries.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

16 See Section 3, "Energy Market, Part 2," for a more detailed discussion of capacity additions.

Phase 4

During Phase 4, PJM EDCs and their affiliates maintained a large market share of load obligations in the PJM Capacity Market, together averaging 85.0 percent (Figure 5-1 and Table 5-6), down from the 86.1 percent for Phase 3. The combined market share for Phase 4 of LSEs not affiliated with any EDC and of non-PJM EDC affiliates averaged 15.0 percent, up from the 13.9 percent for Phase 3.

Load-serving entities can meet their load obligations through self-supply,[17] the PJM Capacity Credit Market or bilateral contracts with third parties. As shown in Table 5-7, Table 5-8 and Table 5-9, reliance on these options varied by market sector.[18] During Phase 4, PJM EDCs, some of which still owned generating assets (although as a whole not enough to meet their load obligations), self-supplied an average of 63.5 percent of their load obligations with their remaining obligations being supplied through bilateral contracts with third parties (39.8 percent) and the PJM Capacity Credit Market (0.9 percent). The self-supply percentage is down from the Phase 3 value of 64.9 percent, while the bilateral contract percentage has increased from 37.9 percent for Phase 3. In Phase 4, entities in this sector, on average, purchased more capacity credits in the PJM Capacity Credit Market or through bilateral contracts with third parties than were required to meet their obligation, resulting in an average net excess of 2,037 MW (4.2 percent of obligation) as compared to a Phase 3 average net excess of 995 MW (2.0 percent of obligation) for this sector. In Phase 3 and Phase 4, all generating affiliate sectors owned more capacity than their load obligations, were net capacity credit sellers in either the PJM Capacity Credit Market or through bilateral contracts and remained in higher net excess positions as a percentage of load obligations than the other sectors. All marketing affiliate sectors, which were net capacity credit buyers in either the PJM Capacity Credit Market or through bilateral contracts, bought slightly more capacity credits than required to meet their obligation and were in lower net excess positions than the other sectors in Phase 3 and Phase 4. Volumes and percentages of load obligations for self-supply, the Capacity Credit Market and bilateral contracts for all generating affiliate and marketing affiliate sectors were approximately the same for Phase 3 and Phase 4.

System net excess capacity can be determined using unforced capacity, capacity obligation, the sum of members' excesses and the sum of members' deficiencies. Table 5-10 and Figure 5-2 present these data for Phase 4.[19] Net excess is the net pool position, calculated by subtracting total capacity obligation from total capacity resources. Since total capacity obligation includes expected total load plus a reserve margin, a pool net excess position of zero is consistent with established reliability objectives.

17 Self-supply is defined as the unforced MW of the units owned by an entity.

18 Negative values in the "Capacity Credit Market" and in the "Net Bilateral Contracts" columns mean that a sector sold more capacity credits than it purchased for the relevant time period. A positive number means that a sector purchased more capacity credits than it sold for the relevant time period.

19 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.

During Phase 4, unforced capacity and obligations remained relatively constant in the PJM Capacity Market as compared to Phase 3. Average unforced capacity rose by 2,123 MW from 108,422 MW to 110,545 MW, an increase of 2.0 percent. Average load obligations increased 1,295 MW or 1.3 percent from 98,906 MW to 100,201 MW. During this period, capacity resources exceeded capacity obligations in PJM on every day and the daily average net excess was 10,344 MW (10.3 percent of average obligation), an increase of 829 MW from the average net excess of 9,515 MW for Phase 3 (9.6 percent of average obligation). This is considered an excess capacity position. The amount of capacity resources in PJM on any day reflects the addition of new resources, the retirement of old resources and the importing or exporting of capacity resources. These daily changes are functions of market forces. The total pool capacity obligation is set annually via an administrative process.

Figure 5-1 - PJM Capacity Market load obligation served (Percent): Calendar year 2005

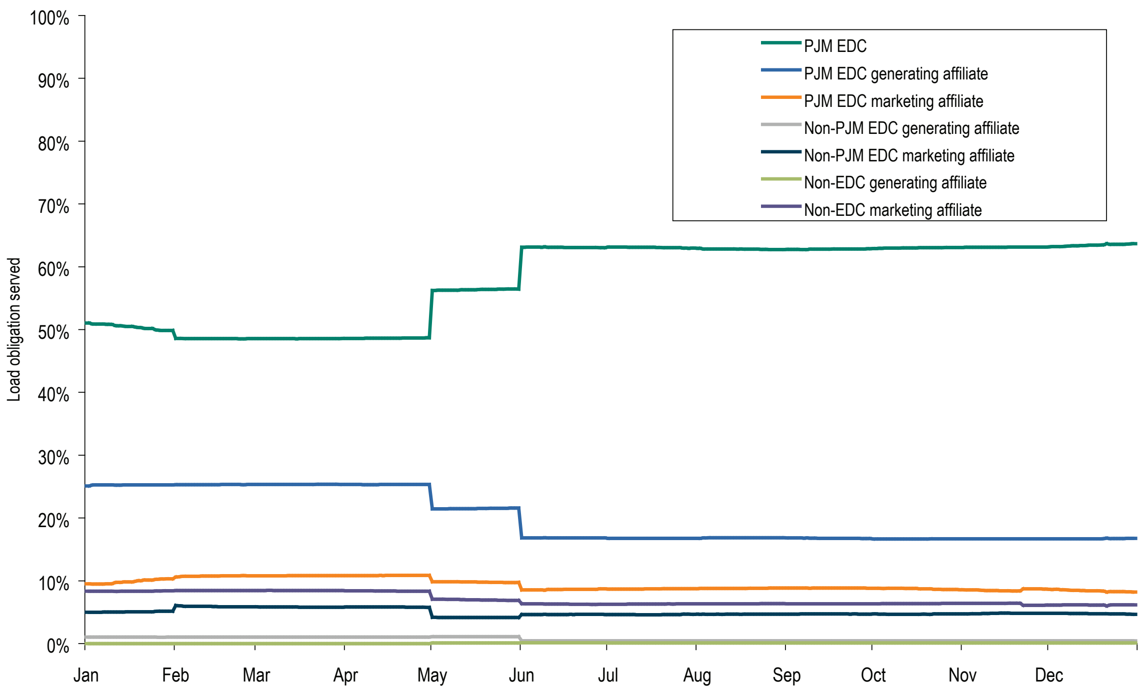


Table 5-6 - PJM Capacity Market load obligation served: Calendar year 2005

	Average Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Jan	50,489	25,269	9,879	1,025	5,063	0	8,355	100,080
Feb	48,642	25,359	10,772	1,025	5,920	0	8,465	100,183
Mar	48,664	25,404	10,841	1,026	5,830	0	8,467	100,232
Apr	48,779	25,403	10,875	1,026	5,829	0	8,400	100,312
May	66,893	25,527	11,631	1,309	4,939	125	8,275	118,699
Jun	89,798	23,945	12,259	604	6,604	175	8,958	142,343
Jul	90,088	23,943	12,437	604	6,598	162	9,001	142,833
Aug	89,750	24,066	12,572	604	6,687	162	9,059	142,900
Sep	89,917	24,009	12,656	604	6,740	162	9,081	143,169
Oct	89,925	23,787	12,452	608	6,684	164	9,092	142,712
Nov	90,097	23,817	12,177	608	6,865	164	9,015	142,743
Dec	90,563	23,857	12,005	609	6,804	164	8,777	142,779
Phase 4								
Average	49,159	25,358	10,585	1,026	5,652	0	8,421	100,201
% of Total Obligation	49.1%	25.3%	10.6%	1.0%	5.6%	0.0%	8.4%	100.0%
Phase 5								
Average	87,095	24,121	12,272	695	6,487	160	8,906	139,736
% of Total Obligation	62.3%	17.3%	8.8%	0.5%	4.6%	0.1%	6.4%	100.0%
Calendar Year								
Average	74,623	24,528	11,718	804	6,213	107	8,746	126,739
% of Total Obligation	58.9%	19.4%	9.2%	0.6%	4.9%	0.1%	6.9%	100.0%

Table 5-7 - PJM Capacity Market load obligation served by PJM EDCs and affiliates: Calendar year 2005

	PJM EDCs					PJM EDC Generating Affiliates					PJM EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	31,215	560	20,542	50,489	1,828	49,248	12	(20,329)	25,269	3,662	0	549	9,785	9,879	455
Feb	31,213	432	18,749	48,642	1,752	49,255	(334)	(20,563)	25,359	2,999	0	796	10,235	10,772	259
Mar	31,181	282	19,436	48,664	2,235	49,255	(162)	(20,535)	25,404	3,154	0	936	10,187	10,841	282
Apr	31,172	400	19,522	48,779	2,315	49,254	(240)	(19,652)	25,403	3,959	0	969	10,197	10,875	291
May	49,055	153	19,885	66,893	2,200	51,177	92	(21,980)	25,527	3,762	0	1,170	10,795	11,631	334
Jun	50,291	729	40,840	89,798	2,062	65,660	(1,650)	(37,717)	23,945	2,348	0	1,106	11,497	12,259	344
Jul	50,291	417	41,234	90,088	1,854	65,601	(2,067)	(37,491)	23,943	2,100	0	1,598	11,153	12,437	314
Aug	50,291	303	40,873	89,750	1,717	65,600	(1,775)	(37,725)	24,066	2,034	0	1,727	11,112	12,572	267
Sep	50,365	181	40,912	89,917	1,541	65,553	(1,807)	(37,943)	24,009	1,794	0	1,832	11,103	12,656	279
Oct	51,123	679	41,126	89,925	3,003	65,420	(1,486)	(38,562)	23,787	1,585	0	1,842	10,979	12,452	369
Nov	51,133	448	41,378	90,097	2,862	65,420	(1,481)	(38,793)	23,817	1,329	0	1,542	10,936	12,177	301
Dec	51,380	568	41,443	90,563	2,828	65,439	(1,767)	(38,910)	23,857	905	0	1,547	10,778	12,005	320
Phase 4															
Average	31,195	418	19,583	49,159	2,037	49,253	(177)	(20,268)	25,358	3,450	0	812	10,097	10,585	324
% of Total Obligation	63.5%	0.9%	39.8%	104.2%	4.2%	194.2%	(0.7%)	(79.9%)	113.6%	13.6%	0.0%	7.7%	95.4%	103.1%	3.1%
Phase 5															
Average	50,490	434	38,430	87,095	2,259	63,712	(1,491)	(36,116)	24,121	1,984	0	1,546	11,043	12,272	317
% of Total Obligation	58.0%	0.5%	44.1%	102.6%	2.6%	264.1%	(6.2%)	(149.7%)	108.2%	8.2%	0.0%	12.6%	90.0%	102.6%	2.6%
Calendar Year															
Average	44,146	429	32,234	74,623	2,186	58,958	(1,059)	(30,905)	24,528	2,466	0	1,305	10,732	11,718	319
% of Total Obligation	59.2%	0.6%	43.2%	103.0%	3.0%	240.4%	(4.3%)	(126.0%)	110.1%	10.1%	0.0%	11.1%	91.6%	102.7%	2.7%

Table 5-8 - PJM Capacity Market load obligation served by non-PJM EDC affiliates: Calendar year 2005

	Non-PJM EDC Generating Affiliates					Non-PJM EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	9,020	(649)	(5,316)	1,025	2,030	0	463	4,744	5,063	144
Feb	9,026	(570)	(5,572)	1,025	1,859	0	409	5,725	5,920	214
Mar	9,034	(553)	(5,830)	1,026	1,625	0	561	5,569	5,830	300
Apr	9,039	(394)	(5,740)	1,026	1,879	0	549	5,566	5,829	286
May	7,158	(315)	(3,836)	1,309	1,698	0	456	4,710	4,939	227
Jun	13,665	24	(10,037)	604	3,048	0	617	6,690	6,604	703
Jul	13,668	(97)	(10,028)	604	2,939	0	706	6,467	6,598	575
Aug	13,668	(161)	(9,954)	604	2,949	0	545	6,526	6,687	384
Sep	13,668	(135)	(10,059)	604	2,870	0	573	6,655	6,740	488
Oct	13,555	(299)	(10,151)	608	2,497	0	532	7,121	6,684	969
Nov	13,553	(200)	(10,191)	608	2,554	0	505	7,313	6,865	953
Dec	13,553	(213)	(10,174)	609	2,557	0	662	7,305	6,804	1,163
Phase 4										
Average	9,030	(542)	(5,614)	1,026	1,848	0	497	5,392	5,652	237
% of Total Obligation	880.5%	(52.8%)	(547.4%)	280.3%	180.3%	0.0%	8.8%	95.4%	104.2%	4.2%
Phase 5										
Average	12,801	(175)	(9,294)	695	2,637	0	575	6,595	6,487	683
% of Total Obligation	1841.8%	(25.2%)	(1337.2%)	479.4%	379.4%	0.0%	8.9%	101.7%	110.6%	10.6%
Calendar Year										
Average	11,561	(296)	(8,084)	804	2,377	0	549	6,199	6,213	535
% of Total Obligation	1438.5%	(36.8%)	(1005.9%)	395.8%	295.8%	0.0%	8.8%	99.8%	108.6%	8.6%

Table 5-9 - PJM Capacity Market load obligation served by non-EDC affiliates: Calendar year 2005

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	18,898	(991)	(16,804)	0	1,103	0	56	8,643	8,355	344
Feb	19,234	(890)	(15,906)	0	2,438	0	157	8,801	8,465	493
Mar	19,271	(1,157)	(15,795)	0	2,319	0	94	8,886	8,467	513
Apr	19,268	(1,275)	(15,824)	0	2,169	0	(9)	8,878	8,400	469
May	20,502	(1,676)	(16,228)	125	2,473	0	120	8,678	8,275	523
Jun	23,954	(1,135)	(21,783)	175	861	0	308	9,249	8,958	599
Jul	23,975	(922)	(21,539)	162	1,352	0	364	9,058	9,001	421
Aug	23,973	(534)	(21,860)	162	1,417	0	(105)	9,587	9,059	423
Sep	23,971	(1,072)	(21,358)	162	1,379	0	427	9,203	9,081	549
Oct	24,081	(1,299)	(20,457)	164	2,161	0	30	9,407	9,092	345
Nov	24,048	(830)	(20,395)	164	2,659	0	16	9,238	9,015	239
Dec	23,809	(857)	(20,196)	164	2,592	0	60	8,888	8,777	171
Phase 4										
Average	19,165	(1,081)	(16,089)	0	1,995	0	73	8,801	8,421	453
% of Total Obligation	NA	NA	NA	NA	NA	0.0%	0.9%	104.5%	105.4%	5.4%
Phase 5										
Average	23,534	(1,041)	(20,469)	160	1,864	0	151	9,163	8,906	408
% of Total Obligation	14724.6%	(651.3%)	(12806.8%)	1266.5%	1166.5%	0.0%	1.7%	102.9%	104.6%	4.6%
Calendar Year										
Average	22,097	(1,054)	(19,029)	107	1,907	0	126	9,044	8,746	424
% of Total Obligation	20597.9%	(982.7%)	(17737.4%)	1877.8%	1777.8%	0.0%	1.4%	103.4%	104.8%	4.8%

Phase 5

As shown in Figure 5-1 and Table 5-6, during Phase 5, PJM EDCs and their affiliates increased their market share of load obligations in the PJM Capacity Market, averaging 88.4 percent, an increase of 3.4 percent over Phase 4. This increase was attributable to Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. The combined market share for Phase 5 of LSEs not affiliated with any EDC and of non-PJM EDCs and their affiliates averaged 11.6 percent, which was down from the 15.0 percent for Phase 4.

Table 5-7, Table 5-8 and Table 5-9 show that during Phase 5, all market sectors were in net excess positions as they had been in Phase 4. PJM EDCs self-supplied an average of 58.0 percent of their load obligations with their remaining obligations being supplied almost entirely through bilateral contracts with third parties (44.1

percent). While Dominion's integration on May 1 increased the self-supplied average volume from 31,172 MW in April to 49,055 MW in May, the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1 decreased the percentage self-supplied by EDCs. Commonwealth Edison Company (an EDC in the ComEd Control Zone) was the major electric distribution company in this market. Having spun off its generating assets to an affiliate, Exelon Generation Company, LLC (ExGen), the company met its entire capacity obligation through bilateral transactions with this affiliate.[20] (See Table 5-18 for ComEd EDC values.)

As shown in Table 5-11 and Figure 5-2, during Phase 5 unforced capacity and obligations increased with Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Average unforced capacity climbed 39,343 MW to 149,888 MW, an increase of 35.6 percent. Average load obligation increased 39,535 MW or 39.5 percent to 139,736 MW. Capacity resources exceeded capacity obligations in PJM on every day by a daily average of 10,152 MW (7.3 percent of obligations), which was a decrease of 192 MW or 1.9 percent from the average net excess during Phase 4. This decrease was attributable to a decrease in imports and an increase in exports resulting from the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Dominion joining PJM on May 1 had no significant impact on net excess. The increases in unforced capacity and obligation were also attributable to ComEd as well as Dominion.

Table 5-10 - PJM capacity summary (MW): Phase 4

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	119,402	723	118,325	120,586
Unforced Capacity	110,545	761	109,351	111,725
Obligation	100,201	94	99,944	100,353
Sum of Excess	10,345	679	9,226	11,442
Sum of Deficiency	1	8	0	39
Net Excess	10,344	681	9,226	11,442
Imports	5,855	359	5,558	6,461
Exports	3,953	335	3,397	4,606
Net Exchange	1,902	659	964	2,992
Internal Unit-Specific Transactions	11,788	77	11,737	11,920
Internal Capacity Credit Transactions	80,092	1,071	78,740	82,011
Total Internal Bilateral Transactions	91,880	1,098	90,492	93,748
Daily Capacity Credits	1,427	91	1,070	1,675
Monthly Capacity Credits	900	370	651	1,523
Multimonthly Capacity Credits	3,322	326	2,810	3,639
All Capacity Credits	5,649	153	5,076	5,937
ALM Credits	1,654	4	1,653	1,669

20 Exelon Corporation, Annual Report (Form 10-K), at 6 (February 23, 2005).

Table 5-11 - PJM capacity summary (MW): Phase 5

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	160,322	7,769	139,942	163,951
Unforced Capacity	149,888	7,644	129,869	153,746
Obligation	139,736	8,026	118,680	143,260
Sum of Excess	10,152	825	8,665	11,270
Sum of Deficiency	0	0	0	0
Net Excess	10,152	825	8,665	11,270
Imports	4,208	609	3,728	5,665
Exports	4,856	701	3,618	5,746
Net Exchange	(648)	1,084	(1,655)	2,047
Internal Unit-Specific Transactions	17,540	2,185	11,920	19,064
Internal Capacity Credit Transactions	133,057	13,152	98,520	140,859
Total Internal Bilateral Transactions	150,597	15,277	110,440	158,940
Daily Capacity Credits	1,560	373	1,025	2,455
Monthly Capacity Credits	1,221	253	699	1,539
Multimonthly Capacity Credits	4,111	306	3,639	4,497
All Capacity Credits	6,892	633	6,035	8,103
ALM Credits	1,993	130	1,653	2,065

External and Internal Capacity Transactions

PJM capacity resources may be traded bilaterally within and outside of PJM.

External Capacity Transactions

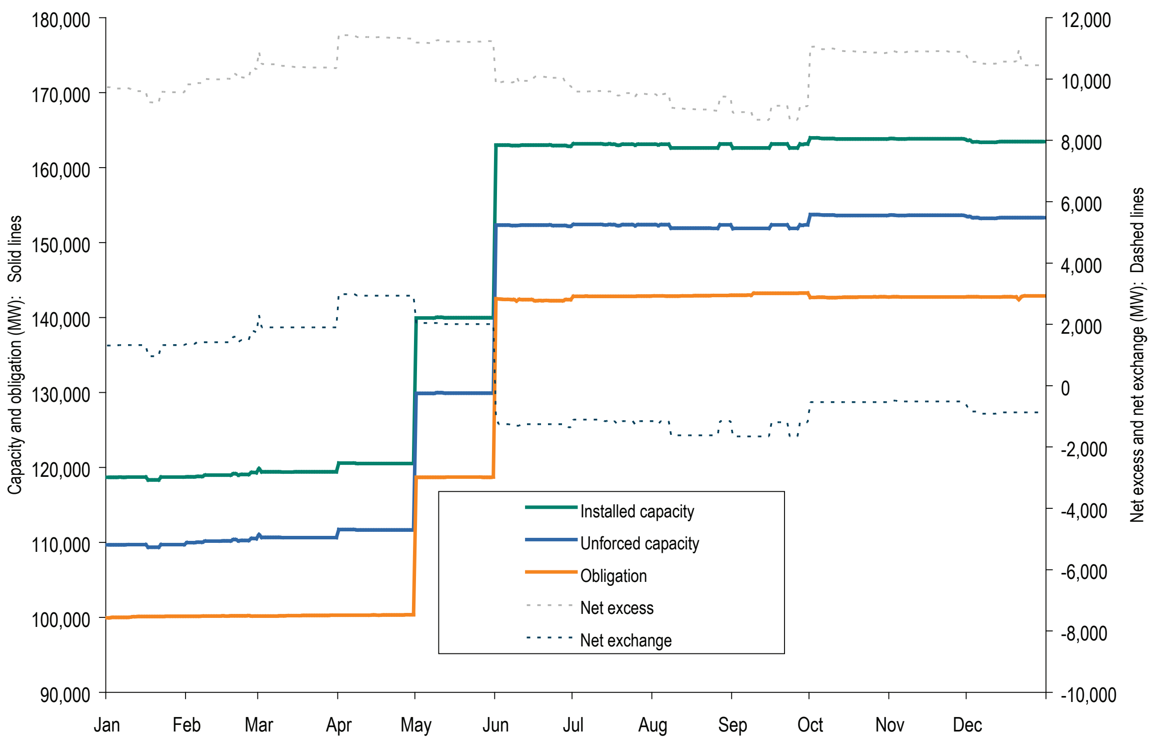
External bilateral transactions include imports of capacity resources from other control areas and exports of capacity resources to control areas outside of PJM.[21] Net exchange is equal to imports less exports.

Phase 4

As shown in Table 5-10 and Figure 5-3, Capacity Market participants' external purchases (imports) of capacity resources were relatively flat through Phase 4, averaging 5,855 MW, which was a decrease of 537 MW or 8.4 percent from the average of 6,392 MW for Phase 3.

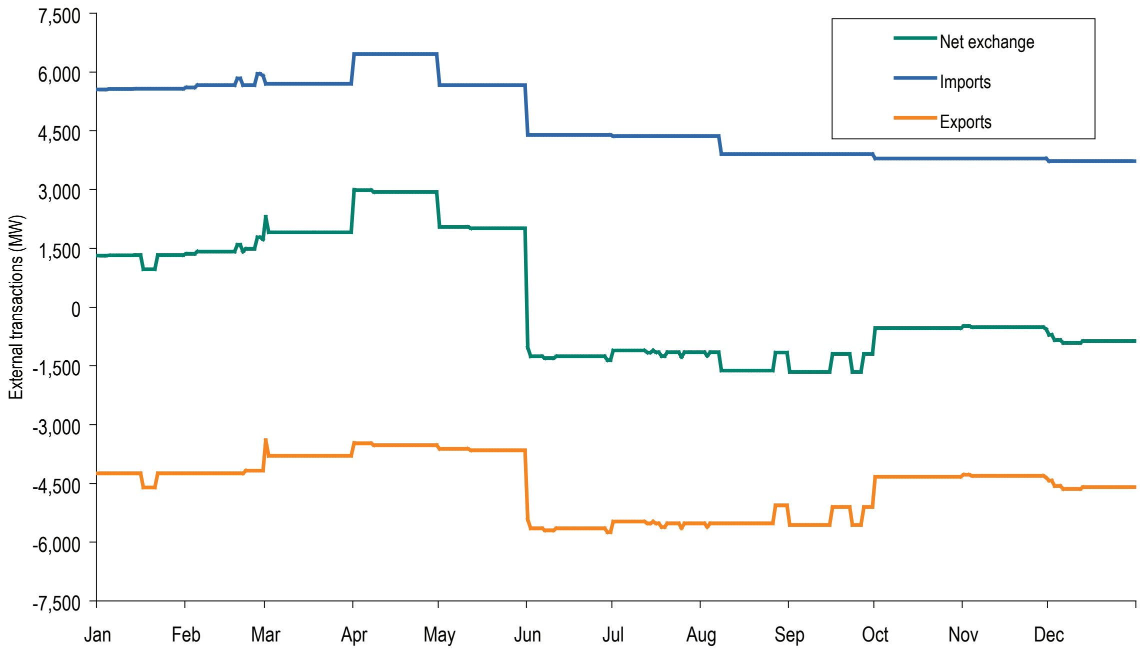
During Phase 4, an average of 3,953 MW of capacity resources was exported from the PJM Capacity Market, which was an increase of 742 MW or 23.1 percent from the average of 3,211 MW for Phase 3. The result was an average net exchange of 1,902 MW of capacity resources for Phase 4, which was a decrease of 1,279 MW or 40.2 percent from the average net exchange of 3,181 MW for Phase 3.

Figure 5-2 - Capacity obligation for the PJM Capacity Market: Calendar year 2005



21 The sink (destination) of exports cannot be identified since these data are not required from member companies.

Figure 5-3 - External PJM Capacity Market transactions: Calendar year 2005



Phase 5

Dominion's integration into PJM on May 1 had no significant impact on imports, exports or net exchange. However, the impact of the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1 was significant. What had been exports from the ComEd Capacity Market and imports into PJM became internal transactions. What had been exports from the ComEd Capacity Market into control areas other than PJM were added to total PJM exports. As a result, imports into the PJM market declined; exports from the PJM market increased (i.e., values became more negative), and on June 1 net exchange fell by 3,043 MW, which was the sum of the two changes.[22] (See Figure 5-3.)

Capacity owners' external purchases (imports) of capacity resources during Phase 5 averaged 4,208 MW, which was a decrease of 1,647 MW or 28.1 percent from the import average for Phase 4. (See Table 5-11 and Figure 5-3.)

During Phase 5, an average of 4,856 MW of capacity resources was exported from the PJM Capacity Market, which was an increase of 903 MW or 22.8 percent from the export average for Phase 4. The result was an average net exchange of -648 MW of capacity resources for Phase 5, which was a decrease of 2,550 MW or 134.1 percent from the average net exchange of 1,902 MW for Phase 4.

22 This MW value is the daily change between May 31 and June 1. Daily changes are only reflected in figures. Tables generally show period averages or values for specific dates.

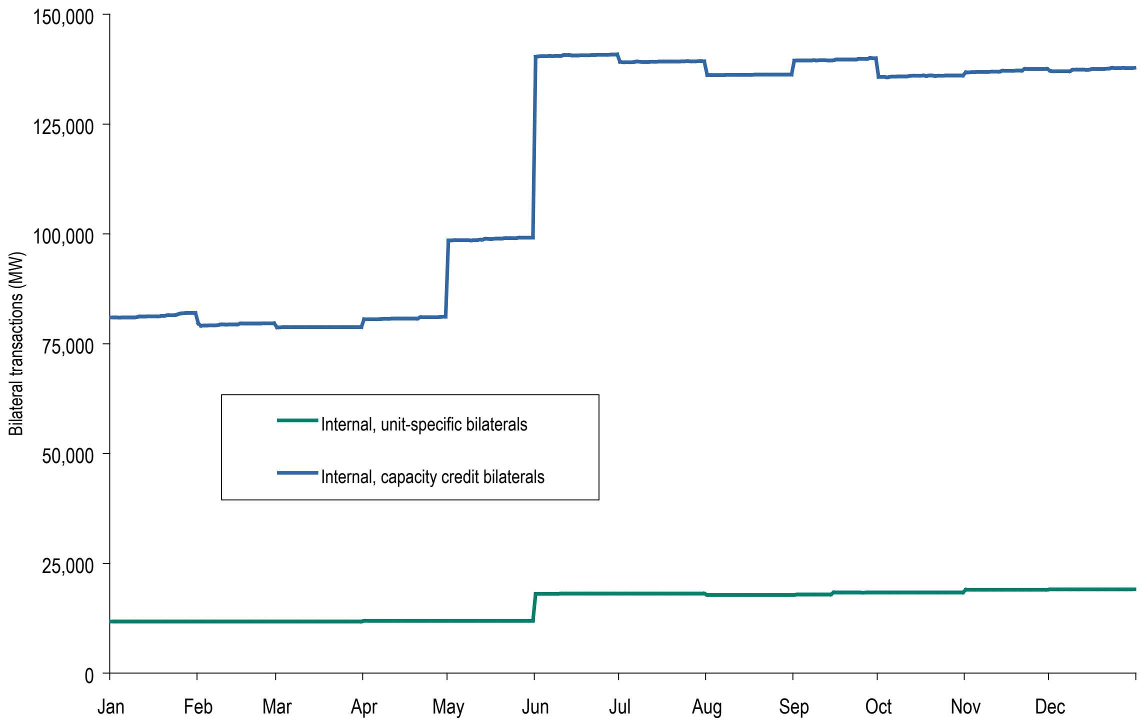
Internal Bilateral Transactions

Internal bilateral transactions are agreements between two parties for the buying and selling of capacity credits within PJM.[23] Unit-specific transactions are for capacity credits from a specific generating unit while capacity credit transactions are for non-unit-specific capacity credits. Both types of transactions may be traded multiple times between parties with the result that transaction volume can exceed obligation.

Phase 4

During Phase 4, internal, unit-specific transactions for the PJM Capacity Market averaged 11,788 MW, which was a decrease of 809 MW or 6.4 percent from the average of 12,597 MW for Phase 3. (See Table 5-10 and Figure 5-4.) Internal capacity credit transactions in Phase 4 averaged 80,092 MW, which was an increase of 15,521 MW or 24.0 percent from the average of 64,571 MW for Phase 3. Total internal bilateral transactions in Phase 4 averaged 91,880 MW, an increase of 14,712 MW or 19.1 percent from the 77,168 MW average for Phase 3.

Figure 5-4 - Internal bilateral PJM Capacity Market transactions: Calendar year 2005



23 As of December 31, 2005, only volumes from internal bilateral transactions are reported to PJM. Pricing data are not required from member companies.

Phase 5

During Phase 5, PJM's internal bilateral transactions rose. As noted above, the impact of the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1 was significant. What had been exports from the ComEd Capacity Market and imports into PJM became internal transactions. The increase in internal bilateral transactions on June 1 was 47,334 MW.[24] As a result, total internal bilateral transactions in Phase 5 averaged 150,597 MW, which was an increase of 58,717 MW or 63.9 percent from the Phase 4 average.

Internal, unit-specific transactions for the PJM Capacity Market averaged 17,540 MW, which was an increase of 5,752 MW or 48.8 percent from the average for Phase 4. (See Table 5-11 and Figure 5-4.) Internal capacity credit transactions in Phase 5 averaged 133,057 MW, an increase of 52,965 MW or 66.1 percent from the Phase 4 average.

Active Load Management (ALM) Credits

Phase 4

Active load management (ALM) reflects the ability of individual customers, under contract with their LSE, to reduce specified amounts of load during an emergency. ALM credits, measured in MW of curtailable load, reduce LSE capacity obligations.

During Phase 4, ALM credits in the PJM Capacity Market averaged 1,654 MW, down less than 1 percent from 1,662 MW in Phase 3. (See Table 5-10.)

Phase 5

During Phase 5, ALM credits in the PJM Capacity Market averaged 1,993 MW, an increase of 339 MW or 20.5 percent from Phase 4. This increase was attributable to the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1, 2005, as the mandatory interruptible load (MIL) credits in ComEd were converted to ALM credits in PJM. (See Table 5-11.)

24 This MW value is the daily change between May 31 and June 1. Daily changes are only reflected in figures. Tables generally show period averages or values for specific dates.

Market Performance in the PJM Capacity Market

Capacity Credit Market Volumes and Prices

Phase 4

During 2005, PJM operated Daily, Monthly and Multimonthly Capacity Credit Markets. Figure 5-5 and Table 5-12 show prices and volumes for the calendar year 2005 in PJM's Daily and longer term Capacity Credit Markets. During Phase 4, the Daily Capacity Credit Market averaged 1,427 MW of transactions, representing 1.4 percent of the period's 100,201 MW average capacity obligation. The Phase 4 average transaction volume was 441 MW greater than the Phase 3 average of 986 MW, which had been 1.0 percent of the average capacity obligations for Phase 3. The Monthly and Multimonthly Capacity Credit Markets averaged 4,222 MW of transactions, which was 4.2 percent of the average capacity obligations for Phase 4 and 447 MW higher than the Phase 3 average of 3,775 MW, which was 3.8 percent of the average capacity obligations for Phase 3.

The volume-weighted, average price for Phase 4 was $0.04 per MW-day in the Daily Capacity Credit Market and $10.32 per MW-day in the Monthly and Multimonthly Capacity Credit Markets. The volume-weighted, average price for all Capacity Credit Markets was $7.72 per MW-day.[25] Prices in the Daily Capacity Credit Market during Phase 4 were $0.36 lower than the Phase 3 price of $0.40. Prices in the Monthly and Multimonthly Markets were $2.85 lower than the Phase 3 price of $13.17.

Phase 5

The PJM Daily Capacity Credit Market averaged 1,560 MW of transactions, or 1.1 percent of the average capacity obligations for Phase 5. (See Figure 5-5 and Table 5-12.) Trading in the Daily Capacity Credit Market increased by 133 MW compared to activity in Phase 4. The PJM Monthly and Multimonthly Capacity Credit Markets averaged 5,332 MW of transactions, or 3.8 percent of the average capacity obligations for Phase 5. Trading in the Monthly and Multimonthly Capacity Credit Markets increased by 1,110 MW compared to activity in Phase 4.

The volume-weighted, average price for Phase 5 was $0.21 per MW-day in the Daily Capacity Credit Market and $7.01 per MW-day in the Monthly and Multimonthly Capacity Credit Markets. The volume-weighted, average price for all Capacity Credit Markets was $5.47 per MW-day. Prices in the Daily Capacity Credit Market during Phase 5 were $0.17 higher than Phase 4, while prices in the Monthly and Multimonthly Markets were $3.31 lower for the period.

Calendar Years 1999 through 2005

Figure 5-6 and Table 5-13 show prices and volumes in PJM's Daily and longer term Capacity Credit Markets from June 1999 through December 2005.[26] Since the interval system was introduced in July 2001, overall volume in the Capacity Credit Markets has increased, prices have declined and remained relatively stable with the exception of the summer of 2004, and capacity obligations have almost tripled. The share of load

25 Graph and average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.
26 After June 1, 1999, the PJM Capacity Credit Market was based on unforced capacity. Before this date, the market had been based on installed capacity.

obligation traded in the PJM Daily Capacity Market has declined while the share of load obligation traded in Monthly and Multimonthly Capacity Markets has increased. Daily Capacity Market volume declined from 2.5 percent of average obligation in 2000 to 1.2 percent in 2005. Monthly and Multimonthly Capacity Market volume increased from 3.0 percent of obligation in 2000 to 3.9 percent of average obligation in 2005.

Figure 5-5 - PJM Daily and Monthly Capacity Credit Market (CCM) performance: Calendar year 2005

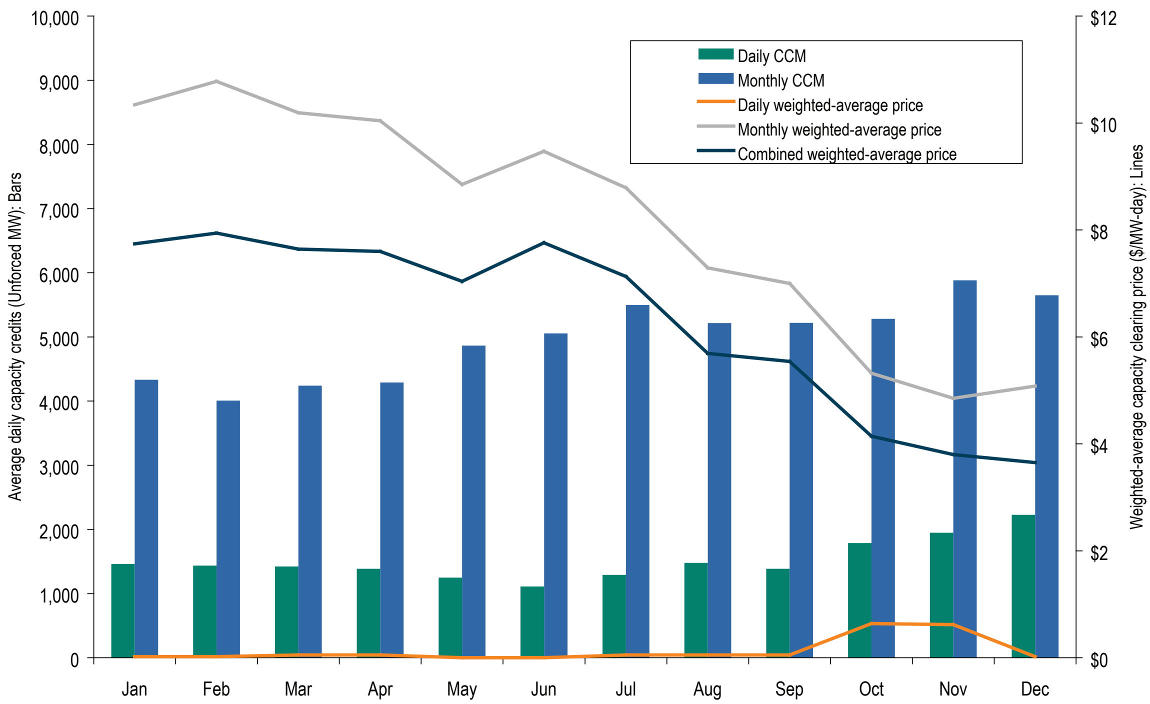


Table 5-12 - PJM Capacity Credit Markets: Calendar year 2005

	Average Daily Capacity Credits (MW)			Weighted-Average Price ($ per MW-day)		
	Daily Capacity Credit Market	Monthly and Multimonthly Capacity Credit Market	Combined Markets	Daily Capacity Credit Market	Monthly and Multimonthly Capacity Credit Market	Combined Markets
Jan	1,461	4,333	5,794	$0.02	$10.34	$7.74
Feb	1,436	4,006	5,442	$0.02	$10.78	$7.94
Mar	1,423	4,240	5,663	$0.05	$10.19	$7.64
Apr	1,387	4,290	5,677	$0.05	$10.04	$7.60
May	1,249	4,864	6,113	$0.00	$8.85	$7.04
Jun	1,112	5,053	6,165	$0.00	$9.47	$7.76
Jul	1,290	5,497	6,787	$0.05	$8.79	$7.13
Aug	1,476	5,216	6,692	$0.05	$7.29	$5.69
Sep	1,387	5,219	6,606	$0.05	$7.00	$5.54
Oct	1,787	5,282	7,069	$0.64	$5.32	$4.14
Nov	1,948	5,883	7,831	$0.62	$4.85	$3.80
Dec	2,225	5,648	7,873	$0.02	$5.08	$3.65
Average						
Phase 4	1,427	4,222	5,649	$0.04	$10.32	$7.72
Phase 5	1,560	5,332	6,892	$0.21	$7.01	$5.47
Calendar Year	1,516	4,968	6,484	$0.15	$7.94	$6.12

Figure 5-6 - PJM Daily and Monthly Capacity Credit Market (CCM) performance: June 1999 through December 2005

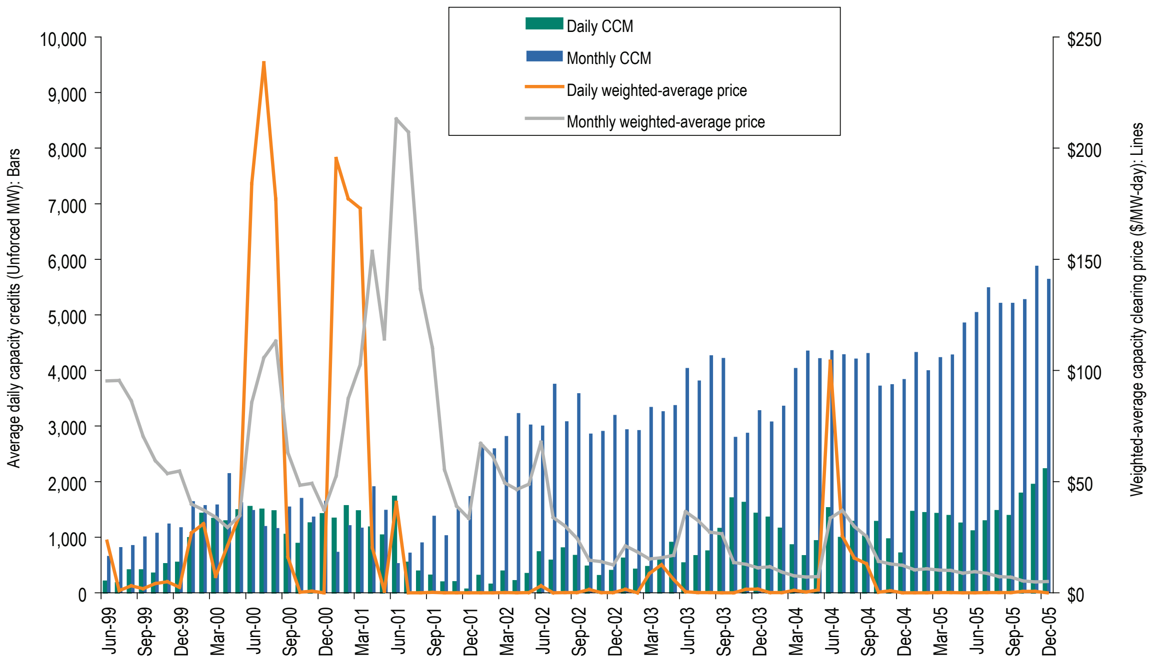


Table 5-13 - PJM Capacity Credit Markets: Calendar years 1999[27] through 2005[28]

	Average Daily Capacity Credits						Weighted-Average Price ($ per MW-day)		
	Daily Capacity Credit Market (MW)	Percent of Obligation	Monthly and Multimonthly Capacity Credit Market (MW)	Percent of Obligation	Combined Markets (MW)	Percent of Obligation	Daily Capacity Credit Market	Monthly and Multimonthly Capacity Credit Market	Combined Markets
1999	374	0.7%	981	1.9%	1,355	2.6%	$4.69	$70.36	$52.24
2000	1,304	2.5%	1,561	3.0%	2,865	5.4%	$69.39	$53.16	$60.55
2001	829	1.5%	1,197	2.2%	2,026	3.7%	$87.98	$100.43	$95.34
2002	450	0.8%	3,066	5.3%	3,516	6.1%	$0.59	$38.21	$33.40
2003	907	1.4%	3,436	5.2%	4,343	6.6%	$2.14	$21.57	$17.51
2004	1,062	1.4%	3,966	5.1%	5,028	6.5%	$17.21	$17.88	$17.74
2005	1,516	1.2%	4,968	3.9%	6,484	5.1%	$0.15	$7.94	$6.12

27 Beginning June 1, 1999, when the PJM Capacity Credit Market began to use unforced capacity.

28 Prior state of the market reports showed weighted-average 1999 prices of $3.63 (daily), $70.66 (monthly and multimonthly) and $52.86 (combined). Corrected values are shown here.

Market Structure for the ComEd Capacity Market

The ComEd Control Area[29] was integrated into PJM on May 1, 2004, but the ComEd Capacity Market was not implemented until June 1, 2004. During May 2004, capacity obligations in the ComEd Control Area were satisfied wholly by Commonwealth Edison Company according to the procedures PJM established. The ComEd Capacity Market operated under rules based on installed capacity with obligation fixed on a monthly basis. There was no daily capacity credit market. The interim ComEd Capacity Market structure included three intervals: June to September 2004; October to December 2004; and January to May 2005. The capacity obligation for each interval was based on the forecasted interval peak and the installed reserve margin, both of which were recalculated for each interval.[30] These rules remained in effect through May 31, 2005, when the ComEd Control Zone became part of the PJM Capacity Market.[31]

Ownership Concentration

For the period June 1, 2004, through May 31, 2005, the MMU analyzed market concentration ratios and pivotal supplier measures for the ComEd Market.

June 2004 through May 2005

Structural analysis[32] indicates that from June 2004 through May 2005, ComEd's Monthly and Multimonthly Capacity Credit Markets exhibited high levels of concentration.[33] HHIs for Monthly and Multimonthly Capacity Credit Markets averaged 5907, with a maximum of 10000 and a minimum of 2253, while all 60 of the auctions had an HHI greater than 1800. (See Table 5-14.) The highest market share for any entity in any auction was 100.0 percent. One entity owned or controlled almost 60 percent of total capacity in the ComEd Control Zone.

Table 5-14 - ComEd Capacity Market HHI: June 2004 through May 2005

Statistic	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	NA	5907
Minimum	NA	2253
Maximum	NA	10000
Highest Market Share	NA	100.0%
# Auctions	NA	60
# Auctions with HHI >1800	NA	60
% Auctions with HHI >1800	NA	100.0%

29 ComEd was known as the ComEd Control Area from May 1, 2004, until October 1, 2004, when it became the ComEd Control Zone. These terms are used interchangeably throughout this section.

30 "Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone during the Interim Period," "PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region" (December 20, 2004), pp. 48A – 48D.

31 See Appendix E, "Capacity Markets."

32 See Section 2, "Energy Market, Part 1," for a discussion of concentration ratios and the HHI.

33 ComEd Capacity Market results are reported by the time period during which the auction was run and not by the time period to which the auction applies.

Table 5-15 - ComEd Capacity Market residual supply index (RSI): June 2004 through May 2005

Statistic	Daily Market RSI	Monthly and Multimonthly Market RSI
Average	NA	2.76
Minimum	NA	0.00
Maximum	NA	25.60
# Auctions	NA	60
# Auctions with RSI < 1.0	NA	26
% Auctions with RSI < 1.0	NA	43.3%
# Auctions with <= 3 Pivotal Suppliers	NA	58
% Auctions with <= 3 Pivotal Suppliers	NA	96.7%

Table 5-15 shows RSI values for the Monthly and Multimonthly Capacity Credit Market Auctions for the ComEd Capacity Market. The high average RSI value of 2.76 and the high maximum RSI value resulted from the relatively small volumes bid in Capacity Credit Market Auctions. Of 60 capacity auctions held for ComEd, 26 (43.3 percent) had RSI values of less than 1.0, meaning that a single supplier was pivotal in these auctions, while 58 of the auctions (96.7 percent) had three or fewer jointly pivotal suppliers.

Total Capacity

The market structure for total capacity in the aggregate ComEd Capacity Market is shown for specific dates in Table 5-16. The analysis uses capacity ownership as of the beginning of each interval (June 1, 2004, October 1, 2004, and January 1, 2005) and on May 31, 2005 (the last day of a separate ComEd Capacity Market). The analysis of total capacity is included as it represents conditions in the Capacity Market without regard to whether capacity was sold in bilateral or PJM-operated markets. This evaluation is relevant because only about 6 percent of ComEd Control Zone capacity was traded in PJM-operated markets.

The analysis shows that on these dates, capacity resources exceeded capacity obligations in the ComEd Capacity Market. The decrease in obligation of 8,497 MW on October 1 was the result of the lower interval peak for the October to December period. The obligation increased by 520 MW on January 1 to reflect the higher interval peak of the January to May period. Installed capacity decreased by 4,916 MW over this period with retirement of capacity resources accounting for 3,466 MW and increased exports offset by a small increase in imports accounting for the remainder. (See Table 5-16.) The retirement of capacity resources by the two largest capacity owners in the ComEd Capacity Market led to a decrease in market concentration reflected in the reduction of the HHI from 4525 to 4070 and a decrease in the maximum market share from 64.2 percent to 59.8 percent. One pivotal supplier existed throughout the period.

Table 5-16 - ComEd Capacity Market: June 2004 through May 2005

	01-Jun	01-Oct	01-Jan	31-May
Obligation (MW)	25,162	16,665	17,185	17,185
Installed Capacity (MW)	28,999	27,740	24,676	24,083
HHI	4525	4404	3978	4070
Highest Market Share	64.2%	63.3%	58.9%	59.8%
RSI	0.41	0.59	0.59	0.56
Pivotal Suppliers	1	1	1	1

Supply and Demand

June 2004 through May 2005

From June 2004 through May 2005, ComEd EDCs together had an 81.6 percent market share of load obligation in the ComEd Capacity Market. (See Table 5-17.) All customers in the ComEd Control Zone were eligible for retail access although eligible residential customers did not switch to retail access service in 2005.[34] Instead, switching activity was limited to commercial, industrial and governmental customers.[35] Switching was affected by a number of factors. The local utility's bundled rates have been fixed at, or below, 1997 levels since passage of the Illinois Electric Service Customer Choice and Rate Relief Law of 1997.[36] Bundled rates will remain frozen by legislative mandate until the end of 2006.[37] In addition, any customer switching from bundled service to a retail choice option must pay a transition charge on energy bought from alternative suppliers. Transition charges will end in the ComEd service territory on December 31, 2006.[38]

During the period under discussion, load-serving entities could meet their ComEd Control Zone load obligations through self-supply,[39] the ComEd Capacity Credit Market or bilateral contracts with third parties. Reliance on these options varied by market sector. (See Table 5-18, Table 5-19 and Table 5-20.)[40] From June 2004 through May 2005, ComEd EDCs self-supplied an average of only 0.1 percent of their load obligations, with their remaining obligations supplied almost entirely through bilateral contracts with third parties (112.4 percent). Commonwealth Edison Company (an EDC in the ComEd Control Zone) was the major electric distribution company in this market. Having spun off its generating assets to an affiliate, ExGen (included among ComEd Control Zone EDC affiliates), the company met its entire capacity obligation through bilateral transactions with this affiliate. Until October 1, 2004, ComEd EDCs, on average, met their load obligation almost exactly. When EDC load obligations decreased on October 1, EDC purchases of capacity credits through bilateral contracts decreased as well, but by less than the reduction in their load obligations, resulting in a net excess position. All generating affiliate sectors, which had no load obligations, were net capacity credit sellers and remained in net excess positions. All marketing affiliate sectors, which were net capacity credit buyers, purchased more capacity credits than their obligations, but had lower net excess positions, in MW, than the generating affiliate sectors.

34 See Illinois Commerce Commission, "Competition in Illinois Retail Electric Markets in 2004" (April 2005) < http://www.icc.illinois.gov/ec/docs/050401garpt16120b.pdf > (127 KB). In a phone interview on January 6, 2006, ICC staff confirmed that switching remains limited to nonresidential customers.

35 See Illinois Commerce Commission, Electric Switching Statistics (December 2005) < http://www.icc.illinois.gov/ec/docs/dasrcomed.xls > (181 KB).

36 Illinois General Assembly, "Electric Service Customer Choice and Rate Relief Law of 1997," (220 ILCS 5/16-111 (b)).

37 See Illinois Commerce Commission, "Final Report of the Illinois Commerce Commission's Post-2006 Initiative" (December 2004) < http://www.icc.illinois.gov/ec/docs/041208ecPostRptExe.pdf > (85 KB).

38 See Illinois Commerce Commission, "Plug In Illinois"< http://www.icc.illinois.gov/pluginillinois/Timeline.asp >.

39 Self-supply is defined as the unforced MW of the units owned by an entity.

40 Negative values in the "Capacity Credit Market" and in the "Net Bilateral Contracts" columns mean that a sector sold more capacity credits than it purchased for the relevant time period. A positive number means that a sector purchased more capacity credits than it sold for the relevant time period.

Table 5-17 - ComEd Capacity Market load obligation served: June 2004 through May 2005

	Average Obligation (MW)							
	ComEd EDCs	ComEd EDC Generating Affiliates	ComEd EDC Marketing Affiliates	Non ComEd EDC Generating Affiliates	Non ComEd EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Jun-04	20,503	0	3,040	0	1,520	0	99	25,162
Jul-04	20,601	0	2,937	0	1,530	0	94	25,162
Aug-04	20,847	0	2,716	0	1,510	0	88	25,161
Sep-04	20,555	0	3,001	0	1,519	0	88	25,163
Oct-04	13,589	0	2,006	0	1,012	0	58	16,665
Nov-04	13,573	0	2,031	0	1,016	0	46	16,666
Dec-04	13,582	0	2,024	0	1,014	0	45	16,665
Jan-05	13,924	0	2,143	0	1,069	0	49	17,185
Feb-05	13,945	0	2,135	0	1,056	0	49	17,185
Mar-05	13,938	0	2,141	0	1,058	0	49	17,186
Apr-05	13,890	0	2,160	0	1,085	0	49	17,184
May-05	13,880	0	2,153	0	1,087	0	65	17,185
Average	16,075	0	2,374	0	1,207	0	65	19,721
% of Total Obligation	81.6%	0.0%	12.0%	0.0%	6.1%	0.0%	0.3%	100.0%

Table 5-18 - ComEd Capacity Market load obligation served by ComEd EDCs and affiliates: June 2004 through May 2005

	ComEd EDCs					ComEd EDC Generating Affiliates					ComEd EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun-04	0	10	20,493	20,503	0	13,888	212	(13,369)	0	731	0	715	2,326	3,040	1
Jul-04	0	10	20,591	20,601	0	13,888	212	(13,657)	0	443	0	714	2,227	2,937	4
Aug-04	0	10	20,837	20,847	0	13,888	212	(13,650)	0	450	0	635	2,209	2,716	128
Sep-04	0	10	20,546	20,555	1	13,888	212	(13,517)	0	583	0	675	2,328	3,001	2
Oct-04	21	(9)	16,531	13,589	2,954	13,888	(88)	(11,478)	0	2,322	0	642	1,835	2,006	471
Nov-04	21	(9)	16,512	13,573	2,951	13,888	(88)	(11,458)	0	2,342	0	645	1,860	2,031	474
Dec-04	21	(9)	16,522	13,582	2,952	13,888	(88)	(11,522)	0	2,278	0	645	1,859	2,024	480
Jan-05	21	(11)	16,941	13,924	3,027	13,888	(350)	(13,318)	0	220	0	752	1,859	2,143	468
Feb-05	21	(11)	16,967	13,945	3,032	13,932	(325)	(13,323)	0	284	0	801	1,798	2,135	464
Mar-05	21	(11)	16,959	13,938	3,031	13,932	(275)	(13,249)	0	408	0	852	1,755	2,141	466
Apr-05	21	(11)	16,901	13,890	3,021	13,907	(330)	(13,299)	0	278	0	856	2,054	2,160	750
May-05	21	(10)	16,888	13,880	3,019	13,882	(340)	(13,242)	0	300	0	849	2,053	2,153	749
Average	14	(3)	18,060	16,075	1,996	13,896	(85)	(12,920)	0	891	0	731	2,014	2,374	371
% of Total Obligation	0.1%	0.0%	112.4%	112.5%	12.5%	NA	NA	NA	NA	NA	0.0%	30.8%	84.8%	115.6%	15.6%

Table 5-19 - ComEd Capacity Market load obligation served by non-ComEd EDC affiliates: June 2004 through May 2005

	Non-ComEd EDC Generating Affiliates					Non-ComEd EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun-04	12,079	(1,120)	(8,353)	0	2,606	0	410	1,262	1,520	152
Jul-04	10,456	(1,005)	(8,579)	0	872	0	405	1,126	1,530	1
Aug-04	10,456	(1,015)	(8,474)	0	967	0	494	1,447	1,510	431
Sep-04	10,456	(1,034)	(8,585)	0	837	0	424	1,467	1,519	372
Oct-04	10,456	(520)	(6,907)	0	3,029	0	220	1,767	1,012	975
Nov-04	10,580	(510)	(7,207)	0	2,863	0	190	1,773	1,016	947
Dec-04	10,755	(510)	(7,207)	0	3,038	0	195	1,776	1,014	957
Jan-05	8,765	(470)	(5,623)	0	2,672	0	279	1,455	1,069	665
Feb-05	8,765	(470)	(6,123)	0	2,172	0	231	1,604	1,056	779
Mar-05	8,596	(470)	(5,973)	0	2,153	0	197	1,454	1,058	593
Apr-05	8,596	(520)	(5,973)	0	2,103	0	225	1,173	1,085	313
May-05	8,596	(520)	(5,994)	0	2,082	0	220	1,170	1,087	303
Average	9,883	(681)	(7,086)	0	2,116	0	291	1,455	1,207	539
% of Total Obligation	NA	NA	NA	NA	NA	0.0%	24.1%	120.6%	144.7%	44.7%

Table 5-20 - ComEd Capacity Market load obligation served by non-EDC affiliates: June 2004 through May 2005

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	Capacity Credit Market (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jun-04	3,375	(227)	(2,800)	0	348	0	0	99	99	0
Jul-04	3,375	(337)	(2,750)	0	288	0	0	94	94	0
Aug-04	3,375	(337)	(3,030)	0	8	0	0	88	88	0
Sep-04	3,375	(287)	(3,030)	0	58	0	0	88	88	0
Oct-04	3,375	(245)	(2,725)	0	405	0	0	71	58	13
Nov-04	3,375	(228)	(2,660)	0	487	0	0	55	46	9
Dec-04	3,375	(233)	(2,720)	0	422	0	0	55	45	10
Jan-05	3,375	(200)	(2,745)	0	430	0	0	59	49	10
Feb-05	3,375	(227)	(2,745)	0	403	0	0	59	49	10
Mar-05	3,375	(293)	(2,695)	0	387	0	0	59	49	10
Apr-05	3,375	(220)	(2,745)	0	410	0	0	59	49	10
May-05	3,375	(200)	(2,745)	0	430	0	0	79	65	14
Average	3,375	(253)	(2,783)	0	339	0	0	72	65	7
% of Total Obligation	NA	NA	NA	NA	NA	0.0%	0.0%	111.4%	111.4%	11.4%

The level of resources available to satisfy the capacity obligation in the ComEd Capacity Market during any month reflected the addition of new resources, the retirement of old resources and the importing or exporting of capacity resources.

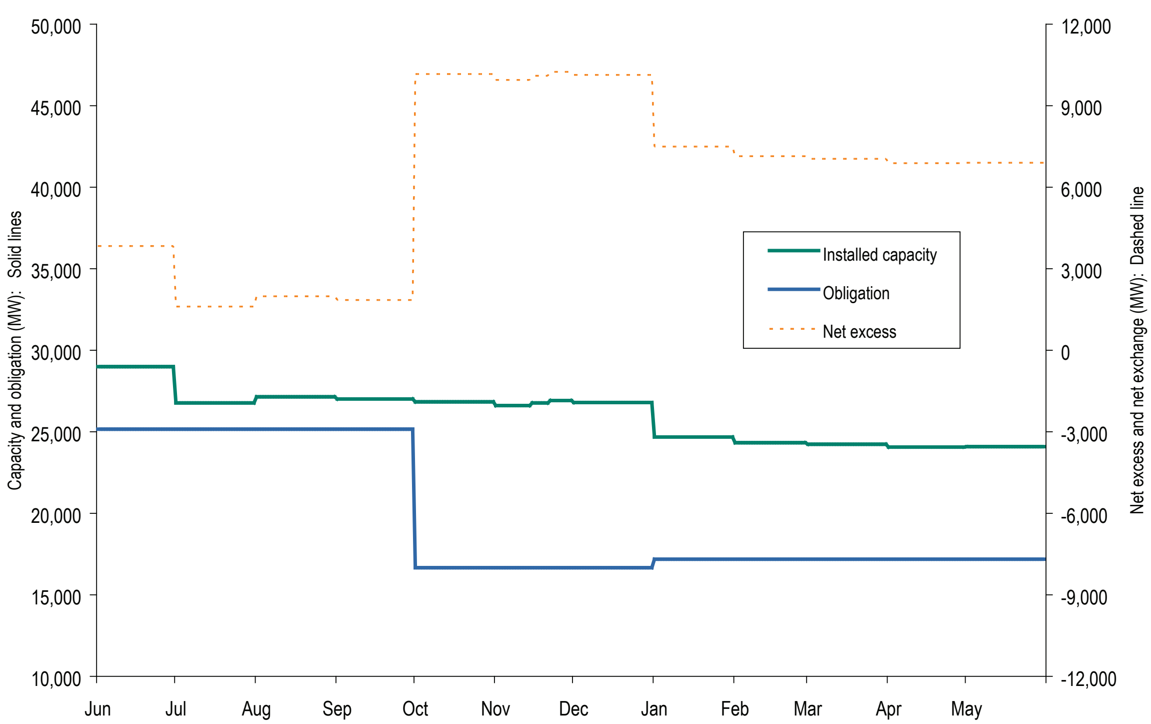
Net excess equals total capacity resources less capacity obligation. Since obligation includes expected load plus a reserve margin, a net excess of zero or greater is consistent with established reliability objectives. As shown in Table 5-21 and Figure 5-7, for June 2004 through May 2005, the ComEd Capacity Credit Market had an average net excess of 6,261 MW, or 31.7 percent of average obligation for the period.[41]

41 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.

Table 5-21 - ComEd capacity summary (MW): June 2004 through May 2005

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	25,980	1,549	24,068	28,999
Unforced Capacity	25,980	1,549	24,068	28,999
Obligation	19,721	3,867	16,665	25,163
Sum of Excess	6,261	3,094	1,609	10,249
Sum of Deficiency	0	0	0	0
Net Excess	6,261	3,094	1,609	10,249
Imports	481	117	360	651
Exports	1,669	581	747	2,464
Net Exchange	(1,188)	487	(1,831)	(343)
Internal Unit-Specific Transactions	5,150	1,441	3,400	6,775
Internal Capacity Credit Transactions	25,836	2,085	23,659	29,025
Total Internal Bilateral Transactions	30,986	3,275	28,061	35,801
Daily Capacity Credits	0	0	0	0
Monthly Capacity Credits	126	66	10	221
Multimonthly Capacity Credits	1,103	226	895	1,457
All Capacity Credits	1,229	251	949	1,629
MIL Credits	224	86	153	346

Figure 5-7 - Capacity obligation for the ComEd Capacity Market: June 2004 through May 2005



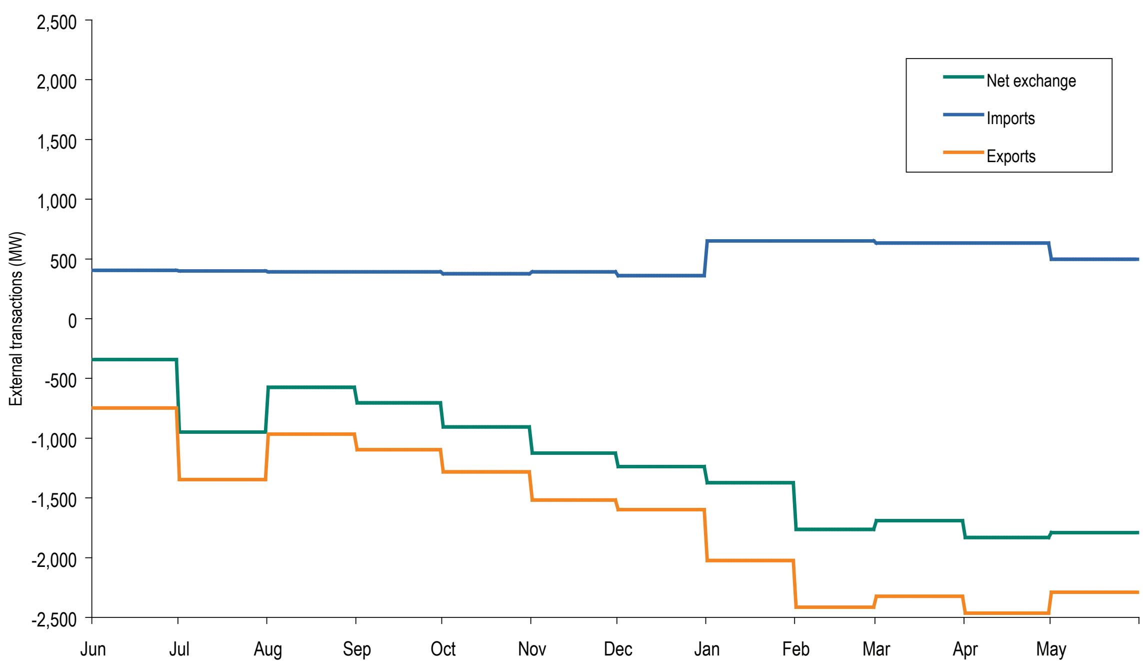
External and Internal Capacity Transactions

ComEd capacity resources were traded bilaterally within and outside of ComEd.

External Bilateral Transactions

External bilateral transactions included imports of capacity resources from other control areas and exports of capacity resources to control areas outside of ComEd. Figure 5-8 presents ComEd's external bilateral capacity transaction data for June 2004 through May 2005. (Table 5-21 also includes summary data on imports and exports.) During this period, the ComEd Control Zone was a net exporter of capacity resources as exports grew from 747 MW on June 1 to 2,289 MW on May 31. Almost half of this increase was attributable to increased exports to the PJM Capacity Market, which rose from 150 MW on June 1 to 875 MW on May 31. With imports remaining relatively constant during this period, this increase in exports led to a decrease in net exchange of 1,448 MW. Net exchange is equal to imports less exports.

Figure 5-8 - External ComEd Capacity Market transactions: June 2004 through May 2005

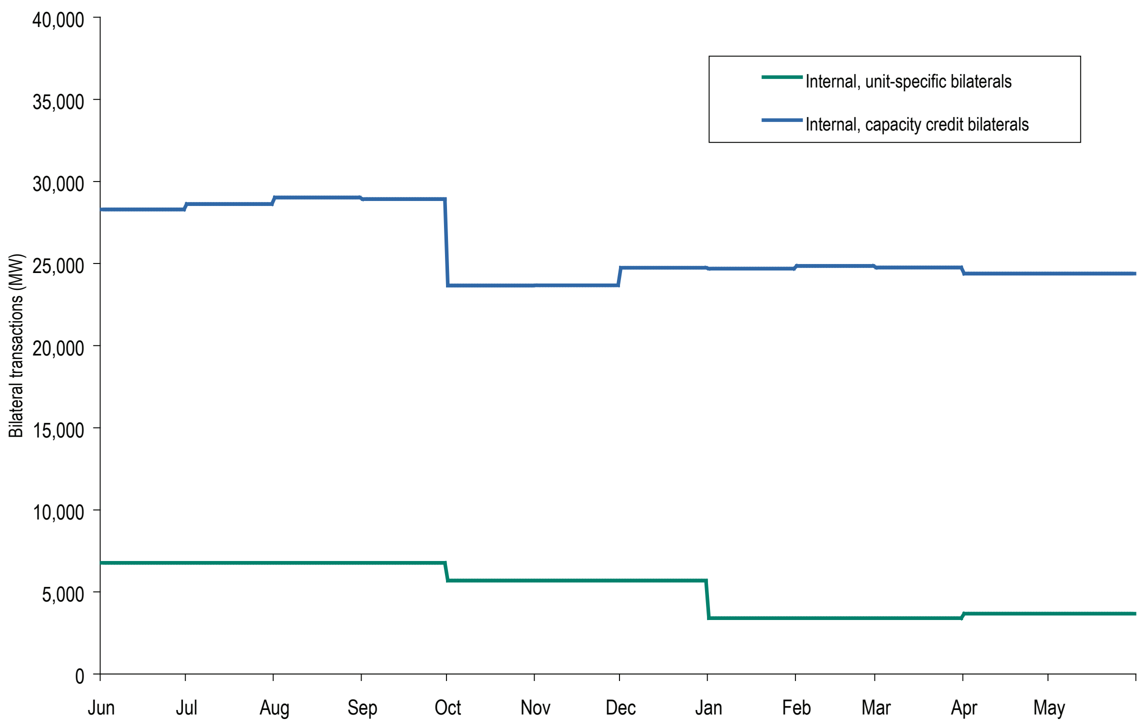


Internal Bilateral Transactions

Internal bilateral transactions are agreements between two parties for the buying and selling of capacity credits within PJM. Unit-specific transactions are for capacity credits from a specific generating unit while capacity credit transactions are for non-unit-specific capacity credits. Both types of transactions may be traded multiple times between parties with the result that transaction volume can exceed obligation.

Figure 5-9 presents data on ComEd's internal bilateral capacity transactions for June 2004 through May 2005. (Table 5-21 also includes summary data on internal bilateral transactions.) The decreases of 1,092 MW in unit-specific bilaterals and of 5,269 MW in capacity credit bilaterals on October 1 were the result of the lower interval peak for the October to December period.

Figure 5-9 - Internal bilateral ComEd Capacity Market transactions: June 2004 through May 2005



Market Performance for the ComEd Capacity Market

Capacity Credit Market Volumes and Prices

Between June 2004 and May 2005, PJM operated 60 Monthly and Multimonthly Capacity Credit Market Auctions to help LSEs satisfy their ComEd Control Zone capacity obligations for the June 2004 to May 2005 capacity planning period.[42] Table 5-21 shows that Monthly and Multimonthly Capacity Credits averaged 1,229 MW, or 6.2 percent of the average capacity obligation for this period.

Table 5-22 shows ComEd Monthly and Multimonthly Capacity Credit Market average daily volumes, which decreased on October 1 as a result of the lower peak for the October through December interval and then increased on January 1 to reflect the higher obligation for the January to May interval. Table 5-22 also shows the ComEd Monthly and Multimonthly Capacity Credit Market prices for June 2004 through May 2005. The volume-weighted, average price was $23.99 with a range from a low of $16.14 per MW-day in May to a high of $32.26 per MW-day in July.

42 See PJM, "NICA Installed Capacity Credit Results" < ftp://ftp.pjm.com/pub/ capacity_credit_market/results/nica/ccmmonthly-nica.csv > (4.8 KB).

While there is no information to support the statement that individual suppliers offered their capacity at a competitive price based on unit costs, and although the market structure in the ComEd Capacity Market was highly concentrated as evidenced by the high HHIs, market performance results were, with the exception of July 2004, less than the $30 per MW-day offer cap that had been proposed by PJM to mitigate market power in the ComEd Capacity Market. The MMU concludes that the ComEd Capacity Market results were reasonably competitive for June 2004 through May 2005.

Table 5-22 - ComEd Capacity Credit Markets: June 2004 through May 2005

	Monthly and Multimonthly Daily Average Volume (MW)	Monthly and Multimonthly Weighted-Average Price ($ per MW-day)
Jun-04	1,507	$29.06
Jul-04	1,525	$32.26
Aug-04	1,584	$28.77
Sep-04	1,629	$28.64
Oct-04	949	$24.43
Nov-04	952	$24.29
Dec-04	957	$24.17
Jan-05	1,031	$19.24
Feb-05	1,086	$18.21
Mar-05	1,138	$17.39
Apr-05	1,167	$16.83
May-05	1,218	$16.14
Average	1,229	$23.99

Generator Performance

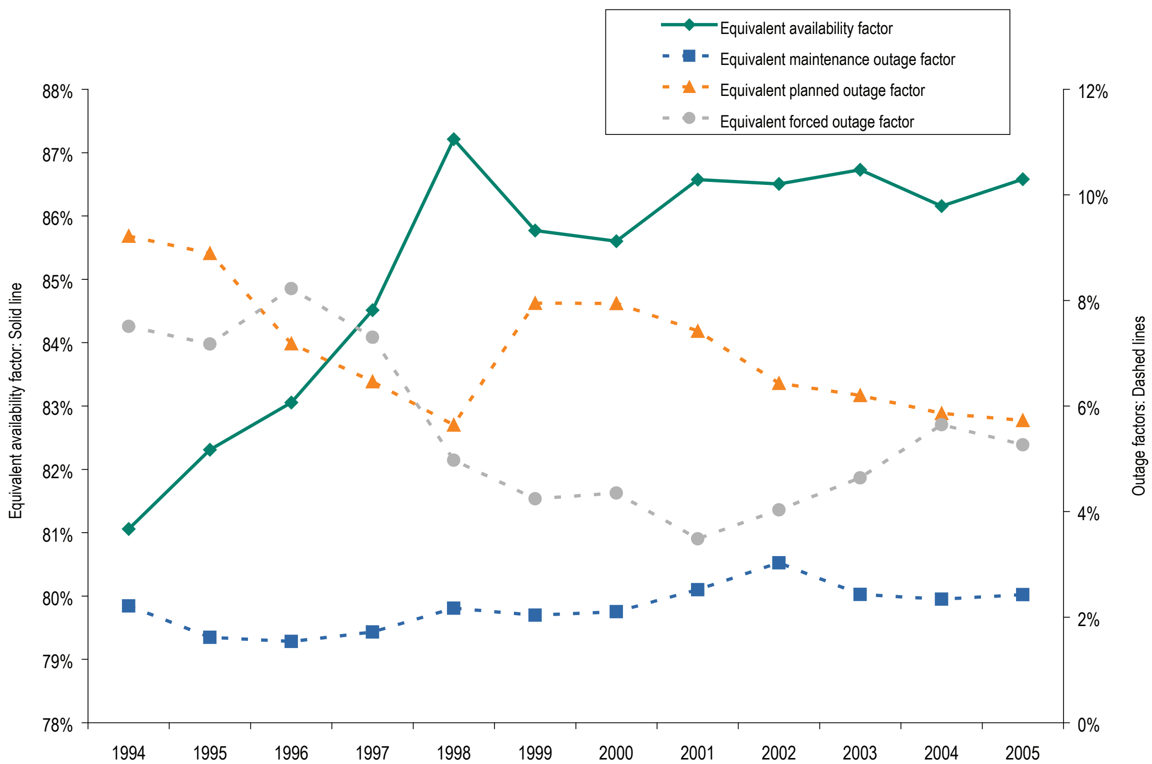
Generator performance can be defined using indices calculated from historical data. Generator performance indices include measures based on total hours in a period (generator performance factors) and measures based on hours when units are needed to operate by the system operator (generator forced outage rates).

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable. Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year that a unit is available to generate at full capacity while the three outage factors include all the hours that a unit is unavailable. The EMOF is the proportion of hours in a year that a unit is unavailable due to maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year that a unit is unavailable due to planned outages and planned deratings. The EFOF is the proportion of hours in a year that a unit is unavailable due to forced outages and forced deratings.

The PJM aggregate[43] EAF increased from 86.2 percent in 2004 to 86.6 percent in 2005.[44] The EFOF decreased by 0.4 percentage points from 2004 to 2005, the EPOF decreased by about 0.1 percentage points and the EMOF increased by about 0.1 percentage points. (See Figure 5-10.) The EAF for all PJM control zones was 87.6 percent in 2005.

Figure 5-10 - PJM equivalent outage and availability factors: Calendar years 1994 to 2005



Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. Unforced capacity for any individual generating unit is equal to one minus the EFORd multiplied by the unit's net dependable summer capability. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

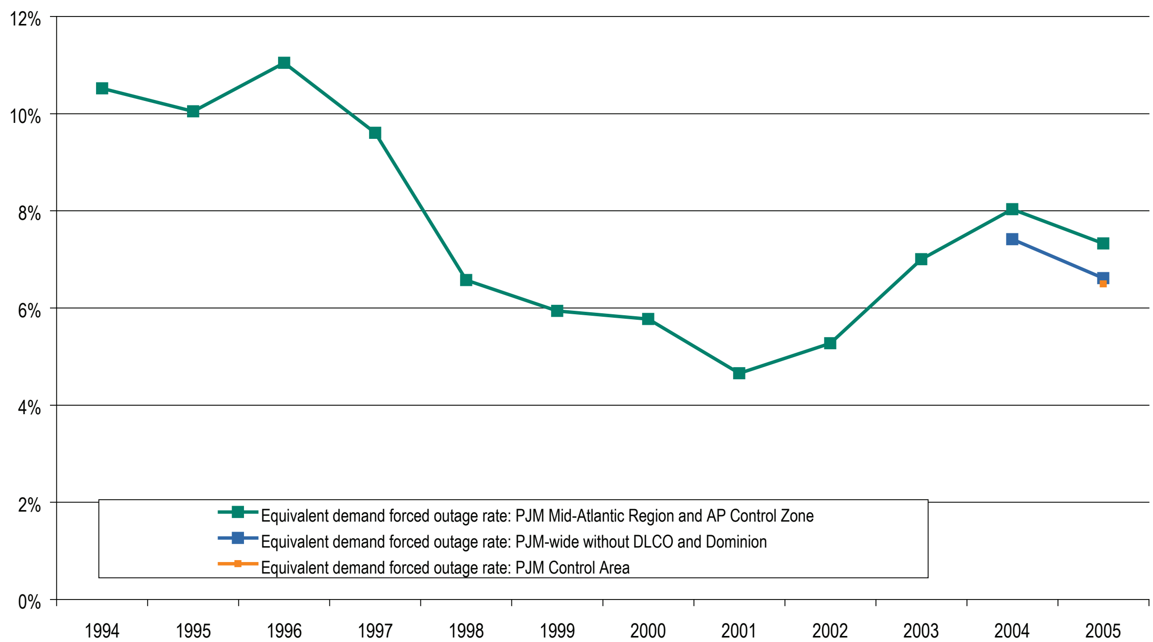
43 The performance factor data include only units from the PJM Mid-Atlantic Region and the AP Control Zone for comparability with prior years' state of the market reports. In order to maintain comparability, units from other control zones that were considered capacity resource imports in prior state of the market reports are also included. Data from the more recently integrated control zones will be included when there are two complete calendar years of data for each control zone.

44 Data are for 12 months ended December 31, 2005, as downloaded from the PJM GADS database on January 24, 2006. Data for the year 2005 may be incomplete as of the download date as corrections can be made at anytime with permission from the PJM GADS administrators.

EFORd calculations use historical data, including equivalent forced outage hours,[45] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[46] Between 1996 and 2001, the average PJM EFORd declined, reaching 4.6 percent in 2001, then increased to 5.2 percent in 2002, 7.0 percent in 2003 and 8.0 percent in 2004 before it again decreased in 2005 to 7.3 percent.[47]

Figure 5-11 shows the average EFORd since 1994 for all units in the PJM Mid-Atlantic Region and AP Control Zone. Figure 5-11 shows separately the average EFORd for 2004 and 2005 for all units in the PJM Mid-Atlantic Region, AP Control Zone, AEP Control Zone and DAY Control Zone. Figure 5-11 also shows separately for 2005 the average EFORd for the entire PJM Control Area including the DLCO and Dominion Control Zones. The 2005 EFORd was 6.5 percent for the entire PJM Control Area.[48]

Figure 5-11 - Trends in PJM equivalent demand forced outage rate (EFORd): Calendar years 1994 to 2005



45 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

46 See PJM Manual M22, "Generator Resource Performance Indices, Revision 14" (June 1, 2005), Equation 8.

47 Data are for the 12 months ended December 31, 2005, as downloaded from the PJM GADS database on January 24, 2006. Data for the year 2005 may be incomplete as of the download date as corrections can be made at anytime with permission from the PJM GADS administrators.

48 The EFORd is reported for the entire PJM Control Area only for 2005 because data are either not available or are incomplete for the years 1994 through 2003 for the AEP, DAY and ComEd Control Zones and for 1994 through 2004 for the DLCO and Dominion Control Zones. PJM Control Area data for 2004 include seven months of data for the ComEd Control Zone and three months of data for the AEP and DAY Control Zones, consistent with their May 1, 2004, and October 1, 2004, integration dates. PJM Control Area data for 2005 include seven months of data for the Dominion Control Zone and 12 months of data for the DLCO Control Zone consistent with the corresponding May 1, 2005, and January 1, 2005, integration dates. The capacity of generators in these control zones has been prorated based on the number of months of data included.

Components of Change in EFORd

Table 5-23 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[49] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-23 - Contribution to EFORd for specific unit types (In percentage points): Calendar years 1998 through 2005

Unit Type	1999	2000	2001	2002	2003	2004	2005	Change in 2005 from 2001	Change in 2005 from 2004
Combined Cycle	0.1	0.1	0.1	0.4	0.7	1.1	0.9	0.8	(0.2)
Combustion Turbine	1.5	1.0	0.7	0.7	1.4	1.4	2.1	1.4	0.7
Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.0
Nuclear	0.5	0.6	0.3	0.3	0.4	0.6	0.2	(0.1)	(0.4)
Steam	3.9	3.8	3.5	3.8	4.4	4.8	4.0	0.5	(0.8)
Total	6.0	5.6	4.6	5.2	7.0	8.0	7.3	2.7	(0.7)

The increase in the EFORd of 2.7 percentage points (a 58.7 percent increase) between 2001 and 2005 resulted primarily from combustion turbine units and combined-cycle units which together contributed 2.2 of the 2.7 percentage point increase, or 81 percent of the increase.

The decrease in EFORd of 0.7 percentage points (an 8.8 percent decrease) from 2004 to 2005 resulted primarily from fossil steam and nuclear units offset in part by combustion turbines.[50] Fossil steam units (162 generating units) contributed -0.8 percentage points, nuclear units (13 generating units) contributed -0.4 percentage points, combined-cycle units (60 generating units) contributed -0.2 percentage points. Combustion turbine units (300 generating units) added 0.7 percentage points to partially offset the decreases for other unit types.

Of the 658 generating units in the EFORd analysis, during calendar year 2005, 284 units had decreased EFORds, 254 units had increased EFORds and the remaining 120 units had unchanged EFORds. The 284 units with lower forced outage rates reduced the EFORd by 3.5 percentage points from 10.8 percent to the observed 7.3 percent EFORd.

The increase in EFORd since 2001 for the PJM Mid-Atlantic Region and AP Control Zones together has been, in part, the result of a change in the mix of capacity resulting from the addition of combined-cycle and combustion turbine capacity. In 2001, this area had approximately 67,400 MW of installed capacity. Between 2001 and 2005, there was a net decrease in steam capability of approximately 400 MW, from 36,800 MW to 36,400 MW; no change in nuclear capability; and a net increase in combined-cycle and combustion turbine capability of 11,500 MW, from 14,000 MW in 2001 to 25,500 MW in 2005. In 2001 steam and nuclear capacity accounted for 74 percent of capacity; combined-cycle units and combustion turbines accounted for 21 percent. In 2005, steam and nuclear capacity accounted for 63 percent of capacity; combined-cycle units and combustion turbines accounted for 32 percent.

49 The generating unit types are: steam, nuclear, diesel, combustion turbine, combined cycle, run of river hydroelectric and pumped storage hydroelectric. For some tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

50 A single unit may include more than one set of generator terminals aggregated as a single generator.

Of the 2.7 percentage point change in system EFORd from 2001 to 2005 (See Table 5-23), 2.2 percentage points, or 81 percent, were contributed by combined-cycle and combustion turbine units. Changes in outage rates by unit type and changes in capacity by unit type combine to produce the observed impacts on the system EFORd. Both increased combustion turbine and combined-cycle capacity and increased forced outage rates for these unit types have contributed to the increased system EFORd. Table 5-24 shows the relative contributions of increased EFORd and increased capacity to EFORd levels by unit type and for the system. Twenty-six percent of the contribution of combined-cycle units to the increased system EFORd was the result of additional combined-cycle capacity while more than 94 percent of the contribution of combustion turbine units to the increased system EFORd was the result of higher EFORd levels for combustion turbines. Overall, 92 percent of the increase in EFORd from 2001 to 2005 was the result of increased EFORd rather than by a change in the mix of units.

Table 5-24 - Percent change in contribution to EFORd (By unit type): 2001 compared to 2005

Unit Type	Percent Change in Contribution 2005 from 2001 Due to Change in Capacity	Percent Change in Contribution 2005 from 2001 Due to Change in EFORd
Combined Cycle	25.9 %	74.1 %
Combustion Turbine	5.7 %	94.3 %
Diesel	3.7 %	96.3 %
Hydroelectric	(2.7 %)	102.7 %
Nuclear	0.0 %	100.0 %
Steam	(3.6 %)	103.6 %
All Unit Types	8.1 %	91.9 %

Compared with the PJM Mid-Atlantic Region and AP Control Zones' average EFORd, combined-cycle average EFORd for 2001 was extremely low. For the combined-cycle units, EFORd increased to slightly greater than 5.3 percent in 2005 from slightly greater than 1.7 percent in 2001. Combined-cycle unit EFORd increased by 282 percent between 2001 and 2004 but decreased slightly in 2005. (See Table 5-25.)

Table 5-25 - Five-year PJM EFORd data comparison to NERC five-year average for different unit types

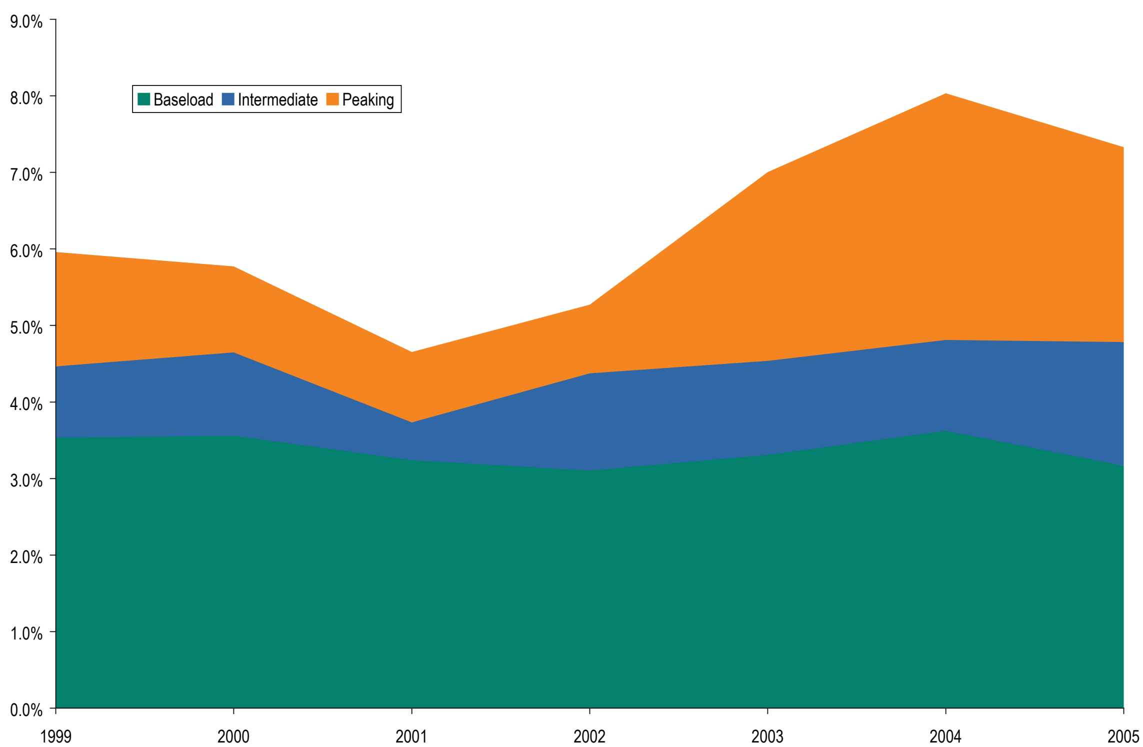
Unit Type	2001	2002	2003	2004	2005	NERC 2000-2004
Combined Cycle	1.7 %	5.3 %	5.7 %	6.5 %	5.3 %	NA
Combustion Turbine	4.6 %	4.4 %	8.9 %	9.3 %	14.0 %	8.9/10.1 %
Diesel	10.6 %	7.1 %	5.7 %	10.4 %	14.0 %	14.1 %
Run of River Hydro	1.2 %	1.0 %	0.9 %	2.5 %	1.9 %	3.6 %
Nuclear	1.5 %	1.7 %	2.1 %	3.4 %	1.4 %	4.3 %
Pumped Storage	0.8 %	1.1 %	1.3 %	2.1 %	1.2 %	4.6 %
Steam	6.4 %	7.1 %	9.0 %	10.3 %	8.6 %	6.2 %
Overall	4.6 %	5.2 %	7.0 %	8.0 %	7.3 %	NA

Table 5-25 compares PJM EFORd data by unit type to North American Electric Reliability Council (NERC) data for corresponding unit types.[51] NERC did not publish average EFORd for combined-cycle units because the new calculations for combined-cycle blocks were not ready and had not been tested.[52] While the PJM combustion turbine forced outage rates have been near or below the NERC five-year average, the PJM EFORd for combustion turbines exceeded the NERC average in 2005.[53] PJM 2005 forced outage rates for hydroelectric and nuclear units were below the NERC averages while PJM forced outage rates for steam exceeded the NERC averages.

Duty Cycle and EFORd

In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[54] Figure 5-12 shows the increased contribution of intermediate and peaking units to system average EFORd beginning in 2001. Of 11,500 MW of combined-cycle and combustion turbine units added since 2001, approximately 10,800 MW are in the intermediate (9,400 MW) and peaking (1,400 MW) classes.

Figure 5-12 - Contribution to EFORd by duty cycle



51 The PJM data include all combustion turbines as a single unit type.

52 Combined-cycle blocks consist of one or more combustion turbines and one or more heat recovery steam generators. The configuration may vary for each individual combined-cycle unit.

53 NERC defines combustion turbines in two categories: jet engines and gas turbines. Their EFORd for the 2000 to 2004 period are 8.9 percent and 10.1 percent, respectively, per the NERC GADS "2000-2004 Generating Unit Statistical Brochure - Units Reporting Events." < ftp://www.nerc.com/pub/sys/all_updl/gads/gar/2000-2004-Generating-Unit-Statistical-Brochure-Units-Reporting-Events.zip > (28 KB).

54 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined to be a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined to be a unit that generates from 10 percent to 50 percent of its available hours. A peaking unit is defined to be a unit that generates less than 10 percent of its available hours. These terms were defined for the purposes of this analysis.

SECTION 6 – ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation services; 3) regulation and frequency response services; 4) energy imbalance service; 5) operating reserve – spinning reserve services; and 6) operating reserve – supplemental reserve services.[1] Of these, PJM currently provides regulation, energy imbalance and spinning reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis.

Regulation matches generation with very short-term changes in load by moving the output of selected generators up and down via an automatic control signal.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes). Longer term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Spinning reserve is a form of primary reserve. To provide spinning a generator must be synchronized to the system and capable of providing output within 10 minutes.

Both the Regulation and Spinning Reserve Markets are cleared on a real-time basis. A unit can be selected for either spinning reserve or regulation or neither, but it cannot be selected for both. The Regulation and Spinning Reserve Markets are cleared simultaneously and cooptimized with the Energy Market and operating reserve requirements to minimize the cost of the combined products.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling.[3] Generation owners are paid according to the FERC-approved reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

During the last two calendar years, PJM has integrated five control zones. In the *2004 State of the Market Report* the calendar year was divided into three phases, corresponding to market integration dates. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[4]

- **Phase 1 (2004).** The four-month period from January 1 through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[5] and the Allegheny Power Company (AP) Control Zone.[6]

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE.

3 See "PJM Manual for Scheduling Operations, M-11," Revision 25 (August 19, 2005), p. 71.

4 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

5 The Mid-Atlantic Region is comprised of the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO).

6 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of the control zone and control area concepts during PJM's Phase 3 integrations. For simplicity, zones are referred to as control zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

- **Phase 2 (2004).** The five-month period from May 1 through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the Commonwealth Edison Company Control Area (ComEd).[7]

- **Phase 3 (2004).** The three-month period from October 1 through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- **Phase 4 (2005).** The four-month period from January 1 through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP, ComEd, AEP and DAY Control Zones plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1 through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

In both Phase 4 and Phase 5, PJM operated two Regulation Markets: one for the Mid-Atlantic Region and a second for the Western Region. On August 1 of Phase 5, PJM combined both into a single PJM Combined Regulation Market for a six-month trial period. After the trial period, based on analysis of market results and a report by the PJM Market Monitoring Unit (MMU), PJM stakeholders will vote on whether to keep the combined market.

During Phase 4, PJM operated three Spinning Reserve Markets: one for the Mid-Atlantic Region, one for the Western Region and one for the ComEd Control Zone. During Phase 5, PJM operated a fourth Spinning Reserve Market for Dominion.

The analysis treats each of the two Regulation Markets and each of the three Spinning Reserve Markets separately during Phase 4. The market analysis treats each of the two Regulation Markets separately during the May 1 through July 31 component of Phase 5 (Phase 5-a), and as a single Regulation Market during the August 1 through December 31 component of Phase 5 (Phase 5-b). Each of the four Spinning Reserve Markets is treated separately for the entire Phase 5 period.

Overview – Regulation and Spinning Reserve Markets

The MMU has reviewed structure, conduct and performance indicators for the identified Regulation Markets. The MMU concludes that the Regulation Markets functioned effectively, except for some minor problems of insufficient regulation supply shortly after the start of Phase 5 and during times of minimum generation. The Regulation Markets produced competitive results throughout calendar year 2005 based on the regulation market-clearing price. The Regulation Market prices reflected the fact that offers in the Western Region were capped during Phase 4 and that the offers of two large participants, AEP and Dominion, were capped at cost plus a margin throughout Phase 5, in both cases because the Western Region Regulation Market was determined to be not structurally competitive.

7 During the five-month period May 1, 2004, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

The MMU has reviewed structure, conduct and performance indicators for the identified Spinning Reserve Markets. The MMU concludes that the Spinning Reserve Markets functioned effectively. The Spinning Reserve Markets produced competitive results throughout calendar year 2005 based on the spinning market-clearing price. The Spinning Reserve Market prices reflected the fact that all offers were capped at cost plus a margin because the markets have been determined to be not structurally competitive.

The Regulation Markets

The structure of the Mid-Atlantic Region and Western Region Regulation Markets was evaluated and the MMU concluded that these markets are not structurally competitive as they are characterized by a combination of one or more structural elements including high levels of supplier concentration, high individual company market shares, significant hours with pivotal suppliers and inelastic demand. The structure of the Combined Regulation Market was also evaluated based on the five months of available data and the MMU concluded that this market is characterized by lower levels of concentration, smaller market shares, a smaller number of hours with pivotal suppliers and inelastic demand. The conduct of market participants within these market structures has been consistent with competition consistent with existing offer capping, and the market performance results have been competitive.

- **Mid-Atlantic Region.** The Regulation Market in the PJM Mid-Atlantic Region was cleared based on participants' price offers during Phases 4 and 5-a. All suppliers were paid the market-clearing price, which is a function of the supply curve and PJM-defined demand. The supply curve consists of offered and eligible MW and the associated offer prices which are a combination of unit-specific offers plus opportunity cost (OC) as calculated by PJM.[8]

- **Western Region.** The Regulation Market in the Western Region during Phase 4 was cleared based on participants' cost-based offers. The cost-based regulation offers are defined to be the unit-specific incremental cost of providing regulation plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM. During Phase 5-a, the market was cleared using a combination of price-based offers and cost-based offers. In Phase 5, Dominion and AEP were required to make cost-based offers based on their dominant position in the market while other participants made price offers.

- **PJM Combined Regulation Market.** During the trial period for the PJM Combined Regulation Market, the market was cleared using a combination of price-based offers and cost-based offers. Dominion and AEP were required to make cost-based offers based on their dominant position in the market while other participants made price offers.

Market Structure

- **Demand.** Demand for regulation is determined by PJM based on an evaluation of the regulation required in order to meet reliability objectives. Required regulation remained constant for each control region throughout 2005 except for two periods during which a temporary adder was implemented at the direction of PJM.

8 As used here, the term, "opportunity cost" (OC), refers to the estimated lost opportunity cost (LOC) that PJM uses to create a supply curve on an hour-ahead basis. The term, "lost opportunity cost," refers to opportunity costs included in payments to generation owners.

- **Supply.** The supply of offered and eligible regulation in the PJM Mid-Atlantic Region was generally both stable and adequate, with an average 1.92 ratio of regulation supply offered and eligible to the hourly regulation requirement during Phases 4 and 5-a. While the average ratio of hourly regulation supply offered and eligible to regulation required was 1.64 for the Western Region during Phases 4 and 5-a, at times an inadequate supply of regulation was offered and eligible to participate in the market on an hourly basis in the Western Region. The average ratio of hourly regulation supply offered and eligible to regulation required was 1.88 for the PJM Combined Regulation Market during Phase 5-b.

Concentration of Ownership

- **Mid-Atlantic Region.** During Phase 4 and Phase 5-a, the PJM Mid-Atlantic Region Regulation Market for eligible regulation had an average Herfindahl-Hirschman Index (HHI)[9] of 1751 which is classified as "moderately concentrated."[10] Less than 1 percent of the hours had an eligible regulation HHI above 2500. There were two suppliers with market shares greater than, or equal to, 20 percent. Seven percent of the hours had a single pivotal supplier, 48 percent of the hours had two pivotal suppliers and 88 percent of the hours had three pivotal suppliers.

- **Western Region.** During Phase 4 and Phase 5-a, the Western Region Regulation Market for eligible regulation had an average HHI of 2802 which is classified as "highly concentrated" and 58 percent of the hours had an HHI above 2500. There was a single pivotal supplier in 62 percent of the hours. One hundred percent of the hours had two pivotal suppliers.

- **PJM Combined Regulation Market.** During Phase 5-b, the PJM Combined Regulation Market had an average HHI of 1079 which is classified as "moderately concentrated." No suppliers had market shares greater than, or equal to, 20 percent. During 1 percent of hours, there was a single pivotal supplier. During 6 percent of hours, there were two pivotal suppliers. During 29 percent of the hours, there were three pivotal suppliers. For all units except CTs, during 5 percent of hours, there was a single pivotal supplier, during 23 percent of hours, there were two pivotal suppliers and during 68 percent of the hours, there were three pivotal suppliers.

Market Conduct

- **Offers.** The offer price is the only component of the total regulation offer price provided by the unit owner and is applicable for the entire operating day. The regulation offer price is subject to a $100 per MWh offer cap in the Mid-Atlantic Region, was subject to offer capping in Phase 4 in the Western Region and was subject only to a $100 per MWh offer cap in Phase 5 in the Western Region, with the exception of the dominant suppliers, Dominion and AEP, whose offers were capped at marginal cost plus $7.50 per MWh plus opportunity cost. The average MW-weighted offer price for regulation in the PJM Mid-Atlantic Region during Phases 4 and 5-a was $15.63. The average MW-weighted offer price for regulation in the Western Region Regulation Market during Phases 4 and 5-a was $7.73. For the PJM Combined Regulation Market during Phase 5-b, the average MW-weighted offer price for regulation was $16.29.

9 See Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
10 The market structure metrics reported in this summary are based on regulation capacity that is both offered to the market and is eligible to provide regulation.

Market Performance

- **Price.** For the entire PJM regional transmission organization (RTO) from January 1, 2005, to December 31, 2005, the average price per MWh (regulation market-clearing price) associated with meeting PJM's demand for regulation was $49.73. For the PJM region during Phases 4 and 5-a, the average price per MWh for regulation was $36.39. For the Western Region Regulation Market during Phases 4 and 5-a, the average price per MWh for regulation was $42.64. For the PJM Combined Regulation Market during Phase 5-b, the average price per MWh was $64.03.

The Spinning Reserve Markets

The structure of each of the Spinning Reserve Markets has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated as markets with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin and opportunity cost. The conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Prices for spinning in the PJM Mid-Atlantic Region, the ComEd Control Zone, the Western Region and Dominion are market-clearing prices determined by the supply curve and PJM-defined demand. The cost-based spinning offers are defined to be the unit-specific incremental cost of providing spinning reserve plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM.

Market Structure

- **Demand.** Computed in accordance with the specific spinning reserve requirements, the average MW spinning requirement was: 1,091 MW for the PJM Mid-Atlantic Region; 217 MW for the ComEd Spinning Zone; 437 MW for the Western Region; and 5 MW for the Southern Spinning Reserve Zone (May to December only).

- **Supply.** For the PJM Mid-Atlantic Region, the offered and eligible excess supply ratio was 1.15. For the Western and Southern Regions, the ratio was 1.76. For the ComEd Control Zone, the ratio was 1.21.

- **Concentration of Ownership.** In 2005, market concentration was high in the Tier 2 Spinning Reserve Market. The average offered and eligible Spinning Reserve Market HHI for the PJM Mid-Atlantic Region throughout 2005 was 2940. The average Spinning Reserve Market HHI for the Western Region was 4593. The average Spinning Reserve Market HHI for ComEd Control Zone was 8844. The average Spinning Reserve Market HHI for Dominion was 10000.

Market Performance

- **Price.** Load-weighted, average price associated with meeting the PJM system demand for Tier 2 spinning reserve throughout 2005 was $14.41 per MW, a $0.45 per MW decrease from 2004. The load-weighted, average price in the PJM Mid-Atlantic Region for Phases 4 and 5 was $15.44 per MW. The load-weighted, average price for spinning reserve in the ComEd Control Zone during Phases 4 and 5 was $12.73. The load-weighted, average price for spinning in the Western Control Zone during Phases 4 and 5 was $13.23. The load-weighted, average price for spinning in Dominion during Phase 5 was $13.08.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition. The MMU will make a recommendation in the near future as to whether the consolidation has resulted in a market that is structurally competitive. The market continues to be based on price offers for most sellers and all sellers are paid a market-clearing price based on offers plus opportunity costs. The result of this design has been a competitive outcome and consistent with competitive offers from all participants whether offer-capped or not. The marginal costs of providing regulation have been clearly defined and are consistent with the offers that would be made if the suppliers were behaving competitively.

PJM's Spinning Reserve Markets have worked effectively with offers based on marginal costs plus a margin and with all participants paid a market-clearing price based on the marginal offer including opportunity costs, despite the fact that these markets are characterized by high levels of seller concentration and inelastic demand.

The benefits of markets are realized under this approach to ancillary service markets. Even in the presence of structurally non-competitive markets, there are transparent, market-clearing prices based on competitive offers that account explicitly and accurately for opportunity costs. PJM should continue to consider whether additional ancillary service markets need to be defined in order to ensure that the market is compensating suppliers for services when appropriate.

Regulation Markets

Regulation Market Structure

Two major changes affected the structure of the Regulation Market in 2005. The first was the integration of Dominion into the Western Region Regulation Market on May 1, 2005. The second was the implementation of the PJM Combined Regulation Market on August 1, 2005.

Demand

Demand for regulation does not change with price (is price inelastic). The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand will be referred to in this report as required regulation.

The PJM Mid-Atlantic Region has different regulation requirements for on-peak hours and off-peak hours. The regulation requirement for the peak period is 1.1 percent of the peak-load forecast; for the off-peak period, it is 1.1 percent of the valley-load forecast.[11] During Phases 4 and 5-a, PJM Mid-Atlantic Region regulation requirements ranged from 226 MW of regulation capability for off-peak periods to 649 MW for on-peak periods. The average required regulation was 434 MW.

In the Western Region, the regulation requirement was 1.0 percent of the peak forecast load and did not vary between on-peak and off-peak periods. During Phases 4 and 5-a, the requirement ranged from 320 MW to 771 MW, averaging 517 MW.

During Phase 5-b, the PJM Mid-Atlantic Region and the Western Region Regulation Markets were combined into the PJM Combined Regulation Market. The regulation requirement for this combined market was defined to equal the sum of the separate regulation requirements for each region. During Phase 5-b, the regulation requirement ranged from 662 MW to 1,404 MW, averaging 978 MW.

Although the required regulation specification remained constant for each control region throughout 2005, a temporary adder was implemented at the direction of PJM for two periods. As a result, regulation was purchased in addition to the full regulation requirement. On October 23, 2004, in response to problems after the integration of the ComEd Control Zone into the Western Region, required regulation was increased by 75 MW for each regulation zone. This regulation adder was subsequently reduced until regulation was returned to its base requirement on February 11, 2005.

11 See "PJM Manual for Scheduling Operations, M-11," Revision 25 (August 19, 2005), p. 51.

On April 15, 2005, in response to a persistent problem with frequency excursions, a 100 MW increment was added to the regulation demand for both the Mid-Atlantic and Western Regions. It was phased out and then eliminated on May 14, 2005. Table 6-1 contains a list of regulation adder amounts by date.

Table 6-1 - Temporary regulation adder: October 23, 2004, to May 15, 2005

Regulation Adder Date	Change in Regulation MW per Control Zone	Total Regulation Adder (MW) per Control Zone
23-Oct-04	75	75
29-Oct-04	(75)	0
01-Nov-04	75	75
11-Nov-04	100	175
17-Dec-04	(50)	125
07-Jan-05	(25)	100
14-Jan-05	(25)	75
26-Jan-05	(25)	50
04-Feb-05	(25)	25
11-Feb-05	(25)	0
15-Apr-05	100	100
06-May-05	(25)	75
08-May-05	(75)	0
12-May-05	50	50
14-May-05	(50)	0

The temporary additional regulation requirements between mid-April and mid-May reflected an effort by PJM to solve simultaneous problems of insufficient regulation in the Western Region Regulation Market, particularly during off-peak hours, and frequency excursions that impacted PJM's compliance requirement for CPS2.[12]

Regulation obligation is determined hourly for each load-serving entity (LSE) by applying the real-time load ratio share (adjusted for scheduled load responsibility) to the actual amount of regulation assigned for that hour adjusted for any bilaterals and self-supply. The hourly regulation charge for each LSE is equal to the hourly regulation market-clearing price (RMCP) multiplied by the MW of regulation purchased from the market, plus the LSE's percentage share of any opportunity cost incurred by generation owners over and above the RMCP, plus the LSE's percentage share of any unrecovered costs incurred by those units called on by PJM for the sole purpose of providing regulation.

Supply

The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called assigned regulation. Assigned regulation is selected from regulation that is both offered and eligible.

12 See Appendix F, "Ancillary Service Markets," for additional information on area control error (ACE) control and control performance standard (CPS).

Regulation capability represents the total volume of regulation capability reported by resource owners based on unit characteristics.

Regulation offered represents the level of regulation capability actually offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers may be submitted on a daily basis and these daily offers may be modified on an hourly basis.

Regulation offered and eligible represents the level of regulation capability actually offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit will be included in regulation offered based on the daily offer and availability status, but that regulation capability will not be eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. (The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market software.) As another example, the regulation capability of a unit will be included in regulation offered if the owner of a unit offers regulation, but that regulation capability will not be eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit will be included in regulation offered but that regulation capability will not be eligible if the unit is not operating, unless the unit is a combustion turbine that meets specific operating parameter requirements.

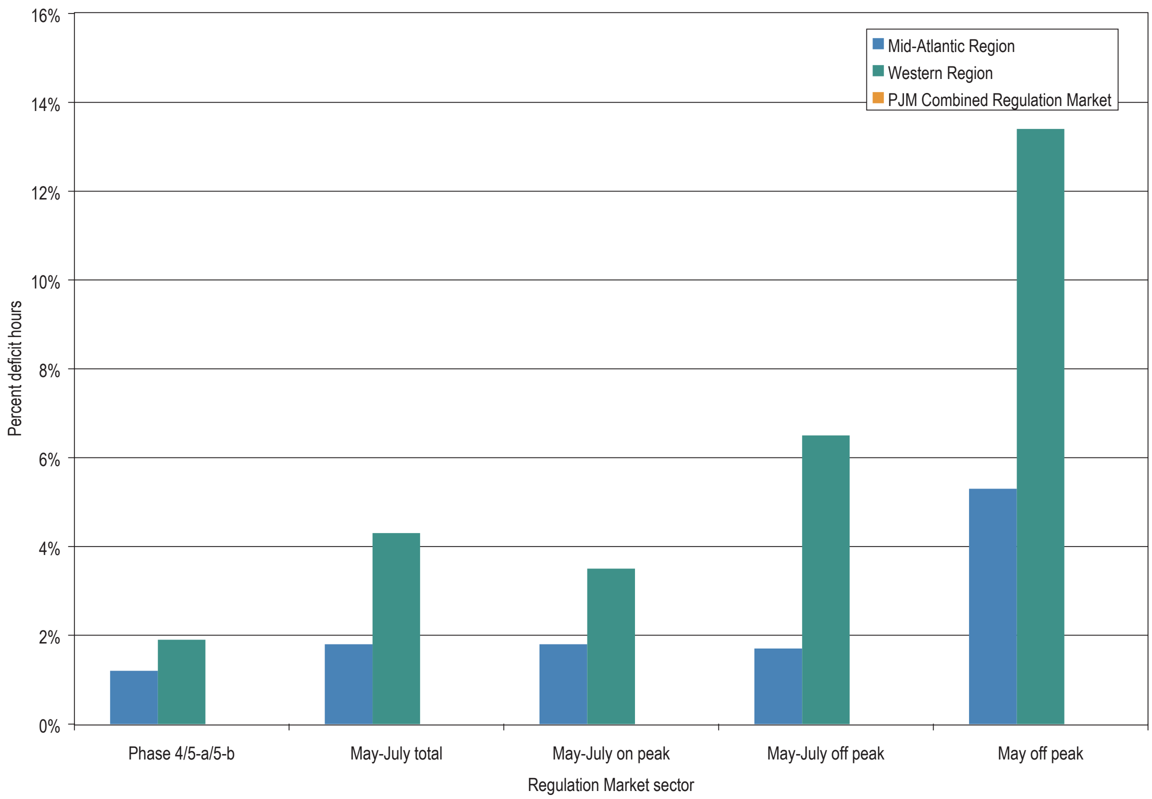
Only those offers which are eligible to provide regulation in an hour are part of supply for that hour, and only those offers are considered for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the regulation market-clearing mechanism to provide regulation service for a given hour.

While the average regulation supply-to-requirement ratio of offered regulation in the Western Region Regulation Market during Phase 5-a was generally adequate at 1.70, the situation was more complicated than the supply-to-requirement ratio indicates. Regulation capacity was always adequate in the sense that the total reported capability was adequate.[13] Occasionally, however, PJM dispatchers had to redispatch generation uneconomically to satisfy reliability requirements. PJM encountered some difficulty with insufficient regulation supply in the Western Regulation Zone during Phase 5-a. Shortly after the Dominion integration on May 1, 2005, there was at times an inadequate supply of regulation that was offered and eligible to participate in the market on an hourly basis. This situation was most acute in the Western Region Regulation Market in May 2005 during off-peak periods when market solutions resulted in deficits 13.6 percent of the time and occasional off-peak hourly price spikes. (See Figure 6-1.) These higher than normal deficits generally occurred during off-peak hours when regulation-capable units were unavailable to regulate because they were not operating. In May, PJM frequently operated under minimum generation conditions, especially during off-peak hours. The combination of a regulation deficit and minimum generation conditions required dispatchers to balance the need for more regulation with the need for less generation. Dispatchers at times chose to operate with regulation deficits. This situation improved during June (deficits in 5.3 percent of all periods) and was resolved in July when the deficit percentage returned to its overall Phases 4 and 5-a average.

13 See "Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned," in Appendix F, "Ancillary Service Markets," for a definition of capacity, availability and supply.

Figure 6-1 compares the percentage of regulation deficit hours across several Regulation Market periods, including all of 2005, Phase 5 only, off-peak and on-peak hours and off-peak hours in May. The abnormally high deficits that occurred in the Western Region particularly during off-peak hours in early May are clearly indicated.

Figure 6-1 - Regulation deficit analysis: Calendar year 2005



Regulation deficits in the west were reduced during June and returned to normal in July. Also indicated in Figure 6-1 is the extent to which regulation deficits were all but eliminated after the PJM Combined Regulation Market. There was only one period of regulation deficit in the PJM Combined Regulation Market during Phase 5-b. This deficit does not show up in Figure 6-1 because the percentage of regulation deficit hours rounds to zero percent.

Concentration of Ownership

Market Structure Definitions

The market structure analysis follows the Commission logic specified in the AEP order.[14] The logic of the delivered price test is followed by calculating market share, HHI and pivotal supplier metrics for each market configuration.[15] The analysis presented here differs in two ways from the Commission's delivered price test. The delivered price test would start with the universe of regulation offered and eligible and then limit the analysis to those offered and eligible units that could provide regulation at less than or equal to 1.05 times the clearing price. The analysis here uses a proxy for the 1.05 times the clearing price definition used to define the relevant market. In PJM, the supply of regulation generally consists of two relatively distinct segments: an all units except combustion turbine (CT) segment (consisting of steam and hydroelectric units) and a CT segment. While steam, hydroelectric and CT units can and do provide regulation, the steam/ hydroelectric segment is generally lower cost and is relatively homogeneous while the CT segment is generally significantly higher cost and similarly relatively internally homogeneous. Rather than directly applying the 1.05 times the clearing price market definition, the analysis here focuses separately on the steam/hydroelectric and the CT portions of the market. The steam/hydroelectric segment of the market is used in place of including only sellers that offer for a price less than or equal to the clearing price times 1.05 when a steam/hydroelectric unit is marginal, although the segment approach results in a substantially larger market definition. The CT segment is similarly used in place of including only sellers that offer for a price less than or equal to the clearing price times 1.05 when a CT unit is marginal, although again the segment approach probably results in a larger market definition. The data are presented including all units, all units except CTs (steam and hydroelectric) and CTs. In addition, the analysis here includes the results of the one, two and three pivotal supplier tests.

The analysis here includes all regulation provided by each supplier and made offered and eligible. While the market structure results are reported for regulation offered, this is not directly relevant to a determination of whether a market structure is competitive. Regulation must be both offered and eligible in an hour in order for it to be part of the market. This is termed economic capacity under the delivered price test.

The delivered price test may also be applied using available economic capacity, or gross supply by participant net of their load obligation. The fact that suppliers have load obligations may affect their incentives to exercise market power although not unambiguously. However, as the amount of load that will be served by the integrated utilities in the future is unknown given the unknown extent of retail competition, a reasonable approach is to evaluate the entire regulation supply, or economic capacity, as is done here.

The Commission's AEP order indicates that failure of any one of the specified tests is adequate for a showing of market power including tests based on market concentration, market share and pivotal supplier analyses. The analysis presented here goes further in order to analyze the significance of excess supply. The MMU applies the pivotal supplier test using one, two and three pivotal suppliers. In addition, when there are hours with one, two or three pivotal suppliers, the analysis also examines the frequency with which individual generation owners are in the pivotal group. If the hours that fail a pivotal supplier test have the same pivotal supplier(s) for a significant proportion of the hours, that information can be used to identify dominant suppliers.

14 107 FERC ¶ 61,018 (2003) ("AEP Order"), 108 FERC ¶ 61,026 (2004)("Order on Rehearing").
15 AEP Order at 105 *et seq.*

The pivotal supplier tests represent an analytical approach to the issue of excess supply. Excess supply, by itself, is not necessarily adequate to ensure a competitive outcome. A monopolist could have substantial excess supply but the monopolist would not be expected to change its market behavior as a result. The same logic applies to a small group of dominant suppliers. However, if there is adequate supply without the three dominant suppliers to meet the demand, then the market can reasonably be deemed competitive.

PJM Mid-Atlantic Regulation Market – Phases 4 through 5-a

During Phases 4 through 5-a, in the Regulation Market in the Mid-Atlantic Region, the offer capability was 2,408 MW.[16] The level of regulation resources offered on an hourly level and the level of regulation resources both offered and eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2005 the average hourly offer level was 1,128 MW or 47 percent of offer capability while the average hourly eligible offer level was 835 MW or 35 percent of offer capability.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 2.60 for the PJM Mid-Atlantic Region during Phases 4 and 5-a. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period. Based upon regulation offered and eligible, this ratio averaged 1.92. The average regulation requirement for the PJM Mid-Atlantic Region during 2005 was 434 MW.

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible, and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 2064 to a minimum of 1088 with an average value of 1510. Based upon regulation offered and eligible, HHI values ranged from a maximum of 2787 to a minimum HHI of 1190, with an average value of 1751. Less than 1 percent of hours had an eligible regulation HHI above 2500. Based upon regulation assigned, HHI values ranged from a maximum of 9690 to a minimum HHI of 1118. The average HHI value for regulation assigned was 2260. Thirty-one percent of hours had an assigned regulation HHI above 2500. Table 6-2 summarizes the January 2005 through July 2005 PJM Mid-Atlantic Region Regulation Market HHIs.

Table 6-2 - PJM Mid-Atlantic Region Regulation Market hourly HHI: Phases 4 and 5-a

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	1088	1510	2064	0%
Eligible	1190	1751	2787	0%
Assigned	1118	2260	9690	31%

As noted above, regulation supply in PJM is bifurcated into the combustion turbine (CT) segment and the all units except CTs segment because, while some CTs provide regulation, they are very expensive to operate solely to provide regulation. In order to approximate the delivered price test approach, the Regulation Market HHI is reported with and without CTs. (See Table 6-3.) In the PJM Mid-Atlantic Region, HHIs are slightly lower without CTs because the CTs are disproportionately owned by the company with the largest market share.

16 Offer capability is defined as the maximum daily offer volume for each offering unit during the period without regard to the actual availability of the resource.

Table 6-3 - PJM Mid-Atlantic Region Regulation Market hourly HHI (All units except CTs): Phases 4 and 5-a

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	1078	1475	2354	0%
Eligible	1183	1718	2941	0%
Assigned	1118	2266	9690	31%

During Phases 4 and 5-a, two suppliers had market shares greater than, or equal to, 20 percent based on regulation offered and eligible. For the market segment excluding CTs, two suppliers had market shares greater than, or equal to, 20 percent based on regulation offered and eligible.

During Phases 4 and 5-a, 7 percent of the hours failed the single pivotal supplier test for offered and eligible supply in the PJM Mid-Atlantic Region's market.[17] This means that, during the seven-month period, for 7 percent of the hours the total regulation requirement could not be met in the absence of the largest supplier. Forty-eight percent of the hours failed the two pivotal supplier test. This means that, during 48 percent of the hours, the total regulation requirement could not be met in the absence of the two largest suppliers. Eighty-eight percent of the hours failed the three pivotal supplier test. This means that, during 88 percent of the hours, the total regulation the regulation requirement could not be met in the absence of the three largest suppliers.

For the market segment excluding CTs, the percentage of one pivotal supplier hours in the eligible Regulation Market increases from 7 percent to 10 percent, the percentage of two pivotal supplier hours increases from 48 percent to 52 percent and the percentage of three pivotal supplier hours increases from 88 percent to 89 percent. Table 6-4 summarizes the PJM Mid-Atlantic Region Regulation Market pivotal supplier statistics for Phases 4 and 5-a. The pivotal supplier statistics are also presented for all regulating units except CTs. (See Table 6-5.) Three companies are pivotal more than 75 percent of the three pivotal supplier intervals for all units, and for the all units except CTs segment.

Table 6-4 - PJM Mid-Atlantic Region Regulation Market pivotal supplier statistics: Phases 4 and 5-a

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	0%	7%
2 pivotal	3%	48%
3 pivotal	35%	88%

Table 6-5 - PJM Mid-Atlantic Region Regulation Market pivotal supplier statistics (All units except CTs): Phases 4 and 5-a

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	0%	10%
2 pivotal	9%	52%
3 pivotal	52%	89%

17 The pivotal supplier results are provided for all offered regulation as additional information although these results are not directly relevant to the market structure analysis.

Based on these market structure results, the MMU concludes that the market structure of the PJM Mid-Atlantic Region Regulation Market during Phases 4 and 5-a can no longer be considered to be consistent with a competitive outcome. The combination of two market participants with market shares greater than, or equal to, 20 percent and the pivotal supplier results are not consistent with a competitive structure. The market in the PJM Mid-Atlantic Region was operated by PJM as a competitive market prior to the Combined Regulation Market.

Western Region Regulation Market – Phases 4 and 5-a

During Phases 4 and 5-a, in the Western Region Regulation Market, the submitted offer capability was 2,267 MW. The level of resources offered on an hourly level and the level of regulation resources both offered and eligible to participate on an hourly level in the Regulation Market were lower than the submitted regulation offer capability. Between the beginning of Phase 4 and the end of Phase 5-a, the average hourly offer level was 938 MW or 41 percent of the submitted capability, while the average hourly eligible offer level was 847 MW or 37 percent of the submitted capability.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 1.81 for the Phases 4 and 5-a Western Region Regulation Market. Based upon regulation offered and eligible, this ratio averaged 1.64. The average regulation requirement for the Phases 4 and 5-a Western Region Regulation Market was 517 MW.[18]

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 4357 to a minimum of 1748 with an average value of 2730. Fifty-eight percent of hours had an offered regulation HHI above 2500. Based upon regulation offered and eligible, HHI values ranged from a maximum of 4810 to a minimum HHI of 1757, with an average value of 2802. Fifty-eight percent of hours had an eligible regulation HHI above 2500. Based upon regulation assigned, HHI values ranged from a maximum of 7162 to a minimum HHI of 1698. The average HHI value for regulation assigned was 2973. Sixty-four percent of hours had an assigned regulation HHI above 2500. Table 6-6 summarizes the January through July 2005 Western Region Regulation Market HHIs.

Table 6-6 - PJM Western Region Regulation Market hourly HHI: Phases 4 and 5-a

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	1748	2730	4357	58%
Eligible	1757	2802	4810	58%
Assigned	1698	2973	7162	64%

18 See Appendix F, "Ancillary Service Markets," for additional detail on the regulation requirements.

For the market segment excluding CTs, HHIs in the Western Region Regulation Market are somewhat higher. (See Table 6-7.)

Table 6-7 - PJM Western Region Regulation Market hourly HHI (All units except CTs): Phases 4 and 5-a

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	1859	2960	4973	60%
Eligible	1856	3029	5249	62%
Assigned	1738	2984	7162	65%

During Phases 4 and 5-a, one supplier had a market share greater than, or equal to, 20 percent based on offered and eligible regulation. For the market segment excluding CTs, one supplier had a market share greater than, or equal to, 20 percent based on offered and eligible regulation.

During Phases 4 through 5-a, 62 percent of the hours failed the single pivotal supplier test for offered and eligible supply in the Western Region Regulation Market. This means that, during the seven-month period, the total regulation requirement could not be met for 62 percent of the hours in the absence of the largest supplier. One hundred percent of the hours failed the two pivotal supplier test. This means that, during 100 percent of the hours, the total regulation requirement could not be met in the absence of the two largest suppliers. One hundred percent of the hours failed the three pivotal supplier test. This means that, during 100 percent of the hours, the total regulation requirement could not be met in the absence of the three largest suppliers. Table 6-8 summarizes the Western Region Regulation Market pivotal supplier statistics for Phases 4 through 5-a.

Table 6-8 - PJM Western Region Regulation Market pivotal supplier statistics: Phases 4 and 5-a

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	30%	62%
2 pivotal	100%	100%
3 pivotal	100%	100%

Table 6-9 presents pivotal supplier statistics for the Western Region regulation pool for all units except CTs. Eighty-eight percent of hours fail the one pivotal supplier test. In both the all units and all units except CTs market segments the same company that was the one pivotal supplier was also pivotal for more than 95 percent of the hours in which two and three suppliers were pivotal.

Table 6-9 - PJM Western Region Regulation Market pivotal supplier statistics (All units except CTs:): Phases 4 and 5-a

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	69%	88%
2 pivotal	100%	100%
3 pivotal	100%	100%

Based on these market structure results, the MMU concludes that the market structure of the Western Region Regulation Market was not consistent with a competitive outcome. The Regulation Market in the Western Region was operated by PJM, with the two dominant suppliers offer-capped, as a market with market-clearing prices during Phases 4 and 5-a.

PJM Combined Regulation Market – Phase 5-b

The PJM Combined Regulation Market during Phase 5-b was comprised of the PJM Western Region (the ComEd, AEP, DAY, Dominion, DLCO and AP Control Zones) and the PJM Mid-Atlantic Region. For the Phase 5-b PJM Combined Regulation Market, the submitted capability was 5,491 MW. The average hourly offer level was 2,370 MW while the average hourly eligible offer level was 1,841 MW.

The ratio of the hourly regulation supply offered to the hourly regulation requirement averaged 2.42. Based upon regulation offered and eligible, this ratio averaged 1.88. The average regulation requirement for the Phase 5-b PJM Combined Regulation Market was 978 MW.

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 1331 to a minimum of 812 with an average value of 1001. Based upon regulation offered and eligible, HHI ranged from a maximum of 1562 to a minimum HHI of 866, with an average value of 1079. Based upon regulation assigned, HHI values ranged from a maximum of 2390 to a minimum of 878. The average HHI value for regulation assigned was 1299. Table 6-10 summarizes HHI results for the PJM Combined Regulation Market.

Table 6-10 - PJM Combined Regulation Market HHI: Phase 5-b

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	812	1001	1331	0 %
Eligible	866	1079	1562	0 %
Assigned	878	1299	2390	0 %

For the market segment excluding CTs, HHIs are essentially the same. (See Table 6-11.)

Table 6-11 - PJM Combined Regulation Market HHI (All units except CTs): Phase 5-b

	Minimum	Average	Maximum	Percent Hours > 2500
Offered	845	1016	1417	0 %
Eligible	891	1080	1659	0 %
Assigned	878	1301	2400	0 %

During Phase 5-b, in the PJM Combined Regulation Market, no suppliers had a market share greater than, or equal to, 20 percent for regulation offered and eligible. For the market segment excluding CTs, no suppliers had a market share greater than, or equal to, 20 percent for regulation offered and eligible. For the CT market segment, two suppliers had market shares in excess of 20 percent for regulation offered and eligible.

During Phase 5-b, 1 percent of the hours failed the single pivotal supplier test for offered and eligible supply in the PJM Combined Regulation Market. This means that, during the five-month period, the total regulation requirement could not be met for 1 percent of the hours in the absence of the largest supplier. Six percent of the hours failed the two pivotal supplier test. This means that, during 6 percent of the hours, the total regulation requirement could not be met in the absence of the two largest suppliers. Twenty-nine percent of the hours failed the three pivotal supplier test. This means that, during 29 percent of the hours, the total regulation requirement could not be met in the absence of the three largest suppliers. Table 6-12 summarizes the PJM Combined Regulation Market's pivotal supplier results for Phase 5-b. For all units including CTs the same company that was the one pivotal supplier for more than one-third of the one pivotal supplier intervals was also pivotal for more than 75 percent of the two pivotal supplier intervals and more than 80 percent of the hours in which two and three suppliers were pivotal. A second company was pivotal during more than 25 percent of the two pivotal and approximately 50 percent of three pivotal hours.

Table 6-12 - PJM Combined Regulation Market pivotal supplier statistics: Phase 5-b

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	0%	1%
2 pivotal	0%	6%
3 pivotal	1%	29%

Table 6-13 presents pivotal supplier statistics for the PJM Combined Regulation Market's segment for all units except CTs.

Table 6-13 - PJM Combined Regulation Market pivotal supplier statistics (All units except CTs): Phase 5-b

	Hours Offered (Percent)	Hours Eligible (Percent)
1 pivotal	0%	5%
2 pivotal	1%	23%
3 pivotal	14%	68%

For the market segment excluding CTs, the percentage of one pivotal supplier hours in the eligible Regulation Market increases from 1 percent to 5 percent, the percentage of two pivotal supplier hours increases from 6 percent to 23 percent and the percentage of three pivotal supplier hours increases from 29 percent to 68 percent. (See Table 6-13.) In the all units except CTs market segment, the same company that was the one pivotal supplier for more than two-thirds of the one pivotal supplier intervals was also pivotal for more than 80 percent of the two pivotal supplier intervals and more than 95 percent of the hours in which two and three suppliers were pivotal. A second company is pivotal during more than 60 percent of the two pivotal and three pivotal hours, while the third pivotal position is shared by three companies with an approximately equal frequency of occurrence.

The MMU will make a recommendation to PJM members in the near future regarding the structural competitiveness of this market.

Regulation Market Conduct

Regulation Offers

Generators wishing to participate in any of the PJM Regulation Markets must submit regulation offers for specific units by hour 1800 EPT of the day before the operating day. The regulation offer price is subject to a $100 per MWh offer cap in PJM control zones with the exception of the dominant suppliers Dominion and AEP whose offers are capped at marginal cost plus $7.50 per MWh plus opportunity cost. In the PJM Western Region during Phase 4, all regulation offers were capped at $7.50 per MWh plus the cost of providing regulation service because that market was determined to be not structurally competitive. As in any competitive market, regulation offers at marginal cost are considered to be competitive. In PJM, a $7.50 per MWh adder is considered to be consistent with competitive offers based on an analysis of historical offer behavior.

The offer price is the only component of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status (available, unavailable or self-scheduled); regulation capability; and high and low regulation limits. The Regulation Market is cleared on a real-time basis, and regulation prices are posted hourly throughout the operating day. The amount of self-scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made 30 minutes before each operating hour.

PJM's Regulation Markets are cleared hourly, based upon both offers submitted by the units and the hourly opportunity cost of each unit.[19] The effective offer price is the sum of the unit-specific offer and the opportunity cost. In order to clear the market, PJM ranks units which offer and are eligible to regulate by effective offer price and selects the lowest offers in order until the amount of regulation required for the hour is satisfied at least cost. The price that results is the RMCP, and the unit that sets this price is the marginal unit.

19 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. Opportunity cost is included in the market-clearing price.

Regulation Market Performance

Regulation Prices

Figure 6-2 shows both the daily average regulation market-clearing price and the opportunity cost component for the marginal units in the PJM Mid-Atlantic Region during Phases 4 and 5-a. Figure 6-3 shows the same data for the Western Region Regulation Market during Phases 4 and 5-a. Figure 6-4 shows the same data for the PJM Combined Regulation Market during Phase 5-b. All units chosen to provide regulation during Phases 4 and 5 received as payment the higher of the clearing price multiplied by the unit's assigned regulating capability, or the unit's regulation bid multiplied by its assigned regulating capability plus the individual unit's real-time opportunity cost.[20]

Regulation credits are awarded to generation owners that have either self-scheduled regulation or sold regulation into the market. Regulation credits for units self-scheduled to provide regulation are equal to the RMCP times the unit's self-scheduled regulating capability. Regulation credits for units that offered regulation into the market and were selected to provide regulation are the higher of the RMCP times the unit's assigned regulating capability, or the unit's regulation bid times its assigned regulating capability plus the opportunity cost that unit incurred. Although most units are paid RMCP times their assigned regulation MW, the RMCP is itself strongly dependent on the lost opportunity cost based upon forecast LMP calculated for the marginal unit during market clearing. This means that the total cost of regulation is very strongly dependent upon lost opportunity cost, which is dependent upon forecast LMP. Figure 6-2, Figure 6-3 and Figure 6-4 graph the RMCP against the estimated lost opportunity cost of the marginal unit (calculated at market clearance, adjusted for real-time deviations in LMP and averaged over the day). Most of the cost of regulation comes from the lost opportunity cost of the marginal unit. The rest of the RMCP is the unit's regulation offer. The average offer of the marginal unit for the PJM Mid-Atlantic Region during Phases 4 and 5-a was $15.33 per MW. The average offer of the marginal unit for the Western Region Regulation Market during Phases 4 and 5-a was $8.66 per MW. The average offer of the marginal unit for the PJM Combined Regulation Market during Phase 5-b was $13.16 per MW. In the PJM Mid-Atlantic Region Regulation Market during Phases 4 and 5-a, marginal unit lost opportunity cost (LOC) averaged 57 percent of the RMCP. In the Western Region Regulation Market during Phases 4 and 5-a, marginal unit LOC averaged 76 percent of RMCP. In the PJM Combined Regulation Market during Phase 5-b, marginal unit LOC averaged 79 percent of RMCP.

20 See "PJM Operating Agreement, Accounting, m28," Revision 27, Section 4, "Regulation Credits" (October 1, 2004), pp. 26-27. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and spinning. Real-time opportunity cost is calculated using real-time LMP.

Figure 6-2 - PJM Mid-Atlantic Region daily average regulation clearing price and adjusted estimated marginal unit opportunity cost: Phases 4 and 5-a

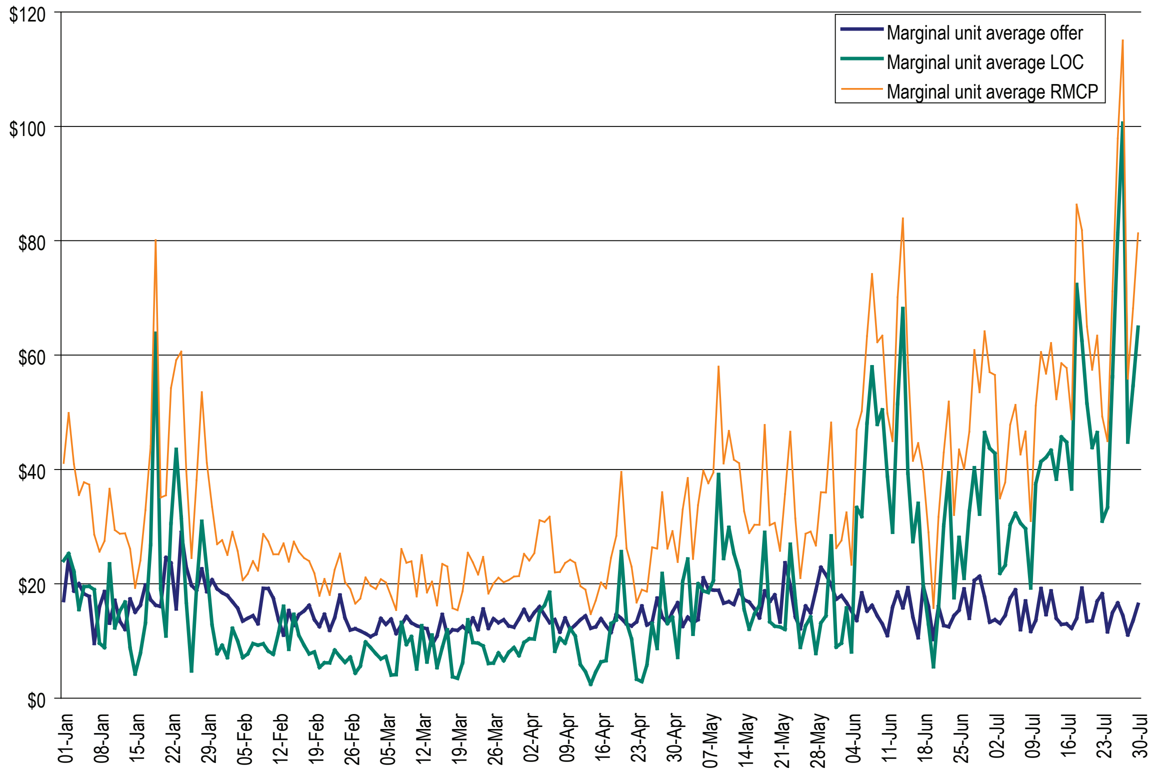


Figure 6-3 - PJM Western Region daily average regulation clearing price and adjusted estimated marginal unit opportunity cost: Phases 4 and 5-a

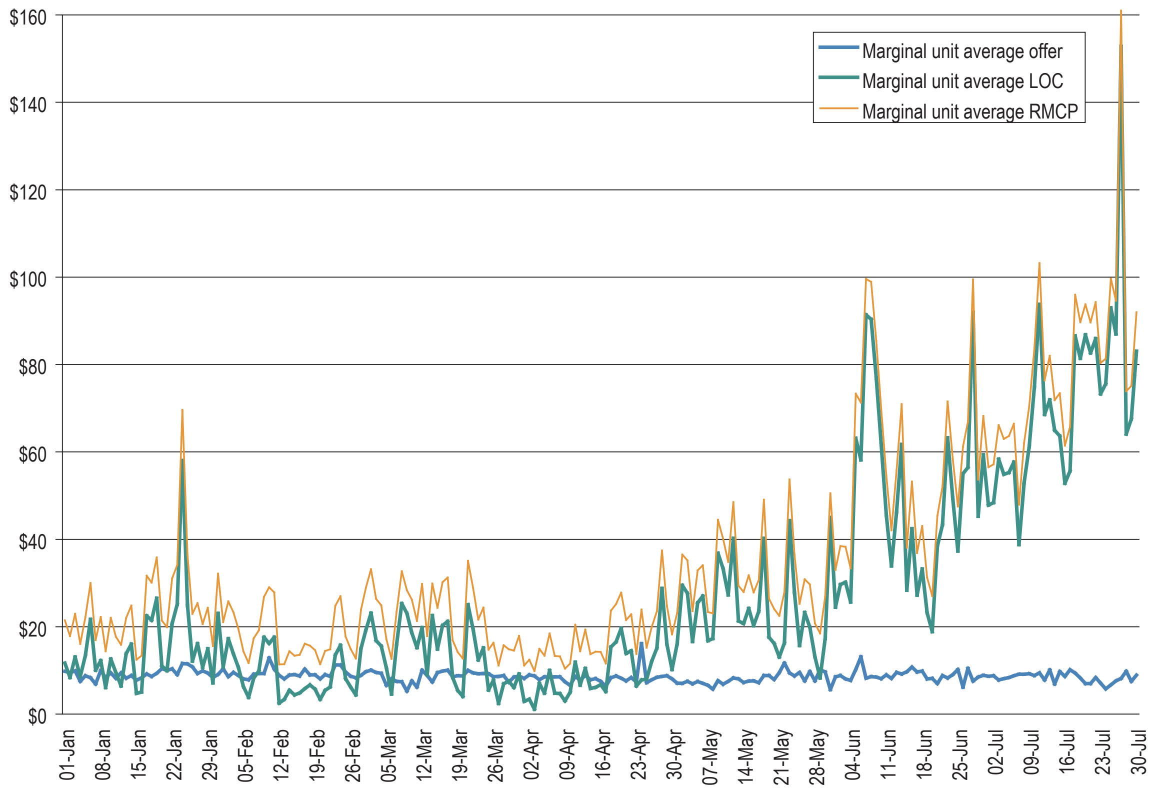


Figure 6-4 - PJM Combined Regulation Market daily average regulation clearing price and adjusted estimated marginal unit opportunity cost: Phase 5-b

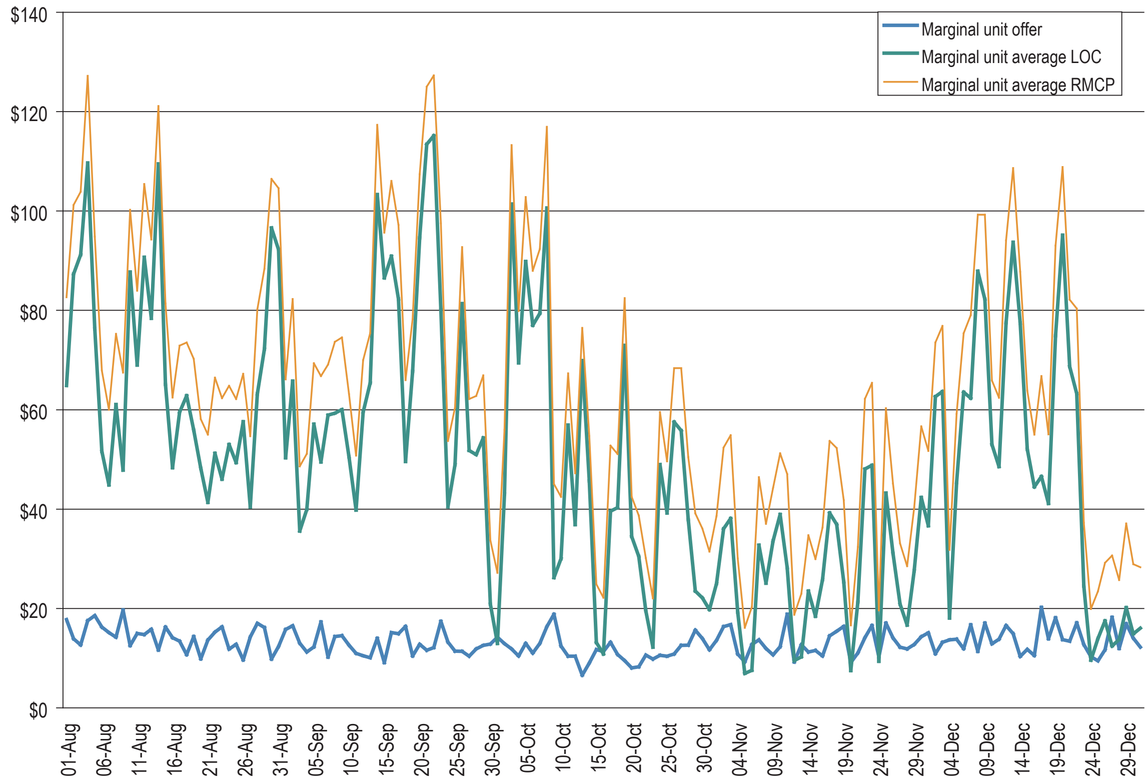


Figure 6-5, Figure 6-6 and Figure 6-7 compare the regulation price per MW to the regulation MW purchased for each of the Regulation Markets. As the regulation requirement is a linear function of daily forecast peak load in all markets, all three graphs show that despite considerable daily variation, the price of regulation and the demand for regulation increase or decrease together on a seasonal scale. System LMP increases with load because higher priced units must be dispatched to meet demand and those increases in system LMP cause the opportunity cost to rise by increasing the spread between LMP and the energy offers of the regulating units.

Figure 6-5 - PJM Mid-Atlantic Region daily regulation MW purchased vs. price per MW: Phases 4 and 5-a

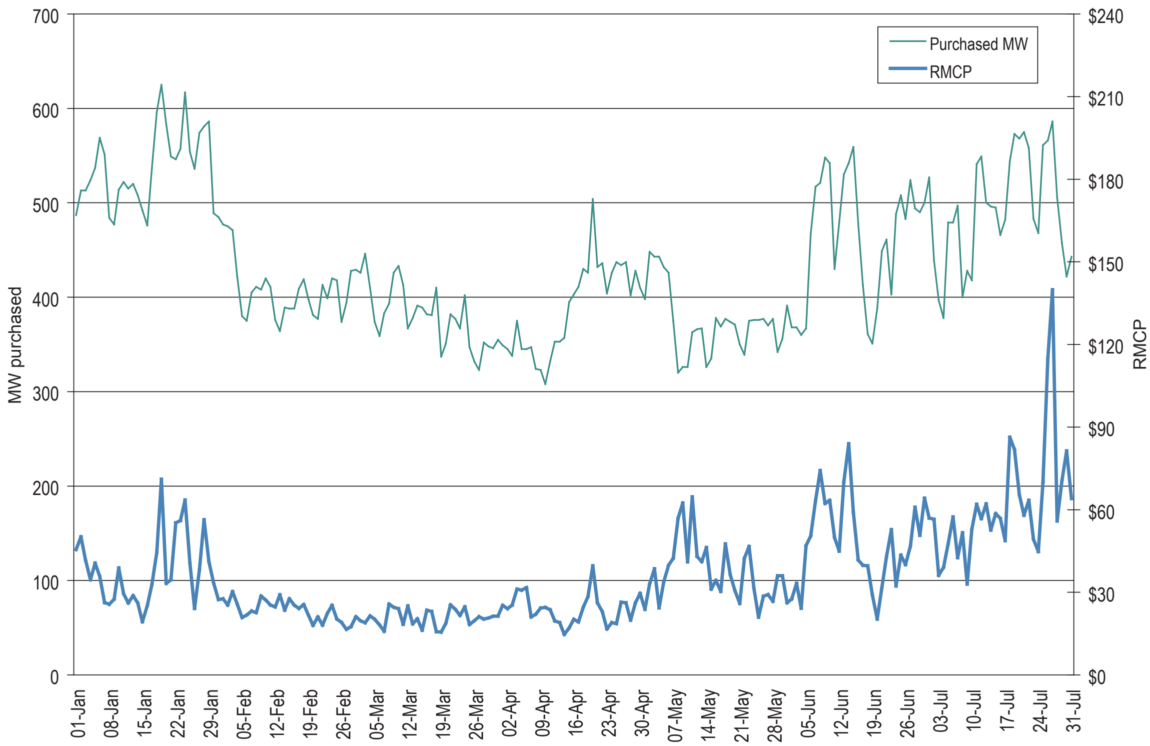


Figure 6-6 - PJM Western Region daily regulation MW purchased vs. price per MW: Phases 4 and 5-a

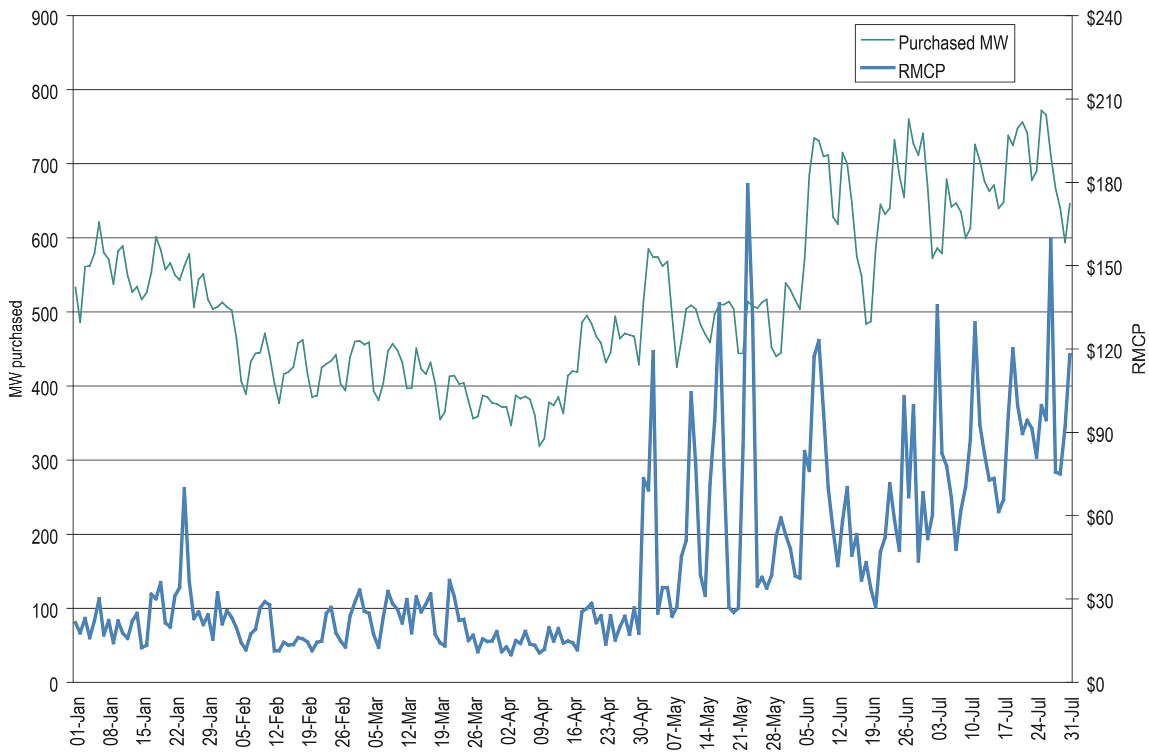
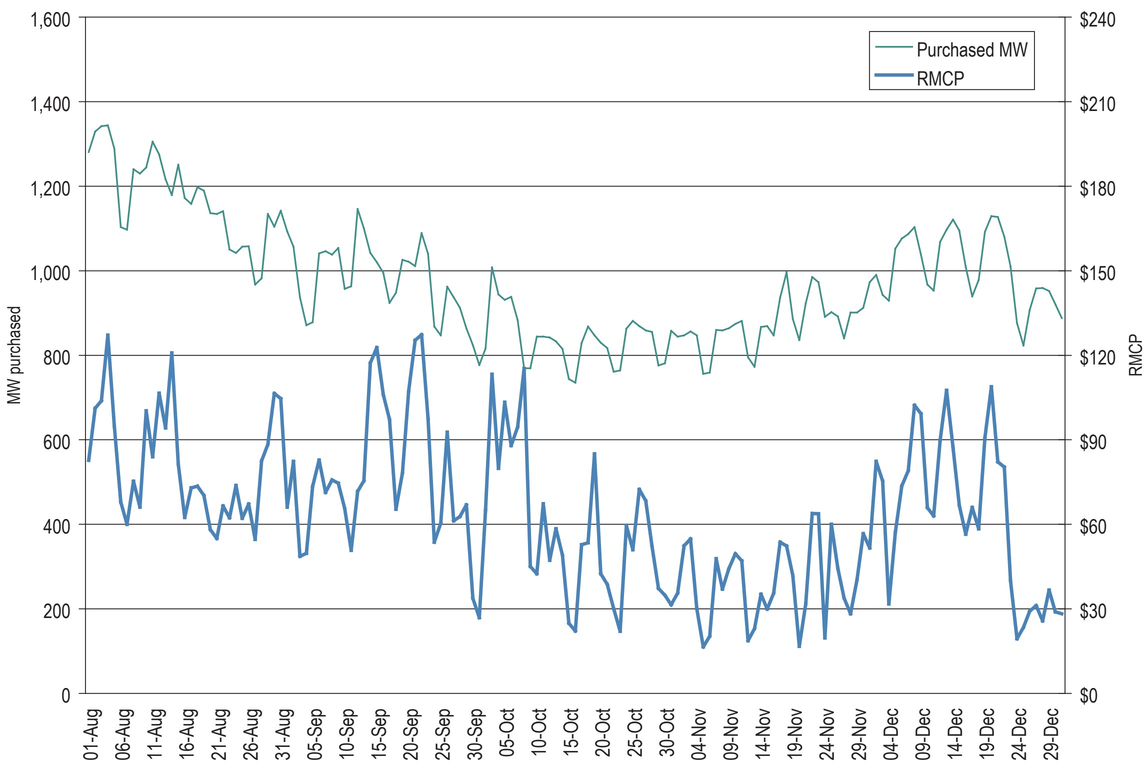


Figure 6-7 - PJM Combined Regulation Market daily regulation MW purchased vs. price per MW: Phase 5-b



Important exceptions to this general pattern occurred periodically in the Western Region after the integration of Dominion on May 1, 2005. (See Figure 6-6.) An hourly analysis of regulation MW purchased versus the regulation price reveals some extreme exceptions that resulted from deficits during off-peak hours and/or times of minimum generation events. A shortage of regulation-capable units (as existed in the Western Region in early May) combined with a minimum generation event required expensive combustion turbine units to be started to satisfy regulation requirements resulting in high clearing prices. Minimum generation events can cause shortages of regulation in the PJM Mid-Atlantic Region as well, but since the regulation requirement in the PJM Mid-Atlantic Region is lower during off-peak hours it is less likely. Overall, the inflexibility of demand and the shortage of available regulating units caused relatively wide price swings in the Western Region during Phase 5-a.

As Figure 6-5, Figure 6-6 and Figure 6-7 also show, regulation prices during calendar year 2005 were seasonally higher in January, remained lower and relatively stable from February through April, then began to increase and show high daily variability into October before moderating at the end of the year. The higher average summer prices reflect higher LMPs in the LOC portion of the marginal unit's RMCP for regulation. (See Figure 6-2, Figure 6-3 and Figure 6-4.) During a period of low prices, March and April, the LOC/RMCP ratio was 42 percent for the PJM Mid-Atlantic Region and 58 percent for the Western Region. During a period of high prices, August and September, the LOC/RMCP ratio was 83 percent for the PJM Combined Regulation Market.

Figure 6-8 illustrates the level of demand for regulation by month in 2005 and the corresponding level of regulation cost.

Figure 6-8 - Monthly regulation MW and regulation cost per MW: Calendar year 2005

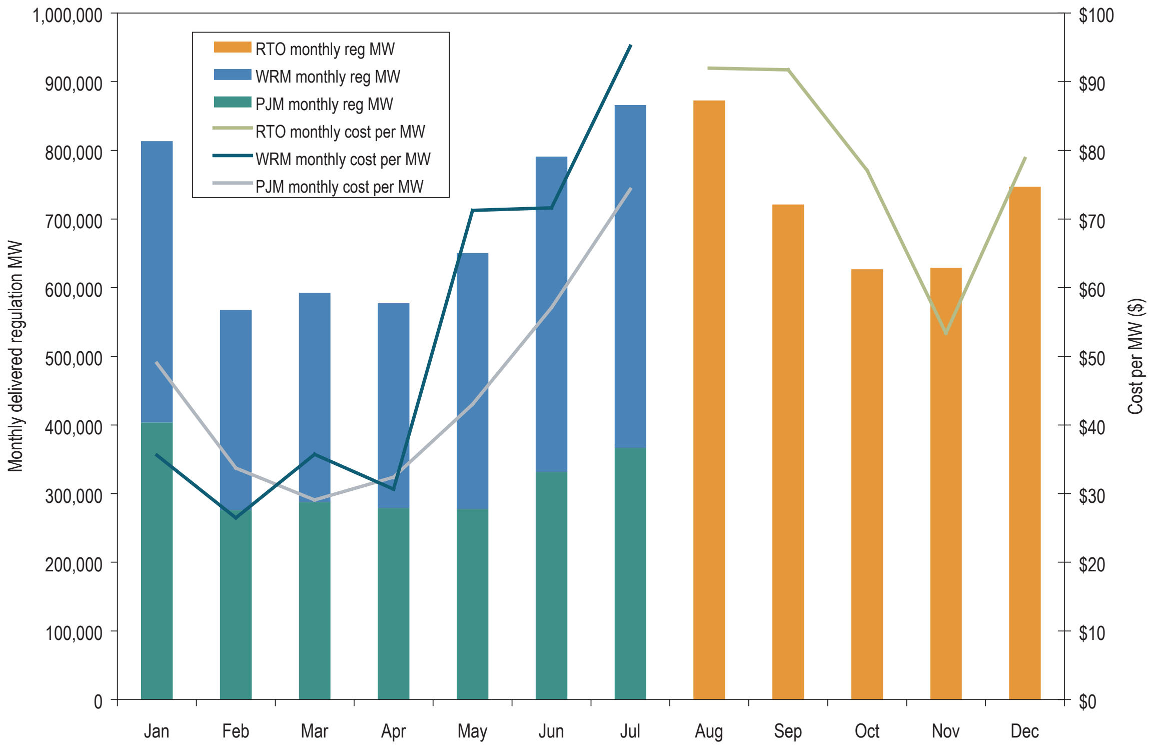
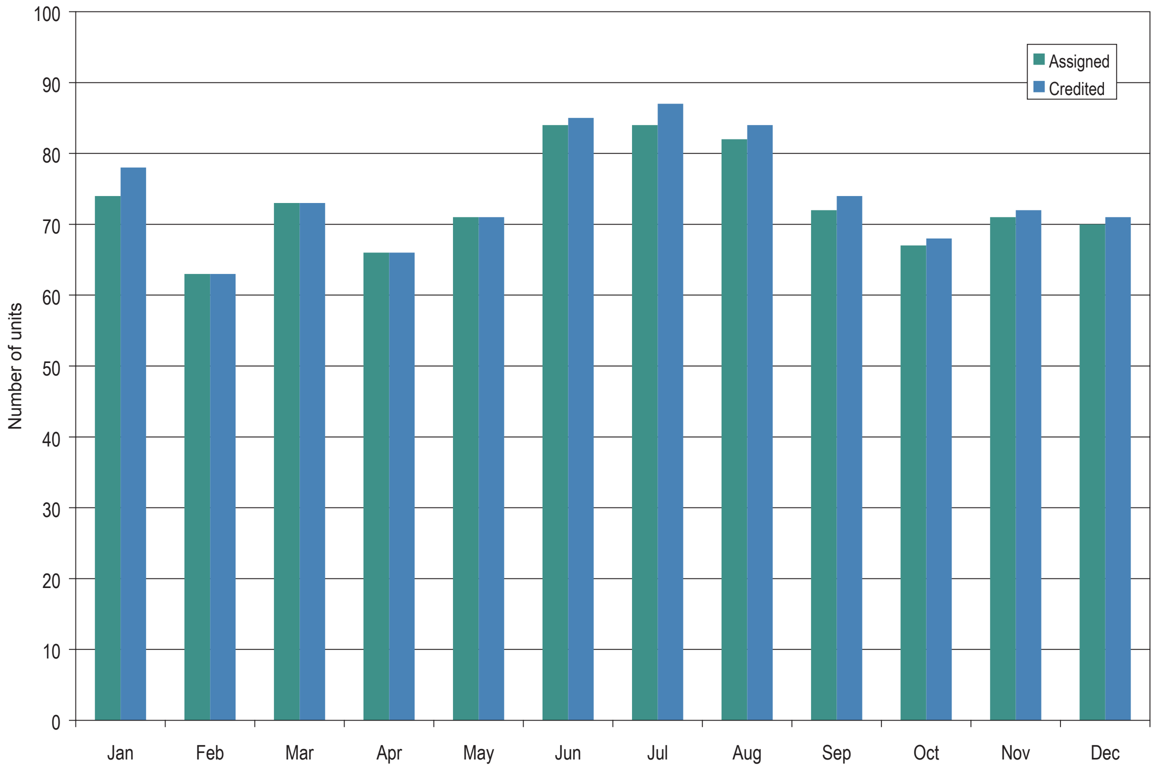


Figure 6-9 shows the average number of units per hour required to satisfy PJM's regulation requirement.

Figure 6-9 - Average hourly count of distinct units required to satisfy regulation requirement: Calendar year 2005



Units which provide regulation are paid the higher of the RMCP or their offer plus their unit-specific opportunity cost. In a perfect market all units would be compensated at RMCP times output. Sometimes, however, circumstances require that units be paid their offer plus their unit-specific opportunity cost. Examples include units that must be redispatched because of constraints, unanticipated performance problems, or changes in the real-time LMP and, therefore, opportunity cost from the value estimated at regulation market-clearing 30 minutes prior to the operating hour. For these reasons some units are paid the value of their offer plus their unit-specific lost opportunity costs when that sum is higher than the RMCP. This means that PJM's regulation cost per MWh is somewhat higher than the RMCP. Figure 6-10 and Figure 6-11 compare the regulation cost per MWh with the regulation clearing price to show the difference between the price of regulation and the total cost of regulation.

Figure 6-10 - PJM Western Region Regulation Market daily average RMCP vs. cost per MW for regulation: Phases 4 and 5-a

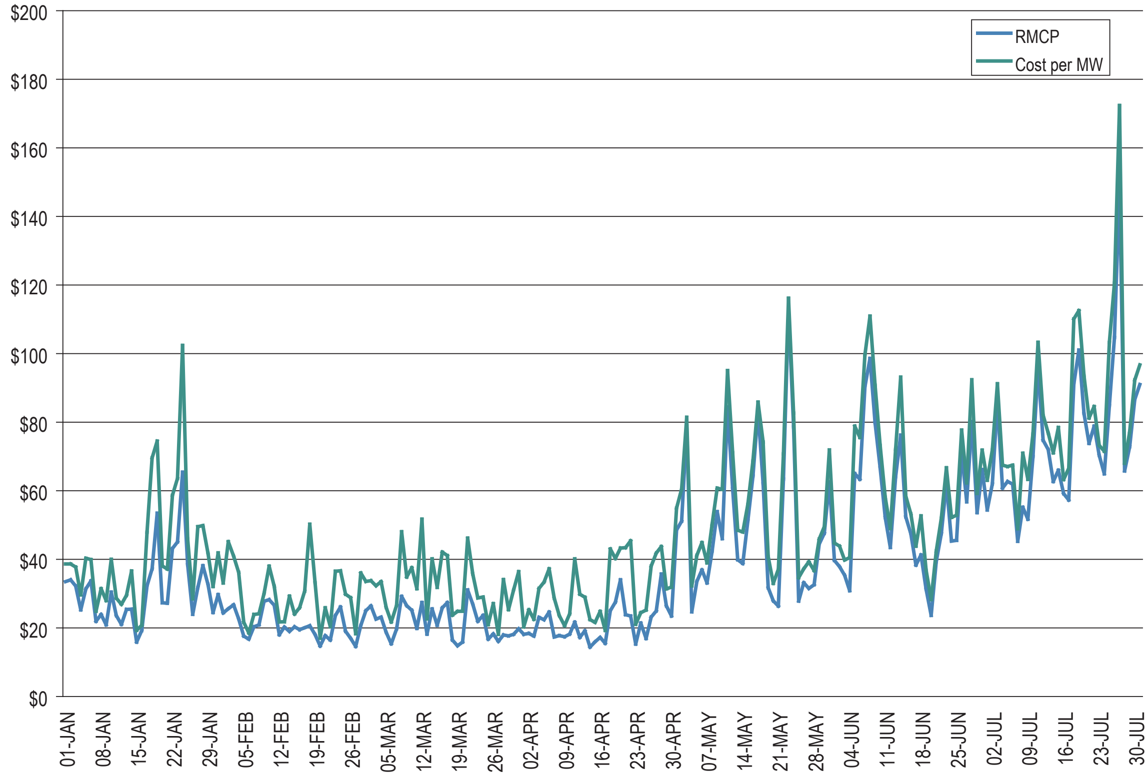
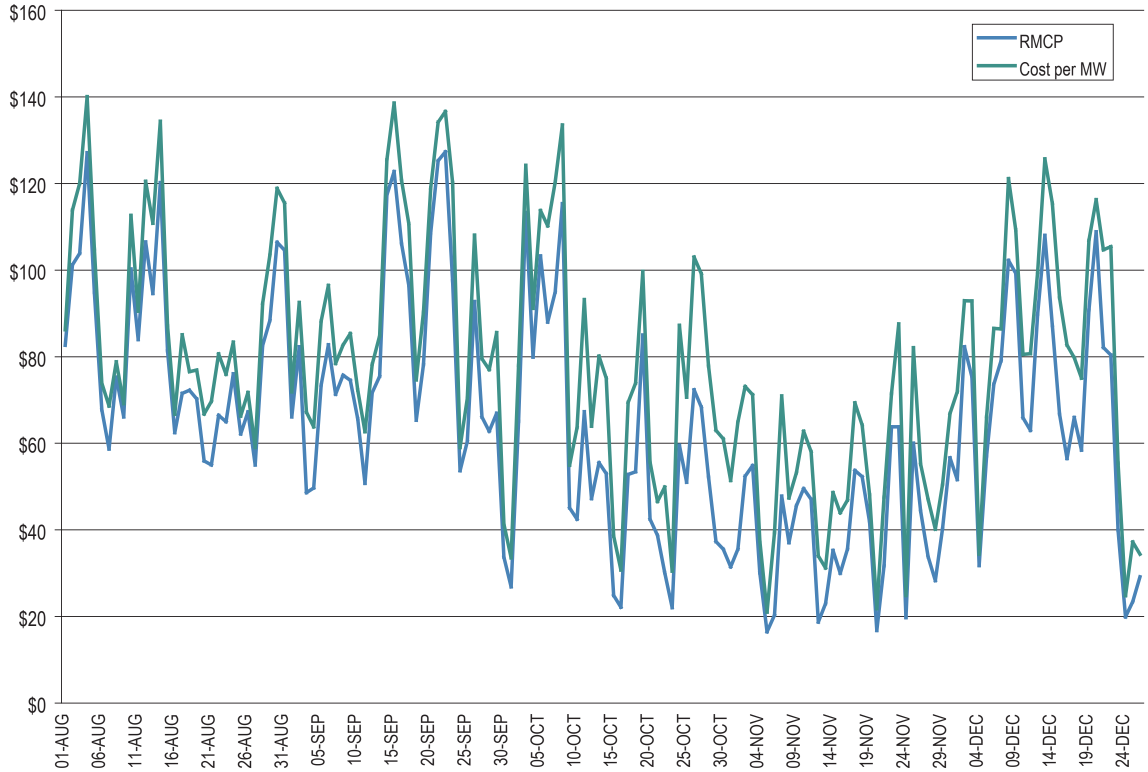


Figure 6-11 - PJM Combined Regulation Market daily average RMCP vs. cost per MW for regulation: Phase 5-b



Spinning Reserve Markets

Spinning Reserve Market Structure

The integration of Dominion on May 1, 2005, resulted in the creation of a Southern Region Spinning Reserve Market. Thus the PJM Spinning Reserve Markets include the PJM Mid-Atlantic Region Spinning Reserve Market, the Western Region Spinning Reserve Market, the ComEd Region Spinning Reserve Market and the Southern Region Spinning Reserve Market.

Demand

Tier 2 spinning requirements are determined by subtracting the amount of forecast Tier 1 spinning reserve available from each spinning control area spinning reserve requirement for the period. The total spinning reserve requirement is different for each of the four regional Spinning Reserve Markets. For the Mid-Atlantic Region, the requirement is 75 percent of the largest contingency in the region, provided that 25 percent of the largest contingency is available as nonsynchronized, 10-minute reserve. For the ComEd Region, the requirement is 50 percent of the ComEd Control Zone's load ratio share of the largest contingency in the North American Electric Reliability Council's (NERC) Mid-America Interconnected Network, Inc. (MAIN) Region. From October 1 to December 3, 2004, this was 269 MW. After December 3, 2004, the ComEd Control Zone's spinning requirement was 216 MW. For the Western Region, the requirement is 1.5 percent of the daily peak-load forecast. For the Southern Spinning Reserve Zone, the requirement is the Dominion Control Zone's load ratio share of the largest system contingency within the Virginia and Carolinas Area (VACAR), minus the available 15-minute quick start capability within the Southern Spinning Reserve Zone.

Computed in accordance with the requirements above, the average MW spinning requirement was: 1,091 MW, for the PJM Mid-Atlantic Region; 217 MW for the ComEd Spinning Zone; 437 MW for the Western Region; and 5 MW for the Southern Spinning Reserve Zone (May to December only).

Figure 6-12 - PJM Mid-Atlantic Spinning Region average hourly required spinning vs. Tier 2 spinning purchased: Calendar year 2005

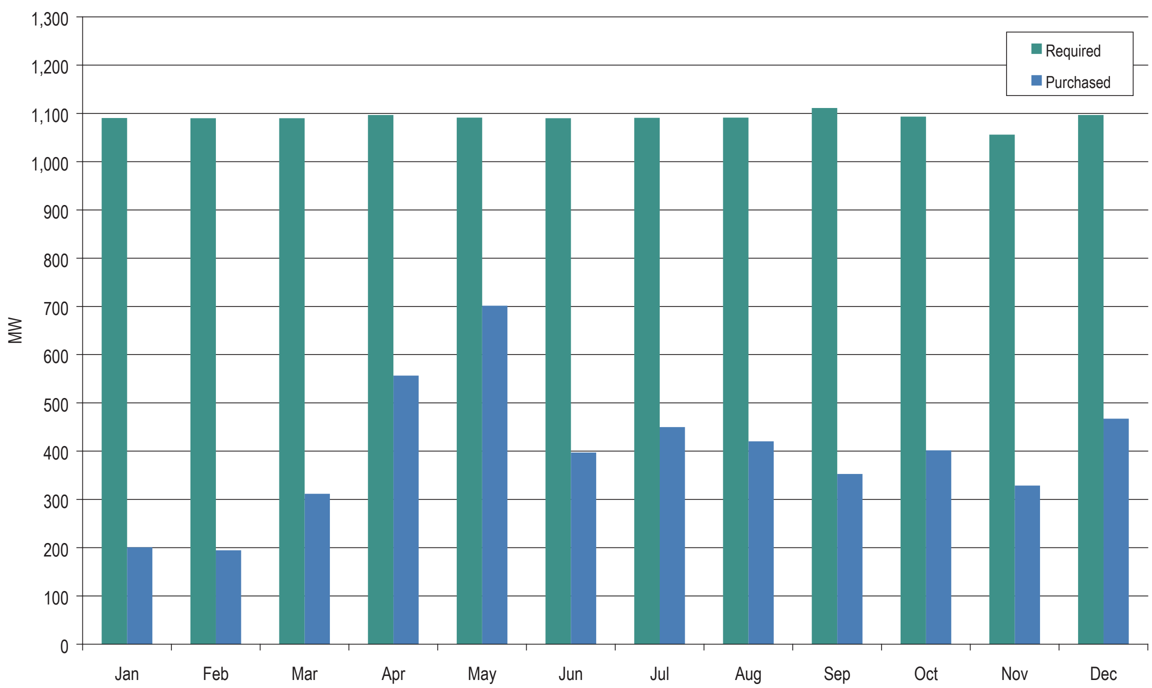


Figure 6-13 - PJM ComEd Spinning Region average hourly required spinning vs. Tier 2 spinning purchased: Calendar year 2005

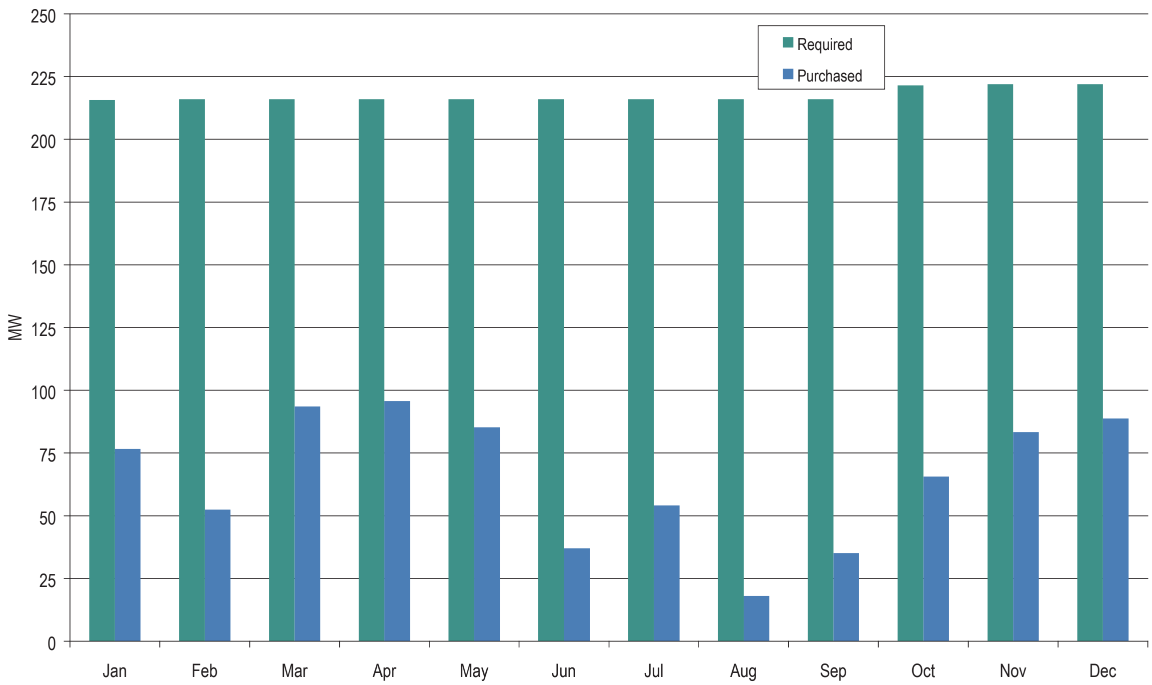
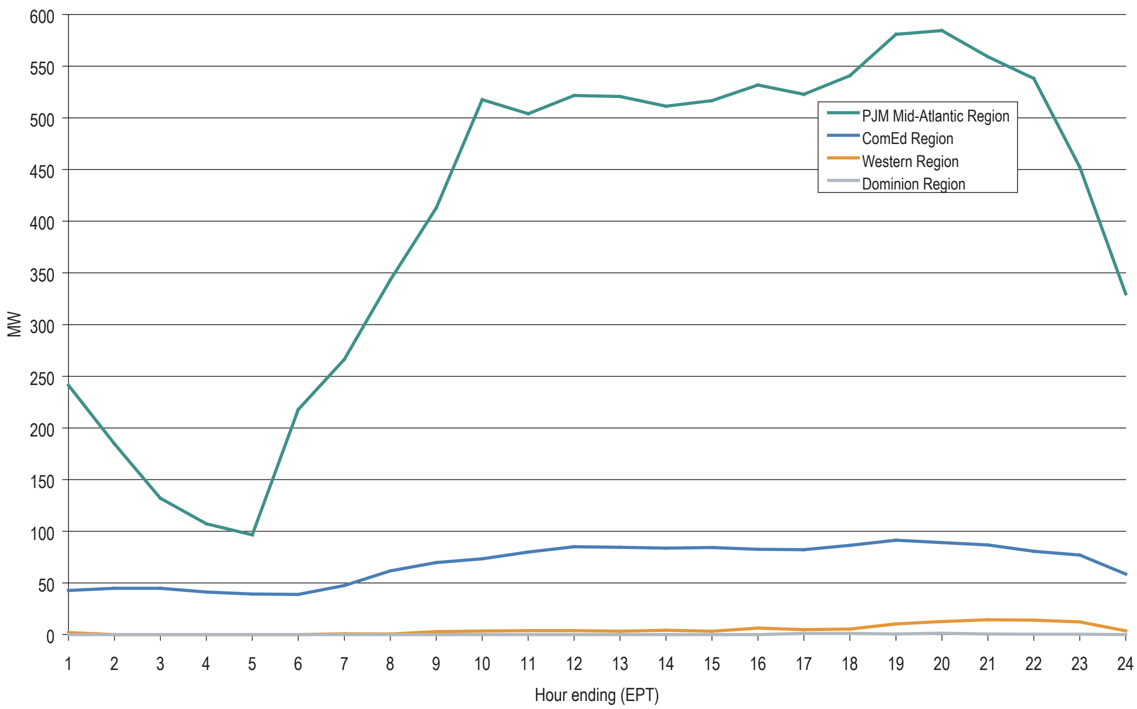


Figure 6-12 and Figure 6-13 show the average hourly spinning required and the average hourly Tier 2 spinning MW purchased during 2005 for the PJM Mid-Atlantic and ComEd Spinning Regions. Results for the Western Region Spinning Reserve Zone and the Southern Spinning Reserve Zone are not shown because Tier 2 spinning MW purchases were insignificant in those control areas during 2005. Spinning MW requirements are different for each of the four spinning regions in PJM. These differences are the result of specifications from local reliability councils, reserve-sharing arrangements with neighboring control areas and the types of generation available in the control area. The Southern Spinning Reserve Zone is a member of the VACAR subregion of NERC's Southeastern Electric Reliability Council (SERC). VACAR specifies that available 15-minute quick start reserve can be subtracted from the largest contingency to determine spinning reserve requirements. The amount of 15-minute quick start reserve available in VACAR is sufficient to make Tier 2 spinning requirements zero for most hours. Similarly, in the Western Region Spinning Reserve Zone most of the required spinning reserve is available as Tier 1 from large, frequently running baseload units, reducing its Tier 2 spinning requirement to zero in most hours. In both the PJM Mid-Atlantic and ComEd Spinning Regions the spinning reserve requirement is a function of the largest contingency. For the PJM Mid-Atlantic Region the hourly spinning requirement was usually 863 MW during off-peak hours and 1,150 MW during on-peak hours. Sometimes temporary grid conditions such as maintenance outages can cause double contingencies so there were times throughout the year when the on-peak spinning requirement was 1,380 MW. The average hourly Tier 2 spinning required for the PJM Mid-Atlantic Region was 1,091 MW. In the ComEd Region, the hourly requirement was 216 MW from January through September and 222 MW from October through December. Figure 6-12 and Figure 6-13 illustrate monthly average of the spinning reserve requirement and the amount of Tier 2 spinning actually purchased. The difference between the required spinning and Tier 2 spinning purchased is the amount of Tier 2 spinning available. Figure 6-14 illustrates the amount of Tier 2 spinning purchased by hour of the day. The hour variability reflects differing spinning reserve requirements for off-peak and on-peak hours as well as different amounts of Tier 1 spinning available.

Figure 6-14 - Average hourly Tier 2 spinning MW purchased (By hour of day): Calendar year 2005



Supply

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

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

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

Under the Spinning Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed. Tier 1 spinning payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the spinning energy premium less the hourly integrated LMP. The spinning energy premium is defined as the average of the five-minute LMPs calculated during the spinning event plus $50 per MWh.[21] All units called on to supply Tier 1 or Tier 2 spinning have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response. Tier 2 units assigned spinning by market operations are compensated whether or not they are actually called on to supply spinning so they are penalized if their MW output fails to meet their assignment.

There were significant changes to the geographic structure of PJM's Spinning Reserve Markets in 2005. In Phase 4, PJM had three Spinning Reserve Markets: the PJM Mid-Atlantic Spinning Reserve Zone, the Western Spinning Reserve Zone and the ComEd Spinning Reserve Zone. During Phase 4, the Western Spinning Reserve Zone was comprised of AP, AEP, DAY and DLCO Control Zones. In Phase 5, the Dominion Control Zone was integrated into PJM and became the Southern Spinning Reserve Zone. Dominion remained a separate Spinning Reserve Market because as a member of SERC it has distinct spinning reserve requirements and reserve-sharing agreements.

Under the Spinning Reserve Market rules, Tier 2 spinning resources are paid to be available as spinning reserve, regardless of whether the units are called upon to generate in response to a spinning event and are subject to penalties if they do not provide spinning reserve when called. The price for Tier 2 spinning resources is determined in a market for Tier 2 spinning resources. Several steps are necessary before the hourly Tier 2 Spinning Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit; 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. If spinning requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit-order price of the highest price, Tier 2 resource needed to fulfill spinning requirements, the marginal unit.[22]

The spinning offer price submitted for a unit can be no greater than the unit's operating and maintenance cost plus a $7.50 per MWh margin.[23,24] The market-clearing price is comprised of the marginal unit's spinning offer price, the cost of energy use and the unit's opportunity cost. All units cleared in the Spinning Reserve Market are paid the higher of either the market-clearing price or the unit's spinning offer plus the unit-specific LOC and/or the cost of energy use incurred.

The Mid-Atlantic Region, the Western Region, the ComEd Region and the Southern Region Spinning Reserve Zones all operate under similar business rules. The Tier 2 Spinning Reserve Market in each of PJM's spinning reserve zones is cleared on cost-based offers because the structural conditions for competition do not exist. The structural issue can be more severe when the Spinning Reserve Market becomes local because of transmission constraints.

21 See "PJM Manual 11: Scheduling Operations," Revision 26 (November 9, 2005), pp. 66-69.

22 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price is established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.

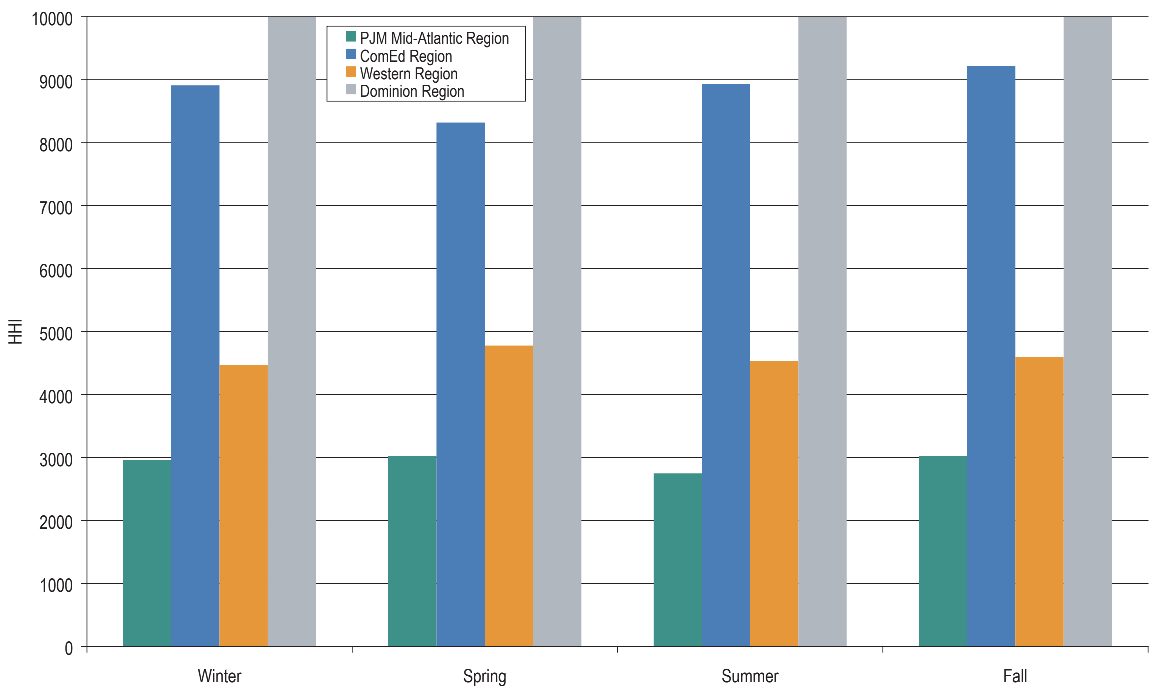
23 See "PJM Manual 11: Scheduling Operations," Revision 26 (November 9, 2005), p. 59.

24 See "PJM Manual 15: Cost Development Guidelines," Revision 6 (March 2, 2006), p. 35.

Concentration of Ownership

The offered and eligible Tier 2 Spinning Reserve Markets for all four geographic markets are highly concentrated. (See Figure 6-15.) During calendar year 2005, in the Mid-Atlantic Region average HHI for offered Tier 2 spinning was 2167 and 2940 for eligible spinning. In the ComEd Region during 2005 the average HHI for offered spinning was 6305 and 8844 for eligible spinning. In the Western Region the average HHI for offered spinning was 4173 and 4593 for eligible spinning. In the Southern Region the HHI was 10000.

Figure 6-15 - Eligible Spinning Reserve Market HHI: Calendar year 2005



Spinning Reserve Market Performance

Spinning Reserve Offers

Figure 6-16 shows the daily average hourly offered Tier 2 spinning. Figure 6-17 shows the daily average hourly eligible Tier 2 spinning. Daily Tier 2 spinning offers are fairly stable reflecting the Tier 2 spinning capability of the units, other unit attributes and economic decisions by sellers. The level of eligible spinning displays considerable variability because it is calculated hourly and reflects current market and grid conditions, including LMP, unit dispatch and system constraints.

Figure 6-16 - Tier 2 spinning offered MW: Calendar year 2005

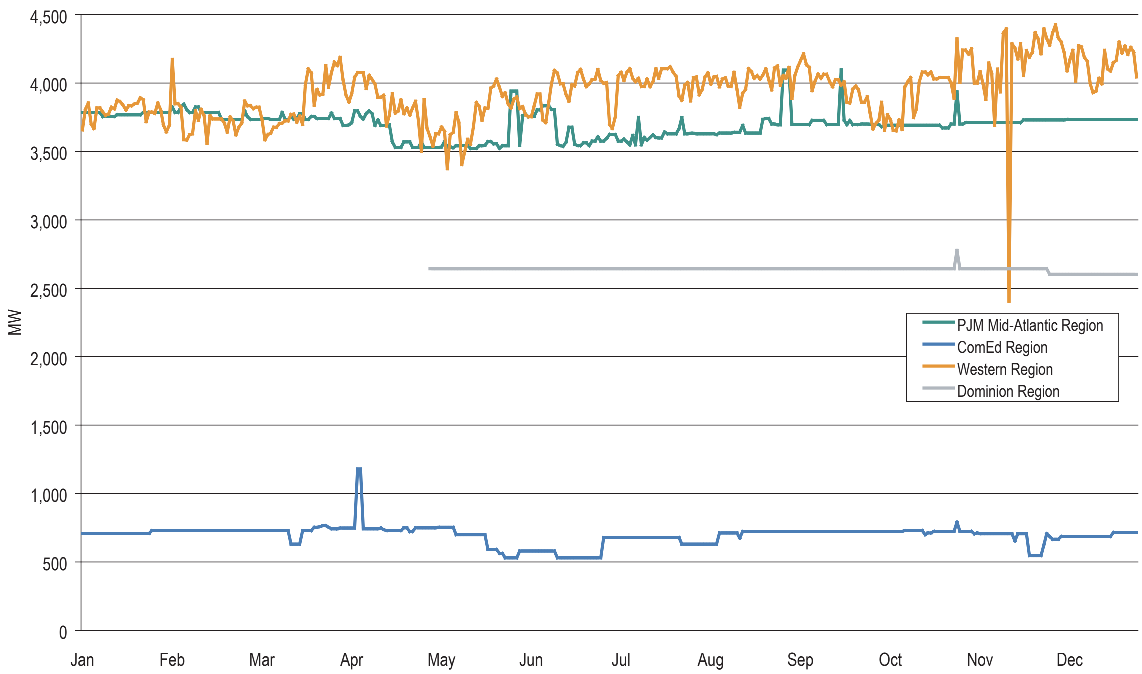


Figure 6-17 - Tier 2 spinning eligible MW: Calendar year 2005

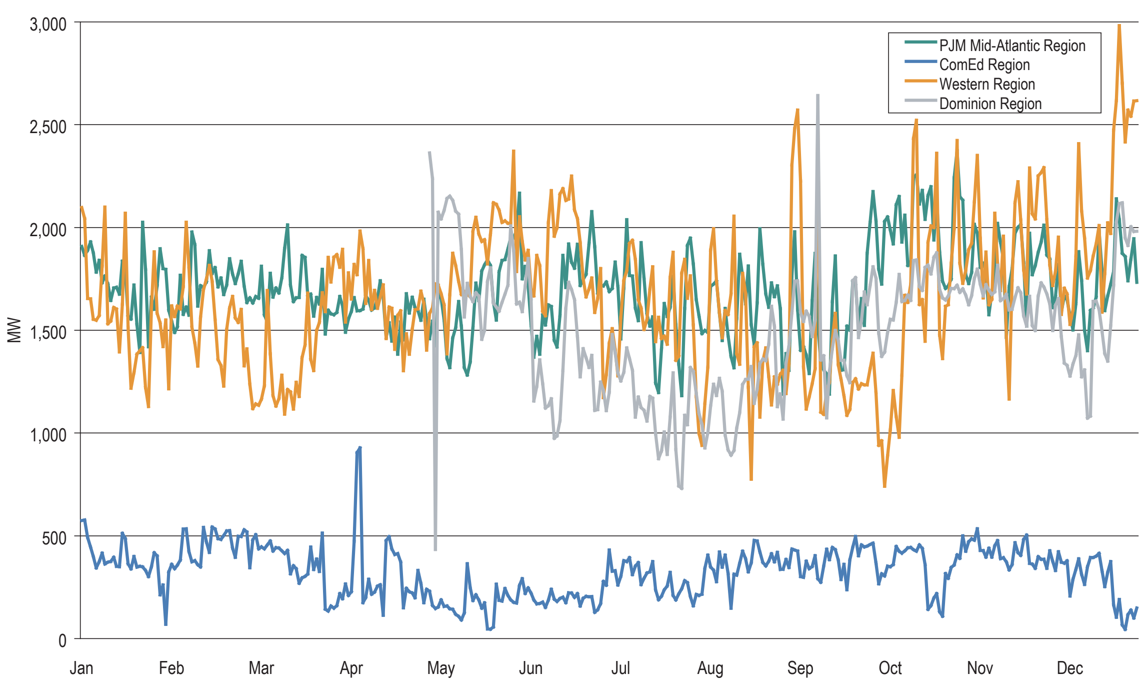
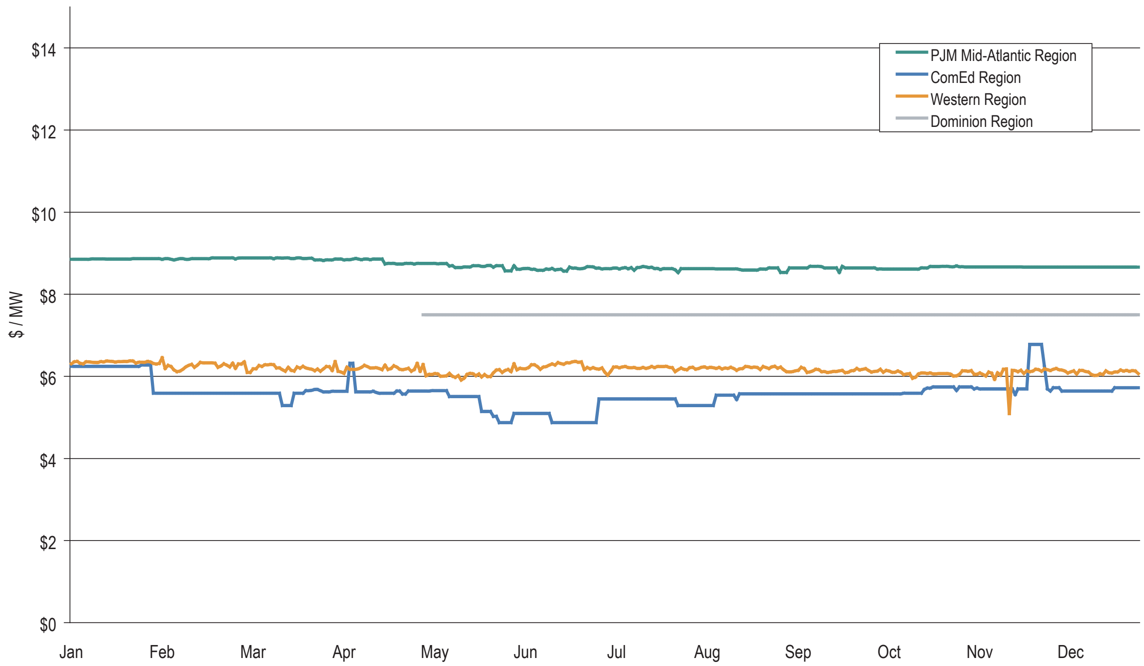


Figure 6-18 shows average offer price per MW by ancillary service area. Tier 2 spinning offers are capped at $7.50 plus costs. The clearing price for Tier 2 spinning includes lost opportunity costs based on LMP, energy use, and operating costs for units which are actually assigned Tier 2 spinning. (See Figure 6-19.)

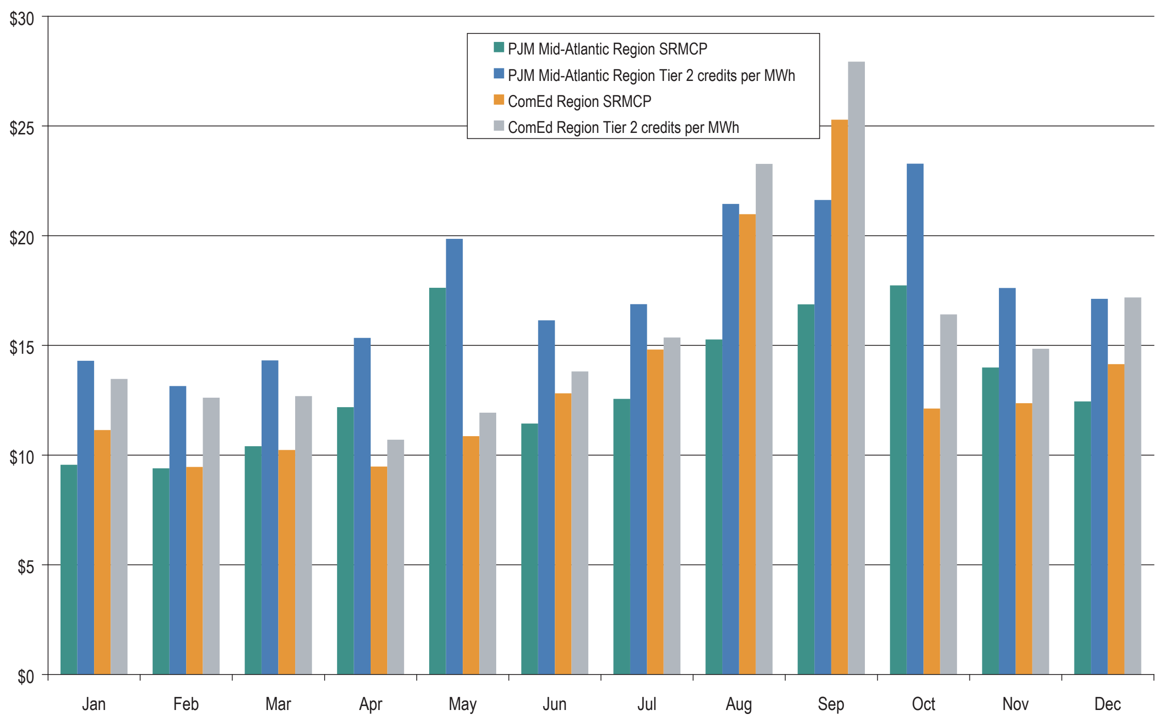
Figure 6-18 - Tier 2 spinning average offer price per MW: Calendar year 2005



Spinning Reserve Prices

Figure 6-19 shows the average spinning reserve market-clearing price (SRMCP) and the cost per MW associated with meeting PJM demand for spinning reserve. The average PJM Mid-Atlantic Region SRMCP rose in 2005 to $13.29. The cost per MW of meeting the spinning reserve requirements also rose to approximately $17.59 per MWh. In the ComEd Region, the average SRMCP was $13.64 and the cost per MW for meeting the spinning reserve requirement was $15.85. No price data are presented for the Western Region Spinning Reserve Market because there was almost always adequate Tier 1 spinning reserve to meet the requirements for spinning reserve without clearing the Tier 2 market.

Figure 6-19 - Tier 2 spinning market-clearing price and cost per MW: Calendar year 2005



The Western Region Spinning Reserve Market (not shown in Figure 6-19) during 2005 almost never had a clearing price because available Tier 1 spinning was always sufficient to cover the spinning requirement. For the 311 hours between June and December when a Spinning Reserve Market was cleared in the Western Region, the average clearing price was $12.27 and the cost of spinning was $66.75 per MWh. The Southern Region (not shown in Figure 6-19) was cleared only 18 hours between June 1 and December 31 with an average SRMCP of $11.34 and an average cost per MWh for Tier 2 spinning of $35.10.

Like Regulation Market prices, Tier 2 spinning reserve prices are more reflective of costs associated with the marginal unit than they are of offer prices. Unlike regulation, however, the costs in Tier 2 spinning are more than just opportunity costs; they are also energy costs for condensing MWh (which must be purchased from the Real-Time Energy Market when the unit is spinning), and startup costs if the assigned unit is not already running. Figure 6-20 and Figure 6-21 show the relationship between the marginal unit's offer price and the SRMCP. For the PJM Mid-Atlantic Region during all of 2005 the Tier 2 spinning offer price averaged 67 percent of the SRMCP.

Figure 6-20 - PJM Mid-Atlantic Region Tier 2 spinning reserve clearing prices and marginal unit offer price: Calendar year 2005

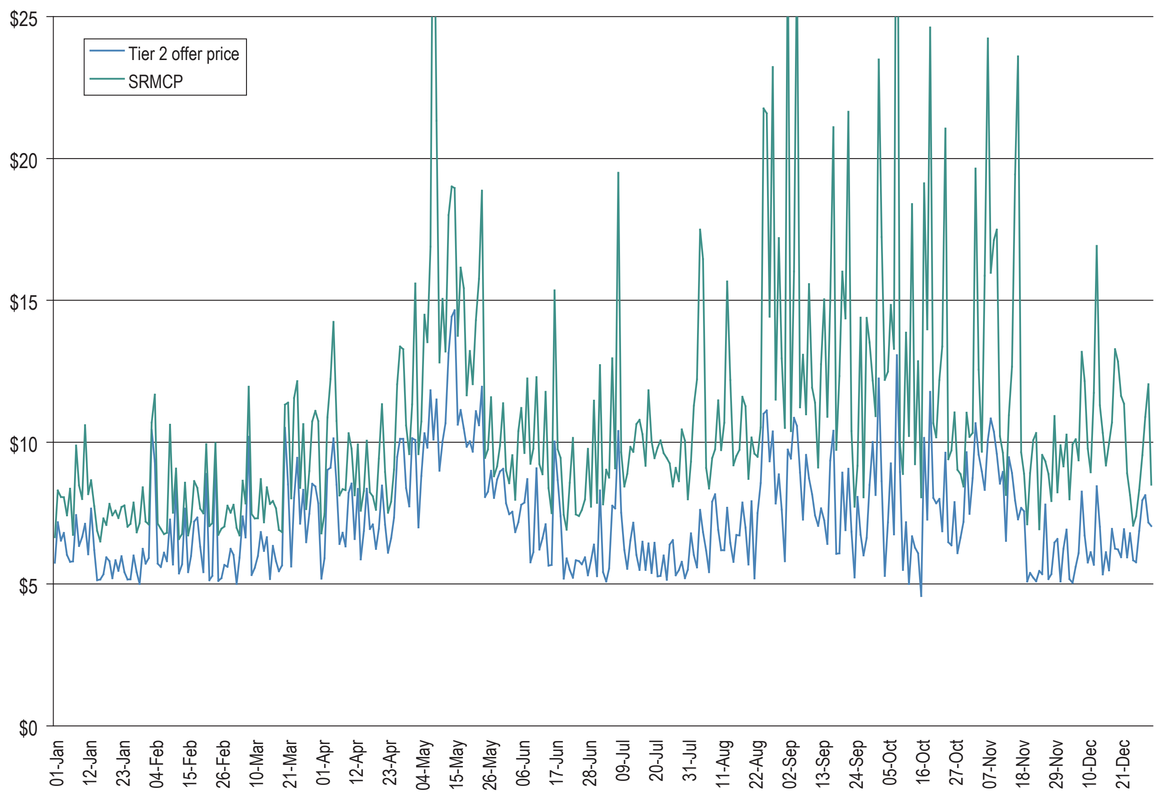


Figure 6-21 shows the relationship between the marginal units' offer price and the SRMCP for the ComEd Region. For the ComEd Region during all of 2005, the Tier 2 spinning offer price averaged 51 percent of the SRMCP.

Figure 6-21 - PJM ComEd Tier 2 spinning reserve clearing prices and marginal unit offer price: Calendar year 2005

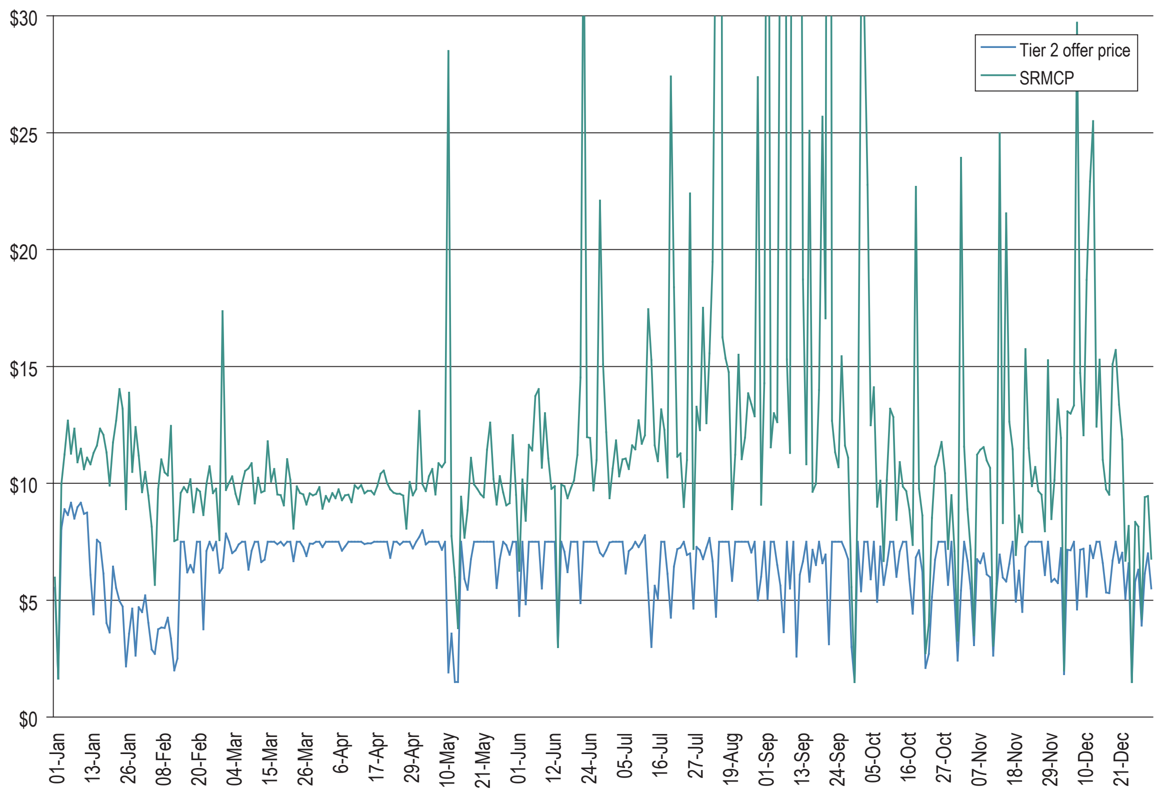
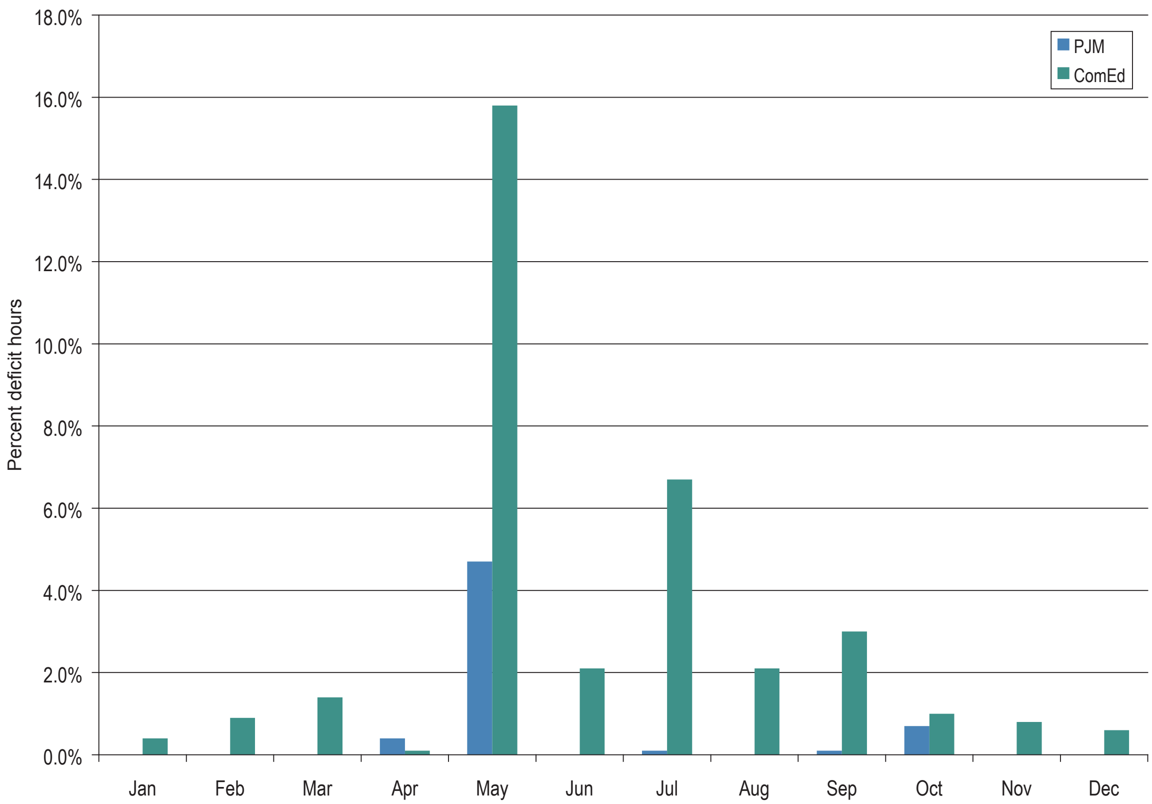


Figure 6-21 shows the level of Tier 1 and Tier 2 spinning reserve purchased from suppliers during calendar year 2005. Tier 1 resources are paid only if they respond during spinning events while Tier 2 resources are paid for providing hourly reserve. In general, more Tier 2 resources are purchased than Tier 1 resources, and Tier 2 payments are higher than Tier 1 payments. An important exception to this general rule was in the Western Region Spinning Reserve Market where a large baseload of available operating reserves ensures that Tier 1 spinning reserve services were almost always sufficient to cover the spinning requirement so Tier 2 spinning reserve was rarely purchased.

Spinning Reserve Availability

A spinning reserve deficit occurs when the combination of Tier 1 and Tier 2 spinning is not adequate to meet the spinning reserve requirement. Except for a brief period in the ComEd Region during May (See Figure 6-22.), none of PJM's Spinning Reserve Markets had significant spinning reserve deficits during 2005.

Figure 6-22 - Tier 2 Spinning Reserve Market deficits: Calendar year 2005



The Tier 2 spinning deficit peak during May in the ComEd Region was caused indirectly by a need for regulation and the assignment of several CTs, which otherwise provided spinning reserve to regulation. None of these Tier 2 spinning deficits created a serious problem because the ComEd Region's reserve requirement was satisfied by a reserve-sharing agreement with other members of MAIN.