SECTION 3 - INTERCHANGE TRANSACTIONS

The integration of several service territories into the PJM regional transmission organization (RTO) during 2004 resulted in significant changes to its external interfaces. These interfaces are the seams between PJM and other regions. PJM market participants import energy from, and export energy to, external regions on a continuous basis. Such transactions may fulfill long-term or short-term bilateral contracts or take advantage of price differentials.

In the *2004 State of the Market Report*, the calendar year is divided into three phases, corresponding to market integration dates.

- **Phase 1.** The four-month period from January 1 through April 30, 2004, when PJM was comprised of 12 zones.[1,2] Eleven of these [i.e., 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)] comprised the Mid-Atlantic Region. The remaining zone, the Allegheny Power Company Control Zone (AP), comprised the PJM Western Region.

- **Phase 2.** 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).[3]

- **Phase 3.** 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.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports**

  Phase 1. During the four months ended April 30, 2004, PJM was a net importer of power, averaging 1.8 million MWh of net interchange[4] (positive value indicates import, negative value indicates export) per month, or 0.9 million MWh more per month than for the same period in 2003. The 2004 period's average monthly gross import volume of 3.0 million MWh also

1 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The 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 the 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.
2 Control areas external to PJM are referred to as control areas not control zones. For example, the FirstEnergy control area is not referred to as the FirstEnergy control zone.
3 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).
4 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to positive net imports and negative net interchange is equivalent to positive net exports.

represented an increase from the 2.6 million MWh experienced in 2003. Gross exports decreased by 600,000 MWh per month in 2004 compared to 2003, averaging 1.1 million MWh in 2004 versus 1.7 million MWh in 2003.

Phase 2. During the five months ended September 30, 2004, PJM, including the ComEd Control Area, became a net exporter of power. Monthly average net interchange was -1.1 million MWh. Gross monthly import volumes averaged 2.8 million MWh while gross monthly exports averaged 3.9 million MWh.

Phase 3. During the three months ended December 31, 2004, PJM, including the AEP and DAY Control Zones, continued to be a net exporter of power. Monthly average net interchange was -1.3 million MWh. Gross monthly import volumes averaged 4.3 million MWh while gross monthly exports averaged 5.6 million MWh.

- **Interface Imports and Exports**[5]

Phase 1. During Phase 1, net imports at two interfaces accounted for 94 percent of total net imports. Net imports at PJM's interface with the AEP control area (PJM/AEP) were 44 percent and at its interface with the FirstEnergy control area (PJM/FE) were 50 percent of total net imports. Net exports occurred only at the PJM interface with the New York Independent System Operator (PJM/NYIS). Five interfaces were active during Phase 1.

Phase 2. During Phase 2, PJM became a net exporter of energy. PJM's largest exporting interface was AEP Northern Illinois (PJM/AEPNI); it carried 44 percent of the net export volume. Nine other interfaces were net exporters. The largest net importing interface was PJM/FE which carried 49 percent of the net import volume while PJM/AEPPJM carried 38 percent. The number of interfaces in Phase 2 rose to 14.

Phase 3. During Phase 3, PJM continued to be a net exporter of energy. The two largest net exporting interfaces totaled 43 percent of the total net exporting volume: PJM/NYIS at 22 percent and PJM/Michigan Electric Coordinated System (PJM/MECS) with 21 percent. Ninety-two percent of the net import volume was carried on three interfaces: PJM/Illinois Power (PJM/IP) carried 33 percent, PJM/Ohio Valley Electric Corporation (OVEC) carried 30 percent and PJM/FE carried 29 percent of the volume. The number of interfaces increased to 22 during Phase 3.

- **Modified Interfaces and Pricing Points**

New Interfaces. Integration of the ComEd Control Area into PJM on May 1, 2004, introduced new interfaces. The number of external interfaces increased from five to 14. The subsequent integration of the AEP and DAY Control Zones on October 1, 2004, significantly enlarged the boundaries of PJM and the number of interfaces grew from 14 to 22.

New Pricing Points. During Phase 2, integration of the ComEd Control Area, with its accompanying interfaces, required new pricing points. The physical configuration and the potential for power schedules, but not physical power flows, to bypass a control area required

5 Interfaces are named after adjacent control areas. As is true of the control areas themselves, this naming convention does not imply anything about any company operating within the control areas.

pricing points that recognized the location of generation and the path of power flows. The result was that PJM increased the number of pricing points from six in Phase 1, to 23 in Phase 2. The subsequent integration of the AEP and DAY Control Zones in Phase 3 reduced the potential for loop flows and simplified the pricing point issue. The number of pricing points was reduced to nine. The issue of potential control zone bypass was virtually eliminated with the result that fewer pricing points are now needed to account for transactions with neighboring control areas and the generators located there or in external, non-contiguous control areas.[6]

Interchange Transaction Issues

- **Fewer PJM TLRs.** The number of transmission loading relief procedures (TLRs) issued by PJM declined after the integration of the AEP and DAY Control Zones. The integration meant that PJM could redispatch generating units to relieve constraints on facilities in the newly integrated areas where PJM had previously relied on TLRs for constraint control. The result was a drop in the number of TLRs called by PJM, particularly in the AEP Control Zone.

- **Midwest ISO.** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (JOA)[7] provides for relief of constraints on certain coordinated flowgates. PJM redispatches generation to aid in providing this relief.

- **Actual Versus Scheduled Power Flows.** Loop flow is one reason that actual and scheduled flows may not match at a particular interface. Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths that the energy takes. Even when energy is scheduled on a path consistent with its expected actual flow, other loop flows can cause some of the energy to flow on another path. Outside of PJM's LMP-based Energy Market, energy is scheduled and paid for based on contract path despite the fact that the associated actual energy deliveries flow on the path of least resistance. For example, loop flow can result when a transaction is scheduled between two external control areas and some, or all, of the actual flows occur at PJM interfaces. Loop flow can also result when transactions are scheduled into or out of PJM on one interface, but actually flow on another. Although PJM's total scheduled and actual flows were approximately equal in 2004, they were often not equal for each individual interface. PJM's method of defining pricing points is designed to provide price signals consistent with the actual power flows and thus to minimize the incentive to create loop flow.

- **Transactions and PJM Area Control Error (ACE).** An important function performed by PJM is to balance load and generation on a continuous basis. ACE is the metric used to measure that balance. One component in the measurement of ACE is the flow into and out of PJM that results from external transactions. The other component is frequency error. When ACE deviates significantly from zero in either direction, certain measures are used to correct it. Regulation is the primary tool dispatchers use to control ACE.[8]

- **PJM and New York Transaction Issues.** During 2004, the relationship between prices at the PJM/NYIS interface and at the New York Independent System Operator (NYISO) PJM proxy

6 See Appendix D, "Interchange Transactions" for a more detailed discussion of interface pricing issues.
7 See Joint Operating Agreement (JOA) between the Midwest ISO and PJM (December 30, 2003) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (906 KB).
8 See Appendix F, "Ancillary Service Markets."

bus appeared to reflect economic fundamentals. The relationship between interface price differentials and power flows between PJM and the NYISO also continued to appear to reflect economic fundamentals. As in 2003, however, both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

Interchange Transaction Activity

Aggregate Imports and Exports (by Phase)

New control zones were integrated into PJM in 2004 and these integrations affected the PJM balance of imports and exports. Historically, PJM had been a net importer of power and that continued to be the case during the first phase of 2004. With the integration of the ComEd Control Area and the AEP and DAY Control Zones, PJM became a net exporter of power. (See Figure 3-1.)

Phase 1

During the four-month period ended April 30, 2004, PJM was a net importer of energy for each month. Net interchange of 7.4 million MWh during 2004 exceeded net interchange of 3.7 million MWh for the comparable 2003 period. This increase was the result of both an increase in gross imports (11.8 from 10.4 million MWh for the 2004 and 2003 periods, respectively) and a decrease in gross exports (4.5 from 6.8 million MWh for the 2004 and 2003 periods, respectively). For the periods under comparison, the peak months for net interchange were January in 2004 (2.3 million MWh) and March in 2003 (1.5 million MWh).

Phase 2

During the five-month period ended September 30, 2004, PJM became, for the first time, a net exporter of energy in each month as net exports from ComEd outweighed net imports of the preintegration PJM. Monthly exports averaged 3.9 million MWh and monthly imports averaged 2.8 million MWh for an average monthly net interchange of -1.1 million MWh.

Phase 3

During the three-month period ended December 31, 2004, PJM continued to be a net exporter of power. Monthly exports averaged 5.6 million MWh and monthly imports averaged 4.3 million MWh for an average monthly net interchange of -1.3 MWh.

2004 Trends

While PJM market participants have generally imported and exported energy primarily in the Real-Time Energy Market, that pattern appears to be changing. (See Figure 3-1.) Day-ahead volume continues to be relatively small by comparison. (See Figure 3-2.) In 2004, transactions in the Day-Ahead Energy Market were 27 percent of the gross import volume (18 percent in 2003) in the Real-Time Market while transactions in the Day-Ahead Market were 39 percent of the gross export volume (16 percent in 2003) in the Real-Time Market. The increased level of transactions in the

Day-Ahead Market compared to the level of transactions in the Real-Time Market was even more evident in Phase 3. Transactions in the Day-Ahead Market were 35 percent of the gross import volume in the Real-Time Market while transactions in the Day-Ahead Market were 53 percent of the gross export volume in the Real-Time Market in Phase 3.

Figure 3-1 - PJM real-time imports and exports: Calendar year 2004

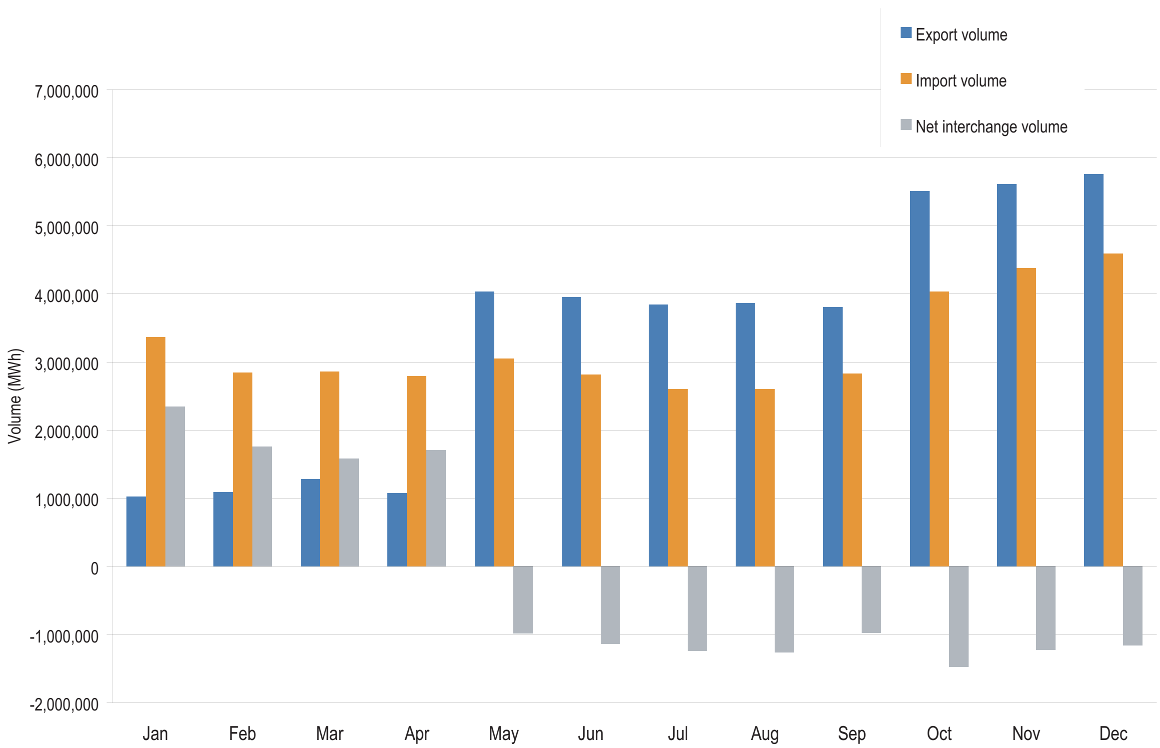


Figure 3-2 - Total day-ahead import and export volume: Calendar year 2004

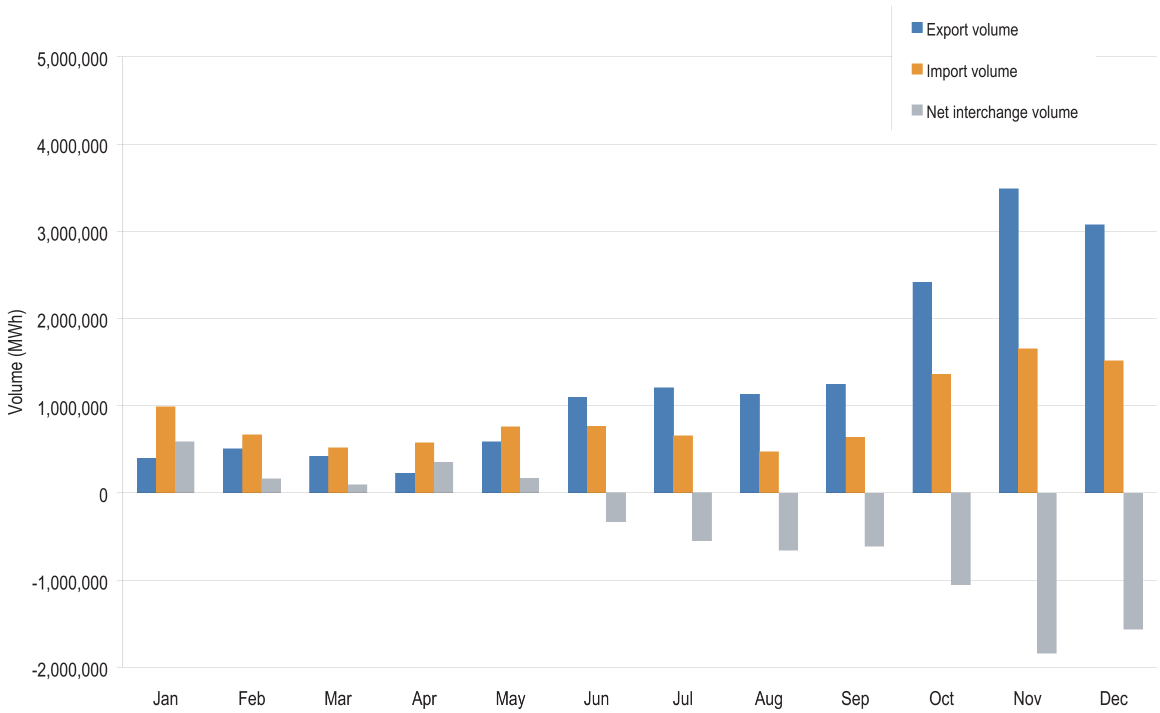
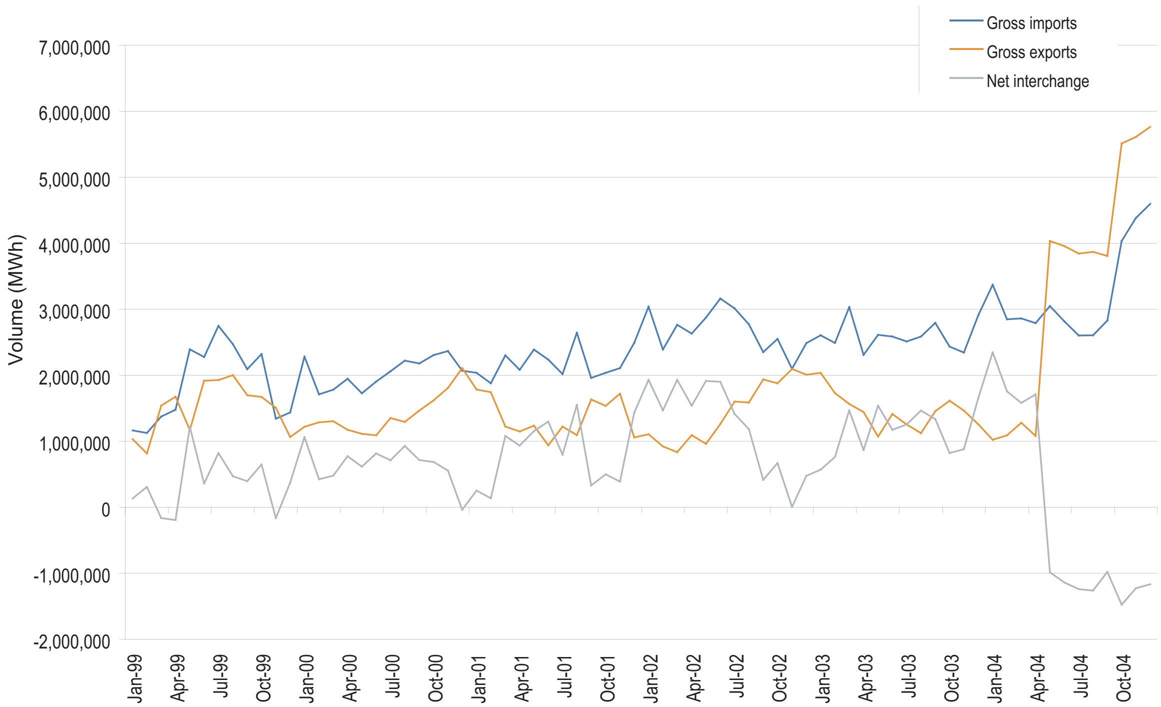


Figure 3-3 shows import and export volume for PJM from 1999 through 2004. Gross exports exhibited a particularly sharp increase in Phase 2 that was not matched by imports while the increase in gross exports and imports in Phase 3 was more balanced.

Figure 3-3 - PJM import and export transaction volume history: Calendar years 1999 to 2004



Interface Imports and Exports (by Phase)

Total imports and exports are comprised of flows at each PJM interface. Net interchange is shown by interface for each phase of 2004 in Table 3-1 while gross imports and exports are shown by interface for each phase of 2004 in Table 3-2 and Table 3-3.

Phase 1

During Phase 1, when PJM encompassed the Mid-Atlantic Region and the AP Control Zone, net interchange was relatively stable with a standard deviation of 0.3 million MWh on a monthly net interchange average of 1.8 million MWh. PJM/FE and PJM/AEP together accounted for 94 percent of the net imports (50 and 44 percent, respectively). As had previously been the case, PJM/NYIS was the lone net exporting interface.

The highest levels of gross imports occurred on the PJM/FE interface (47 percent) and on the PJM/AEP interface (39 percent). The PJM/ Duquesne Light Company (PJM/DLCO), PJM/Dominion Virginia Power (PJM/VAP) and PJM/NYIS interfaces had the lowest gross import volumes, with 4 percent, 4 percent and 5 percent, respectively. Approximately 82 percent of the gross exports occurred at the PJM/NYIS interface while PJM/AEP, PJM/VAP, PJM/FE and PJM/DLCO carried 2 percent, 3 percent, 9 percent and 4 percent, respectively.

Phase 2

With the addition of the ComEd Control Area to PJM, the number of external interfaces increased from five to 14. Ten of these interfaces were net exporters of PJM power. The largest of them was PJM/AEPNI with 44 percent of net export volume, followed by PJM/MidAmerican Energy Company (PJM/MEC) with 18 percent and PJM/NYIS with 11 percent. PJM/Alliant Energy Corporation east (PJM/ALTE), the PJM/Alliant Energy Corporation west (PJM/ALTW), PJM/Ameren Corporation (PJM/AMRN), PJM/Central Illinois Light Company (PJM/CILC), PJM/ Northern Indiana Public Service Company (PJM/NIPS), PJM/VAP and PJM/Wisconsin Energy Corporation (PJM/WEC) made up the remaining net exporting interfaces. Four of PJM's Phase 2 interfaces were net importers of power. The largest was PJM/FE with 49 percent of total net imports, followed by PJM/AEPPJM with 38 percent. PJM/IP and PJM/DLCO were the other two importers.

The highest levels of gross imports during this period occurred on the PJM/FE interface (38 percent) and the PJM/AEPPJM interface (28 percent). The PJM/IP and PJM/NYIS each had sizable gross import volume at 10 percent and 14 percent, respectively. The remaining 10 interfaces accounted for 10 percent of gross import volume. Approximately 35 percent of gross exports occurred at the PJM/AEPNI interface. PJM/NYIS had the second highest Phase 2 gross export volume with 19 percent. The PJM/MEC interface was the next highest at 14 percent. The other 11 interfaces carried the remaining 32 percent of gross export volume.

Phase 3

With the addition of the AEP and DAY Control Zones, external interfaces increased in number from 14 to 22. Twelve of these interfaces were net exporters of PJM power. The two largest net exporting interfaces totaled 43 percent of the total net exporting volume. They were PJM/NYIS at 22 percent and PJM/MECS with 21 percent. PJM/DLCO, PJM/VAP, PJM/ALTE, PJM/ALTW, PJM/MEC, PJM/WEC, PJM/ Carolina Power & Light Company east (CPLE), PJM/ Carolina Power & Light Company west (CPLW), PJM/ Duke Energy Corp. (DUK) and PJM/Tennessee Valley Authority (TVA) made up the remaining net exporting interfaces.

Ten of PJM's Phase 3 interfaces were net importers of power. Ninety-two percent of the net import volume was carried on three of these interfaces. PJM/IP carried 33 percent, PJM/OVEC carried 30 percent and PJM/FE carried 29 percent of the volume. The other seven interfaces made up the remaining 8 percent of net import volume.

Approximately two-thirds of the gross import volume occurred on three interfaces. PJM/FE had the highest share at 26 percent. PJM/IP and PJM/OVEC carried 21 and 19 percent, respectively. The other 19 interfaces made up the remaining third of gross import volume. The distribution of gross export volume over the interfaces is more diverse than that of gross imports. The highest two gross exporting interfaces made up slightly more than a third (35 percent) of the total gross exporting volume. PJM/NYIS was the highest at 20 percent followed by PJM/MECS at 15 percent. The other 20 interfaces made up the remaining 65 percent of gross export volume.

Table 3-1 - Net interchange volume by interface (MWh x 1,000): Calendar year 2004

Interface	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEP	1,586.1	1,083.7	966.1	935.5								
DLCO	77.2	71.6	83.0	71.9	-86.0	4.6	68.4	103.0	77.6	-5.0	-19.6	-75.4
FE	1,208.6	1,222.3	1,400.6	1,358.0	1,360.4	994.7	730.9	708.2	831.6	598.4	852.7	862.3
NYIS	-681.0	-731.4	-947.1	-700.2	-193.8	-462.1	-244.8	-300.1	-525.5	-1,144.2	-919.2	-566.0
VAP	148.8	102.6	72.4	40.6	-73.4	-98.9	-98.0	-54.5	-27.9	-446.3	-555.4	-476.0
AEPNI					-1,291.3	-1,231.2	-1,308.8	-1,302.5	-1,415.0			
AEPPJM					528.7	673.1	701.8	726.7	912.9			
ALTE					-115.0	-100.9	-93.4	-100.2	-98.4	-102.1	-100.7	-108.7
ALTW					-257.4	-137.4	-162.5	-143.8	-150.4	-167.3	-164.7	-196.8
AMRN					-29.9	-108.6	-84.7	-119.5	9.2	-62.3	155.6	-45.6
CILC					4.6	-11.7	6.6	-4.0	3.8	3.5	6.9	7.4
IP					193.8	169.9	129.8	237.5	309.2	813.9	924.3	886.7
MEC					-525.7	-524.1	-596.2	-590.1	-420.6	-555.6	-393.3	-576.5
NIPS					-89.4	-2.6	-29.4	-262.5	-152.3	47.0	52.0	34.0
WEC					-417.9	-310.1	-268.4	-168.5	-337.3	-256.8	-279.7	-354.5
MECS										-796.1	-823.5	-904.7
CPLE										-258.2	-261.9	-215.9
CPLW										-73.1	-69.3	-72.1
CIN										474.9	-289.6	24.3
DUK										-315.8	-130.7	-236.6
EKPC										30.3	8.6	-4.9
IPL										20.0	19.4	13.4
LGEE										78.2	60.4	52.4
OVEC										829.0	743.2	854.4
TVA										-187.4	-44.9	-66.5

Table 3-2 - Gross import volume by interface (MWh x 1,000): Calendar year 2004

Interface	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEP	1,599.3	1,105.7	982.8	957.5								
DLCO	127.4	139.9	126.1	106.4	89.5	109.2	135.6	158.5	112.6	118.5	120.6	132.1
FE	1,285.9	1,325.4	1,513.6	1,458.5	1,504.6	1,131.5	858.0	826.0	934.8	921.7	1,195.1	1,235.5
NYIS	184.5	143.9	138.8	154.6	368.3	382.7	451.7	414.6	275.6	139.0	215.2	255.1
VAP	164.9	124.5	94.3	107.8	32.5	19.6	9.3	14.3	20.5	7.1	12.0	12.7
AEPNI					36.0	50.1	33.8	52.6	49.8			
AEPPJM					614.7	771.1	752.7	754.5	931.4			
ALTE					0.3	0.0	0.0	0.1	0.2	0.4	0.0	0.2
ALTW					5.3	9.2	6.0	6.3	3.7	1.1	1.0	1.7
AMRN					54.8	14.1	23.6	24.9	67.5	201.5	321.4	212.4
CILC					5.9	3.1	7.9	0.6	7.3	3.6	7.1	8.0
IP					253.9	233.4	212.7	290.3	352.6	844.3	957.8	928.5
MEC					2.7	3.5	6.0	5.9	24.8	29.6	40.4	33.3
NIPS					70.5	80.6	94.9	41.2	40.0	67.5	64.5	47.6
WEC					2.3	2.4	2.1	9.2	1.6	2.8	1.1	3.7
MECS										32.2	21.7	18.1
CPLE										63.2	41.5	99.6
CPLW										0.0	0.0	0.0
CIN										617.1	398.9	439.0
DUK										4.5	46.3	76.0
EKPC										34.9	21.8	14.2
IPL										25.7	19.9	15.1
LGEE										80.1	63.2	57.0
OVEC										830.4	746.7	864.8
TVA										9.7	86.5	136.7

Table 3-3 - Gross export volume by interface (MWh x 1,000): Calendar year 2004

Interface	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEP	13.1	22.0	16.7	22.0								
DLCO	50.2	68.3	43.1	34.5	175.6	104.6	67.2	55.5	35.0	123.6	140.2	207.5
FE	77.3	103.0	113.0	100.5	144.3	136.8	127.1	117.9	103.3	323.3	342.4	373.2
NYIS	865.5	875.3	1,086.0	854.8	562.1	844.8	696.5	714.7	801.1	1,283.2	1,134.3	821.1
VAP	16.0	21.9	21.9	67.2	105.9	118.6	107.3	68.8	48.3	453.4	567.5	488.7
AEPNI					1,327.3	1,281.3	1,342.6	1,355.0	1,464.8			
AEPPJM					86.0	97.9	50.8	27.8	18.6			
ALTE					115.3	100.9	93.4	100.3	98.6	102.5	100.7	108.9
ALTW					262.7	146.6	168.5	150.1	154.1	168.4	165.7	198.5
AMRN					84.7	122.6	108.3	144.3	58.3	263.7	165.7	258.0
CILC					1.3	14.8	1.2	4.5	3.5	0.1	0.2	0.6
IP					60.1	63.5	82.9	52.8	43.4	30.4	33.5	41.8
MEC					528.5	527.5	602.3	596.0	445.4	585.3	433.7	609.8
NIPS					159.9	83.2	124.4	303.7	192.3	20.5	12.5	13.6
WEC					420.2	312.5	270.5	177.8	338.9	259.6	280.8	358.2
MECS										828.3	845.1	922.8
CPLE										321.4	303.4	315.5
CPLW										73.1	69.3	72.1
CIN										142.2	688.4	414.7
DUK										320.4	177.0	312.7
EKPC										4.6	13.2	19.1
IPL										5.8	0.5	1.8
LGEE										1.9	2.8	4.6
OVEC										1.4	3.5	10.4
TVA										197.2	131.4	203.3

2004 Trends

With the integration of the ComEd Control Area, PJM's long-standing status as a net importer of power changed and PJM became a net exporter. In Phase 2, ComEd's net export volume exceeded the net import volume in the rest of the PJM system. PJM continued to be a net exporter after the integration of the AEP and DAY Control Zones. While most of ComEd's exports were at the PJM/AEPNI interface, PJM internalized the PJM/AEPNI and PJM/AEPPJM interfaces in Phase 3, yet continued to be a net exporter of power. Phase 3 exports were spread more evenly over multiple interfaces.

Changing Interfaces

New Interfaces

During 2004, PJM experienced two integrations, each of which changed the number of external interfaces. On May 1, 2004, when the ComEd Control Area became part of PJM, the RTO's boundaries were altered. The external interfaces changed from the five previous interfaces [NYIS, FE, DLCO, VAP and AEP] to a total of 14 external interfaces.

On October 1, when the AEP and DAY Control Zones became part of PJM, the boundaries shifted again. The number of external interfaces grew from 14 to 22.

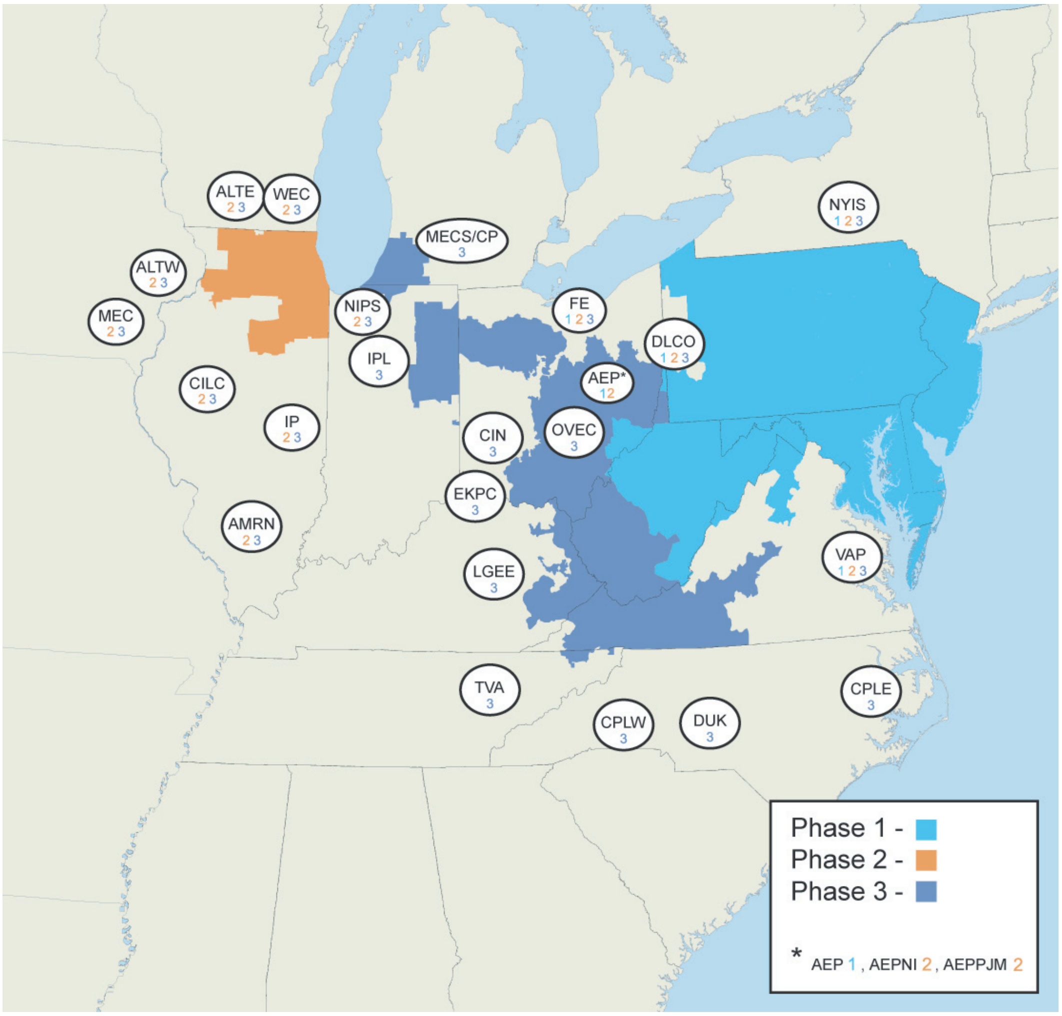
Table 3-4 shows the changes in interfaces during 2004.

Table 3-4 - Active interfaces: Calendar year 2004

Interface	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEP	Active	Active	Active	Active								
DLCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
VAP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AEPNI					Active	Active	Active	Active	Active			
AEPPJM					Active	Active	Active	Active	Active			
ALTE					Active	Active	Active	Active	Active	Active	Active	Active
ALTW					Active	Active	Active	Active	Active	Active	Active	Active
AMRN					Active	Active	Active	Active	Active	Active	Active	Active
CILC					Active	Active	Active	Active	Active	Active	Active	Active
IP					Active	Active	Active	Active	Active	Active	Active	Active
MEC					Active	Active	Active	Active	Active	Active	Active	Active
NIPS					Active	Active	Active	Active	Active	Active	Active	Active
WEC					Active	Active	Active	Active	Active	Active	Active	Active
MECS										Active	Active	Active
CPLE										Active	Active	Active
CPLW										Active	Active	Active
CIN										Active	Active	Active
DUK										Active	Active	Active
EKPC										Active	Active	Active
IPL										Active	Active	Active
LGEE										Active	Active	Active
OVEC										Active	Active	Active
TVA										Active	Active	Active

The approximate geographic location of these interfaces can be seen in Figure 3-4. The AEP interface had three variants in 2004, all of which are shown in Figure 3-4.

Figure 3-4 - PJM's evolving footprint and its interfaces



New Interface Pricing Points

Before ComEd's integration, the PJM interface pricing points had been: NYISO, AEPVPIMP, AEPVPEXP, FE, DLCO and the Ontario Independent Electricity System Operator (Ontario IESO). Interface pricing points differ from interfaces in that transactions can be scheduled to an interface based on a contract transmission path while pricing points are developed and applied based on the electrical impact of the external power source on PJM tie lines, regardless of the contract transmission path.[9] Interface pricing points were added and changed as PJM expanded in 2004. Table 3-5 illustrates which interface pricing points were used during each of the three phases of PJM's evolution during the year.

9 See Appendix D, "Interchange Transactions," for a more detailed discussion of interface pricing.

PJM establishes prices for transactions with external control areas by assigning interface pricing points to external control areas. The interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically. External control areas are either adjacent to PJM or not adjacent to PJM. Transactions between PJM and external control areas need to be priced at the PJM border. A set of external pricing points is used to create such interface prices. The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and an external control area and therefore to create price signals that embody the underlying economic fundamentals. Transactions between adjacent control areas and PJM flow on one or more physical tie lines that together constitute the interface between the two control areas.[10]

Table 3-5 - Active pricing points by interface: Calendar year 2004

Pricing Point	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEPVPEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active			
AEPVPIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active			
DLCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active			
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AEPNI					Active	Active	Active	Active	Active			
ALTENI					Active	Active	Active	Active	Active			
ALTWNI					Active	Active	Active	Active	Active			
AMRNNI					Active	Active	Active	Active	Active			
CILCNI					Active	Active	Active	Active	Active			
IPNI					Active	Active	Active	Active	Active			
IPPJMEXP					Active	Active	Active	Active	Active			
IPPJMIMP					Active	Active	Active	Active	Active			
MECNI					Active	Active	Active	Active	Active			
MECPJMEXP					Active	Active	Active	Active	Active			
MECPJMIMP					Active	Active	Active	Active	Active			
NIPSNI					Active	Active	Active	Active	Active			
NYISNIEXP					Active	Active	Active	Active	Active			
NYISNIIMP					Active	Active	Active	Active	Active			
WECNI					Active	Active	Active	Active	Active			
WECPJMEXP					Active	Active	Active	Active	Active			
WECPJMIMP					Active	Active	Active	Active	Active			
MICHFE										Active	Active	Active
NIPSCO										Active	Active	Active
NORTHWEST										Active	Active	Active
OVEC										Active	Active	Active
SOUTHEAST										Active	Active	Active
SOUTHWEST										Active	Active	Active

10 See Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Interchange Transaction Issues

TLRs

Data for Phase 3 indicate that PJM called fewer TLRs after the integration of the AEP and DAY Control Zones, that the reduced TLRs were primarily in the newly integrated control zones, that TLRs for the PJM Mid-Atlantic Region remained low and that the increase in TLRs in November and December over October was at a border facility affected by flows from a non-LMP market. Monthly average PJM TLRs declined by 60 percent, from 52 during Phase 2 to 21 in Phase 3. (See Figure 3-5.) A large proportion (45 percent) of these reductions came on flowgates located in AEP with an average of 18 TLRs per month in Phase 2 and four per month in Phase 3. PJM has been the control area reliability coordinator for AEP since February 2003 and in that capacity was responsible, among other functions, for calling TLRs to relieve transmission constraints. The flowgates on the border between PJM in Phase 2 and external control areas were the other primary source of reductions in TLRs in Phase 3. TLRs on flowgates in the PJM Control Area remained relatively unchanged, averaging between two and three per month. The number of unique flowgates for which PJM declared TLRs also declined, from an average of 13 different flowgates per month during Phase 2 to an average of six different flowgates per month in Phase 3. (See Figure 3-6.) Of the 63 TLRs called by PJM in Phase 3, 60 percent were on just one flowgate, Wylie Ridge, a facility particularly impacted by flow from the FE control area. Since FE is not part of PJM, TLRs are a primary method of constraint relief for Wylie Ridge. As with other chronically constrained facilities, TLRs for this constraint could be reduced through LMP-based redispatch if the generating units in the FE control area were available for such redispatch. While PJM does have an agreement with FE with regard to the redispatch of the Sammis Generating Station for congestion management, this was not adequate to entirely address the constraint issues at Wylie Ridge.[11]

Before the Phase 3 integration, PJM routinely called TLRs to relieve transmission constraints in the AEP control area on facilities like the Kanawah-Matt Funk 345 kV line and the Kammer Transformer. These AEP transmission constraints were integrated into PJM in Phase 3. As a result, TLRs for AEP have been reduced. Historically, these facilities had been responsible for the majority of PJM's declared TLRs. For example, flowgate 2403 (Kanawah-Matt Funk 345) had a monthly average of three TLRs from January 2003 through September 2004. In Phase 3, this number was reduced to an average of less than one TLR per month.

11 See "Amended and Restated Operating Agreement of PJM Interconnection, L.L.C." (December 30, 2004), p. Original Sheet No. 141D < http://www.pjm.com/documents/ downloads/agreements/oa.pdf > (613 KB).

Figure 3-5 - PJM and Midwest ISO transmission loading relief (TLR) procedures: 2003 and 2004

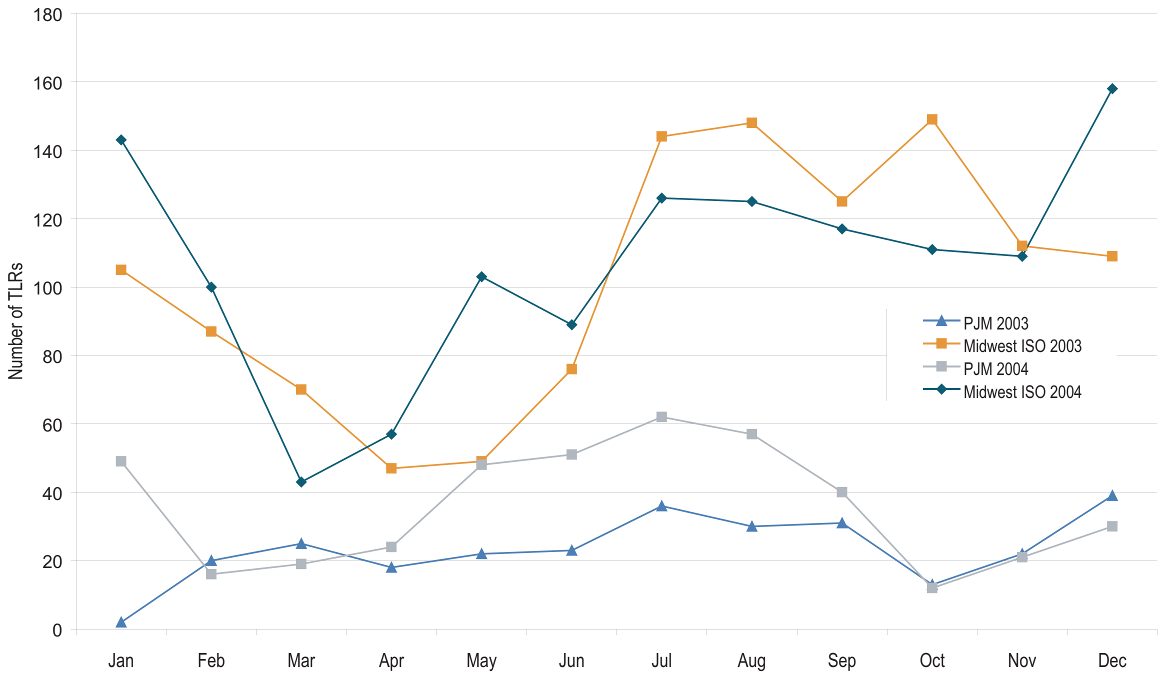
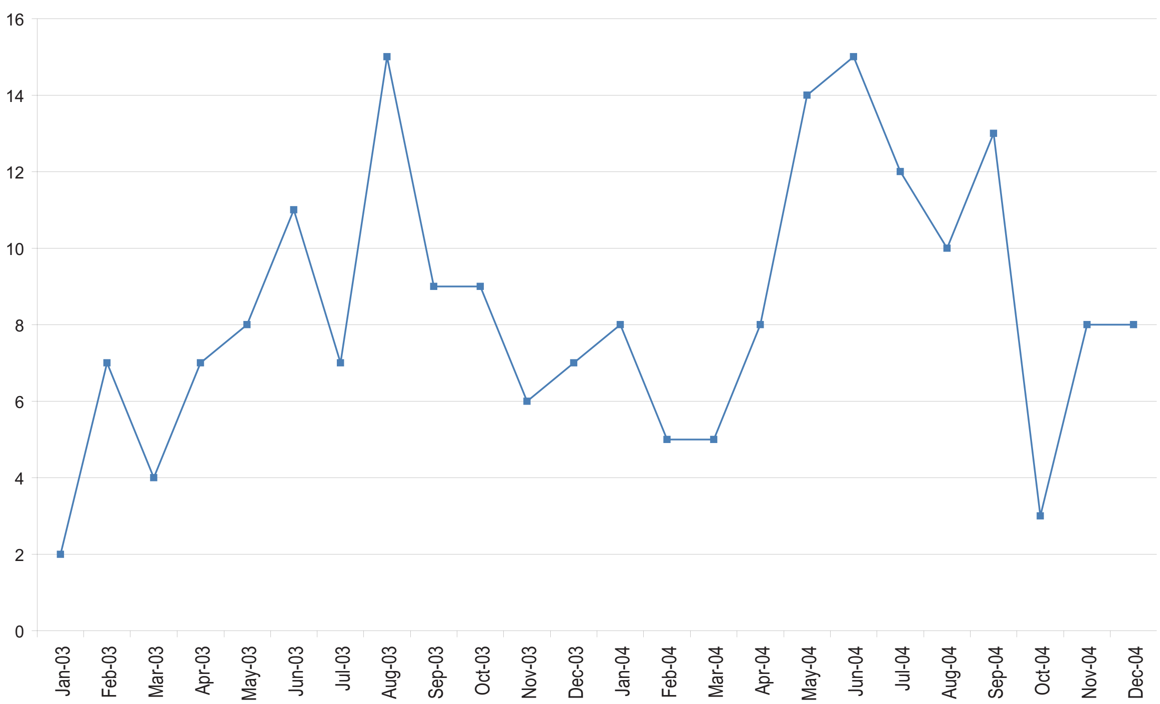


Figure 3-6 - Number of unique PJM flowgates: Calendar years 2003 to 2004



Following the completion of the Phase 3 integrations, the general relationship between the number of TLRs declared by the Midwest ISO and the number declared by PJM has continued. (See Figure 3-5.) Reliance on economic redispatch in response to pricing signals reduces the need to call TLRs to resolve constraints within an RTO although not necessarily at the border between an LMP market and a contract path market. The Midwest ISO system currently relies on TLRs to provide relief, but is expected to rely on redispatch when its power markets begin to operate.

The PJM/ Midwest ISO Joint Operating Agreement (JOA)

PJM and the Midwest ISO entered into a JOA that became effective on March 1, 2004, in anticipation of the integration of ComEd, AEP and DAY and their power flow effects. The JOA specifically indicated that "[…] certain other electric utilities will be integrated into the systems and markets PJM administers and controls, and it is recognized that such integration may result in changed flows on the system of PJM and the Midwest ISO as they exist prior to such integration."[12] A major part of the JOA dealt with congestion management at the "seams" of the control areas. As a market-based system, PJM controls congestion through LMP while the Midwest ISO will continue to use TLRs for congestion control until it introduces markets.[13] The JOA addresses issues so as to consistently ensure that parallel path flows and impacts are recognized and managed consistent with ensuring system reliability.[14]

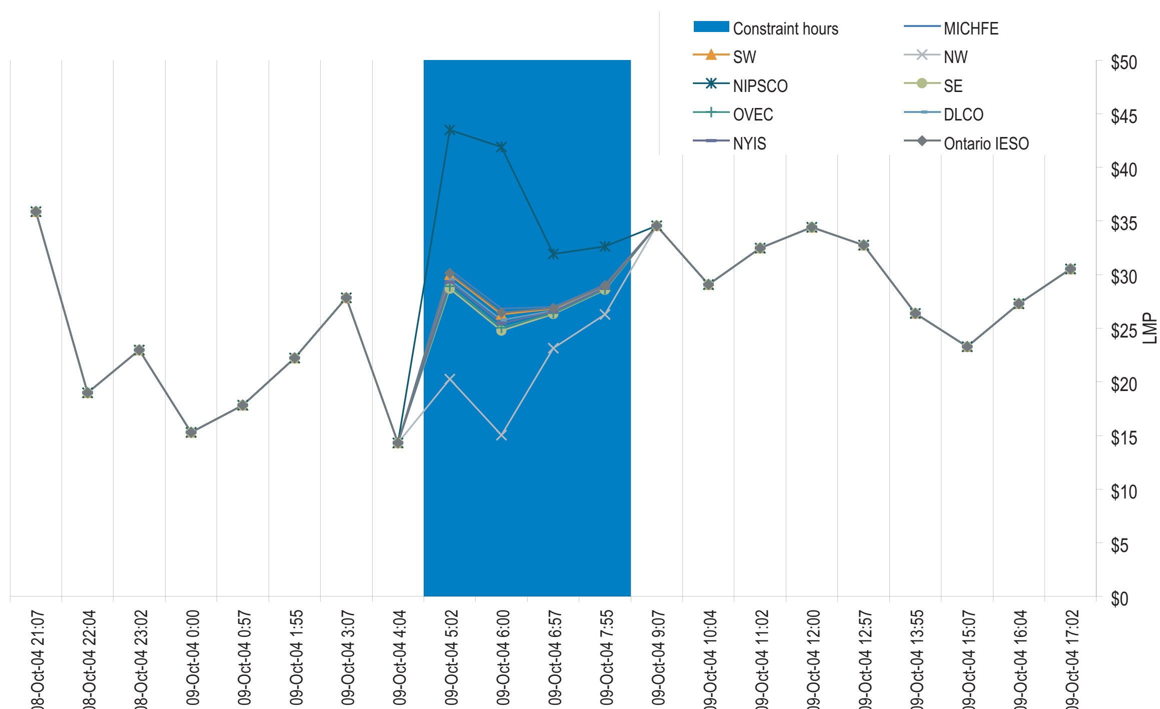
The JOA includes a list of flowgates[15] where PJM and the Midwest ISO plan a coordinated response to congestion events and for which PJM will redispatch generation to aid in reducing congestion.[16] Generally, the JOA describes a process whereby the flows of power within PJM (the market-based entity) which impact a coordinated flowgate are categorized as "firm" and "non-firm" flows.[17] Firm power flows are those from designated network resources used to serve designated network loads and firm point-to-point network and native load (NNL) customers. All other flows are categorized as economic dispatch "non-firm" flows. Further, each unit within PJM that is contributing to these flows is identified. This categorization of power flows and identification of units contributing to those flows allows the power flows in PJM's market system to be compatible with the transmission service categories used in a TLR-based congestion management system. When a congestion event on a coordinated flowgate occurs, units can be redispatched and/or TLRs can be called to provide the most effective relief in a consistent manner.

During October 2004, a number of coordinated flowgates in the Midwest ISO experienced congestion and PJM redispatched generation to provide relief. When PJM redispatches for flowgate control, LMP increases on the congested side, but falls on the uncongested side. These price movements are economic signals that represent the relative value of generation and load in areas surrounding the constraint. Figure 3-7 depicts such actions at a time when a coordinated flowgate was actually constrained.

12 See the JOA between the Midwest ISO and PJM (December 31, 2003), Original Sheet No. 3 <http://www.pjm.com/ documents/downloads/agreements/joa-complete.pdf> (906 KB).
13 In the future the Midwest ISO will transition to a market-based system. At that time, the Phase 2, market-to-market of this JOA will be implemented.
14 See generally the JOA between the Midwest ISO and PJM (December 31, 2003) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (906 KB).
15 "Flowgate refers to a representative modeling of facilities or groups of facilities that may act as potential constraint points on the regional system." See the JOA between the Midwest ISO and PJM (December 31, 2003), Substitute Original Sheet No. 8 (Issued April 2, 2004) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (906 KB).
16 "Coordinated flowgate or (CF) shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of the Congestion Management Process. For a Market-Based Operating Entity, these Flowgates will be subject to the requirements of the congestion management portion of the Congestion Management Process (Sections 4 and 5). A coordinated flowgate may be under the operational control of a third party." JOA, Substitute Original Sheet No. 34 (Issued April 2, 2004). PJM and the Midwest ISO are operating entities.
17 See the JOA between the Midwest ISO and PJM (December 31, 2003), Attachment 2, "Congestion Management Process" (Issued April 2, 2004), p. 101 <http://www.pjm.com/ documents/downloads/agreements/joa-complete.pdf> (906 KB).

The Crete – St. Johns Tap 345 kV line, located near the southern tip of Lake Michigan, is one of several facilities that have experienced constrained conditions. Congestion there results from power flows around the tip of Lake Michigan from northwest Indiana into Michigan. When these flow patterns develop and cause congestion, PJM's redispatch of generating units results in a pricing arrangement that lowers LMP on the western, uncongested side of the constraint, but raises it on the eastern, congested side. One way to observe this relationship is to examine pricing point LMPs during an actual event. (See Figure 3-7.) In this example, on the morning of October 9th, when the Crete – St. Johns Tap flowgate was constrained, the NIPSCO pricing point (constrained side) LMP rose to over $43 while the Northwest pricing point LMP fell to $15. This $28 difference in LMP represents the result of PJM's redispatch actions to reduce congestion on the flowgate. After the constraint had cleared, LMP separation ceased and PJM's pricing point LMPs were again equal.

Figure 3-7 - Midwest ISO constraints and pricing point LMPs: October 8 to 9, 2004



If one starts with an uncongested system (represented by equal pricing point LMPs), LMP at one or more pricing points will increase while LMP at others will decrease during a congestion event. In the example, one sees that all PJM pricing points have the same LMP (all lines are drawn on top of each other) in the hours before the constrained period (blue-shaded area). During the time of constraint, price separation at the pricing points (and elsewhere) occurs when units are redispatched and the congestion is resolved. Generally, because the redispatching process adds generation that is more expensive than that running before the event, LMP rises. The economic dispatch process brings the output of the lower-priced generation to the point that any further output from it aggravates the constraint. Then higher-priced units, located on the side of the constraint that needs additional power, begin to produce it. One sees in the blue-shaded area that pricing point LMPs change relative to each other during the congestion event. The NIPSCO pricing point LMP moves in a higher direction while the Northwest pricing point LMP moves lower. The other pricing point LMPs also change, but not as significantly as those associated with NIPSCO and Northwest. Their pricing points carry the greatest burden of congestion at the Crete – St. Johns Tap facility. A constraint on another facility would cause a different pattern of separation. One should note, however, that the other pricing point LMPs do change with congestion at Crete – St. Johns Tap. The magnitude of a constraint's impact on any pricing point is clear from the amount of change in its LMP. After the redispatching process has relieved the constrained facility, the system comes to equilibrium and pricing point LMPs are all equal again. When one looks at PJM during the October 2004 congestion events of the coordinated flowgates, the average high price was $43.30 and the average low was $19.32. The greatest separation was $104.08.

Price separation at pricing points also occurs when facilities other than coordinated flowgates are congested. If one were to compare the variability of pricing point LMPs during periods of constrained and unconstrained operation of coordinated flowgates, one would see that price separation at the pricing points is higher when the coordinated flowgates are constrained. This is true, even if congestion is present elsewhere when the coordinated flowgates are unconstrained.

In October 2004, the standard deviation of pricing point LMPs was $2.32 in the hours when none of the coordinated flowgates were congested. This value provides a reference point. During the hours when coordinated flowgates were congested, the average standard deviation of the LMPs was $6.72, or almost triple the price variance experienced when the coordinated flowgates were uncongested. Congestion on coordinated flowgates causes a much greater variance in interface pricing point LMP than occurs when other parts of the system are congested.

Actual Versus Scheduled Power Flows

Loop flow is one reason that actual and scheduled flows may not match at a particular interface. Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths that the energy takes. Even when energy is scheduled on a path consistent with its expected actual flow, other loop flows can cause some of the energy to flow on another path. Outside of PJM's LMP-based Energy Market, energy is scheduled and paid for based on contract path although actual, associated energy deliveries flow on the path of least resistance. Loop flow can also occur when a transaction is scheduled between two external control areas, and some or all of the actual flows occur at PJM interfaces. Loop flow can result when transactions are scheduled into or out of PJM on one interface, but actually flow on another interface. PJM can only manage loop flow based on contract paths between external systems using TLR procedures. Loop flow based on gaming PJM price differentials can be managed, in part, by improving the pricing of transactions at the PJM interfaces.

Although total PJM net scheduled and actual flows were approximately equal in 2004, such was not the case for each individual interface. (See Table 3-6.) As a general matter, PJM operates so as to balance overall actual and scheduled interchange, but does not attempt to maintain a balance between actual and scheduled interchange at individual interfaces.

During Phase 1, for PJM as a whole, net scheduled and actual interface flows were comparatively balanced. Actual system imports were 7.0 million MWh, below the scheduled total of 7.4 million MWh by less than 0.4 million MWh or approximately 5 percent. Flow balance varied, however, at each individual interface. The PJM/NYIS interface was the most imbalanced, with net actual exports exceeding scheduled by 1.4 million MWh or 47 percent, for an average of 491 MW during each hour of the period. At the PJM/AEP interface, net actual imports exceeded scheduled by 0.5 million MWh or 11 percent. At the PJM/FE interface, net scheduled imports exceeded actual by less than 0.3 million MWh or 5 percent. At the PJM/DLCO interface, net actual imports exceeded scheduled by 0.6 million MWh or 184 percent. At the PJM/VAP interface, net actual imports exceeded scheduled by 0.2 million MWh or 66 percent.

During Phase 2, for PJM as a whole, net scheduled and actual interface flows were comparatively balanced. Actual system exports were 5.6 million MWh, equaling the scheduled total of 5.6 million MWh. Flow balance varied, however, at each individual interface. The PJM/AEPPJM interface was the most imbalanced, with net actual imports exceeding scheduled by 3.0 million MWh or 86 percent, for an average of 825 MW during each hour. At the PJM/NYIS interface, net actual exports exceeded scheduled by 2.8 million MWh or 164 percent.

During Phase 3 of 2004, for PJM as a whole, net scheduled and actual interface flows were comparatively balanced. Actual system exports were 3.6 million MWh, exceeding the scheduled total of 3.7 million MWh by 0.1 million MWh or 2 percent. Flow balance varied, however, at each individual interface. The PJM/MECS interface was the most imbalanced, with net actual exports exceeding scheduled by 1.6 million MWh or 71 percent, for an average of 722 MW during each hour of the period. At the PJM/TVA interface, net actual imports exceeded net scheduled exports by 1.5 million MWh or 413 percent. At the PJM/IP interface, net scheduled exports exceeded actual by 1.4 million MWh or 62 percent. At the PJM/OVEC interface, net actual imports exceeded scheduled by 1.2 million MWh or 55 percent.

Table 3-6 - Net scheduled and actual PJM interface flows (MWh x 1,000): Calendar year 2004

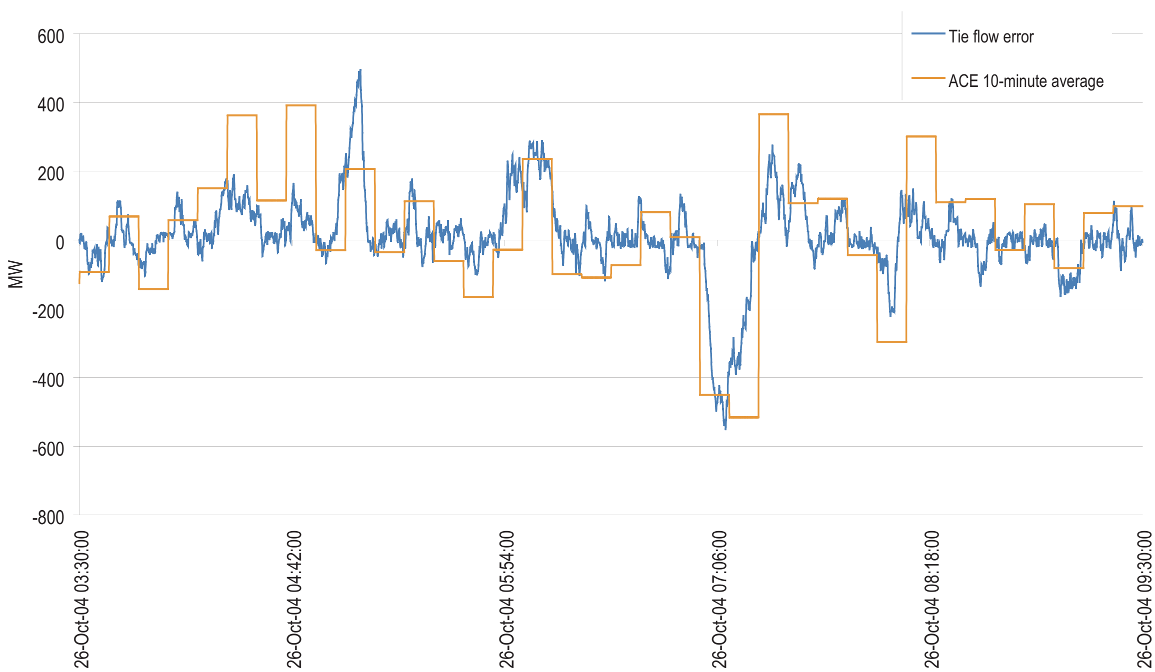
Interface	Actual	Net scheduled	Difference	Difference (Percent)
AEP	5,080	4,571	509	11%
DLCO	863	304	560	184%
FE	4,937	5,190	-252	-5%
NYIS	-4,487	-3,060	-1,427	47%
VAP	605	364	240	66%
Phase 1 System	6,999	7,369	-370	-5%
AEPPJM	6,574	3,543	3,031	86%
AEPNI	-4,323	-6,549	2,226	-34%
WEC	202	-1,502	1,704	-113%
AMRN	-751	-333	-417	125%
ALTE	-2,603	-508	-2,095	412%
IP	43	1,040	-997	-96%
CILC	367	-1	368	-65917%
NIPS	-2,150	-536	-1,613	301%
ALTW	-1,183	-851	-332	39%
MEC	-1,914	-2,657	743	-28%
DLCO	746	168	579	345%
FE	5,016	4,626	390	8%
NYIS	-4,551	-1,726	-2,825	164%
VAP	-1,109	-353	-756	214%
Phase 2 System	-5,635	-5,640	5	-0%
CPLE	102	-654	756	-116%
CPLW	-650	-193	-458	237%
DUK	-772	-525	-247	47%
EKPC	57	37	21	56%
OVEC	3,345	2,161	1,184	55%
TVA	1,132	-362	1,494	-413%
CIN	1,004	89	914	1024%
IPL	1,194	45	1,148	2534%
LGEE	191	173	18	10%
MECS	-3,841	-2,246	-1,594	71%
WEC	236	-769	1,005	-131%
AMRN	300	35	265	761%
ALTE	-1,602	-277	-1,325	479%
IP	903	2,351	-1,448	-62%
CILC	502	13	489	3831%
NIPS	-967	126	-1,093	-865%
ALTW	-640	-464	-176	38%
MEC	-746	-1,391	644	-46%
DLCO	333	-102	435	-425%
FE	1,116	1,992	-876	-44%
NYIS	-3,746	-2,427	-1,319	54%
VAP	-1,079	-1,312	233	-18%
Phase 3 System	-3,630	-3,700	70	-2%

Transactions and PJM Area Control Error (ACE)

A critical operations function for PJM is balancing load and generation on a real-time basis. The ACE metric defines this balance.[18] The net contribution of external transactions is an important component of the generation element of ACE. Import and export transactions are netted and the result is added to the generation component of ACE. When the sum of scheduled and the sum of actual power flows to or from external areas differ, a deviation between generation and load is created. This is equivalent to a generator that is dispatched, but then over- or under-generates compared to the expected output level. When PJM experiences ACE deviation, the difference between actual and scheduled transaction power flows can be part of the reason. This is termed tie flow error.

Figure 3-8 provides an example of the contribution of tie flow error to ACE deviation. The ACE measurement (actually a 10-minute average of the ACE) is plotted against the tie flow error. There is a positive correlation between the level of tie flow errors and ACE deviation. The mismatch between scheduled and actual flow contributes to the ACE deviation and thus requires corrective action by PJM.

Figure 3-8 - Contribution of tie flow error to area control error (ACE)



PJM and NYISO Transaction Issues

If the interface prices were defined in a comparable manner by PJM and the NYISO, if there were identical rules governing external transactions in PJM and the NYISO, if there were not time lags built into the rules governing such transactions and if there were no risks associated with such transactions, prices at the interfaces would be expected to be very close and the level of transactions

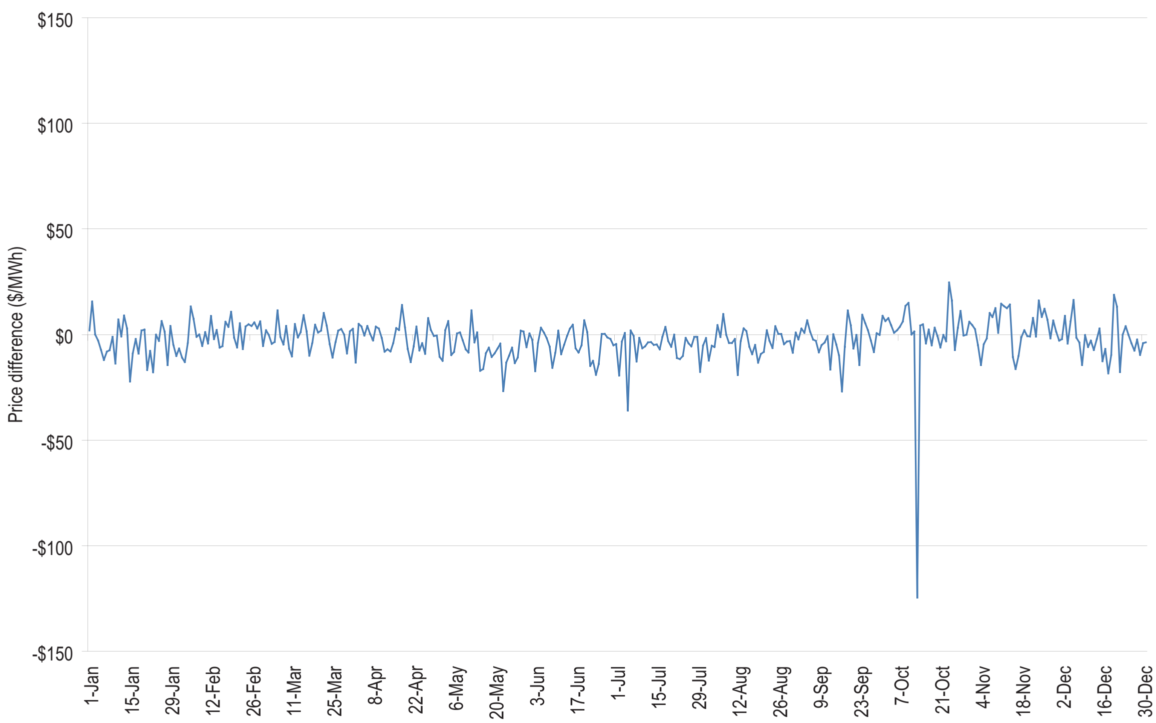
18 See Appendix F, "Ancillary Service Markets."

would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[19]

PJM's price for transactions with the NYISO, termed the NYIS pricing point by PJM, represents the value of power at the PJM-NYISO border, as determined by the PJM Market. Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO-PJM border, as determined by the NYISO market.

The 2004 hourly average prices for PJM/NYIS and the NYISO PJM proxy bus price were $46.72 and $44.33, respectively. The simple average difference between the PJM/NYIS interface price and the NYISO PJM proxy bus price increased and changed sign from 2003 to 2004 yet remained relatively small and the variability in the difference decreased. The simple average PJM NYISO interface price difference was $0.34 per MWh in 2003 and $-2.39 per MWh in 2004. (See Figure 3-9.) The PJM/NYIS price was higher on average than the NYISO PJM proxy bus price in 2004. This reverses the prior pattern where the NYISO PJM proxy bus price was higher than the PJM/NYIS price. The fact that PJM's net export flow volume for 2004, at 7.4 million MWh, is 28 percent lower than the three-year, 2001-to-2003 average is at least partially consistent with the change in the simple average price difference. While relatively small, the simple average interface price difference does not reflect the continuing, substantial underlying hourly variability in prices during 2003 and 2004.

Figure 3-9 - Daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2004



19 See also the discussion of these issues in the *2003 State of the Market Report*, Section 3, "Interchange Transactions."

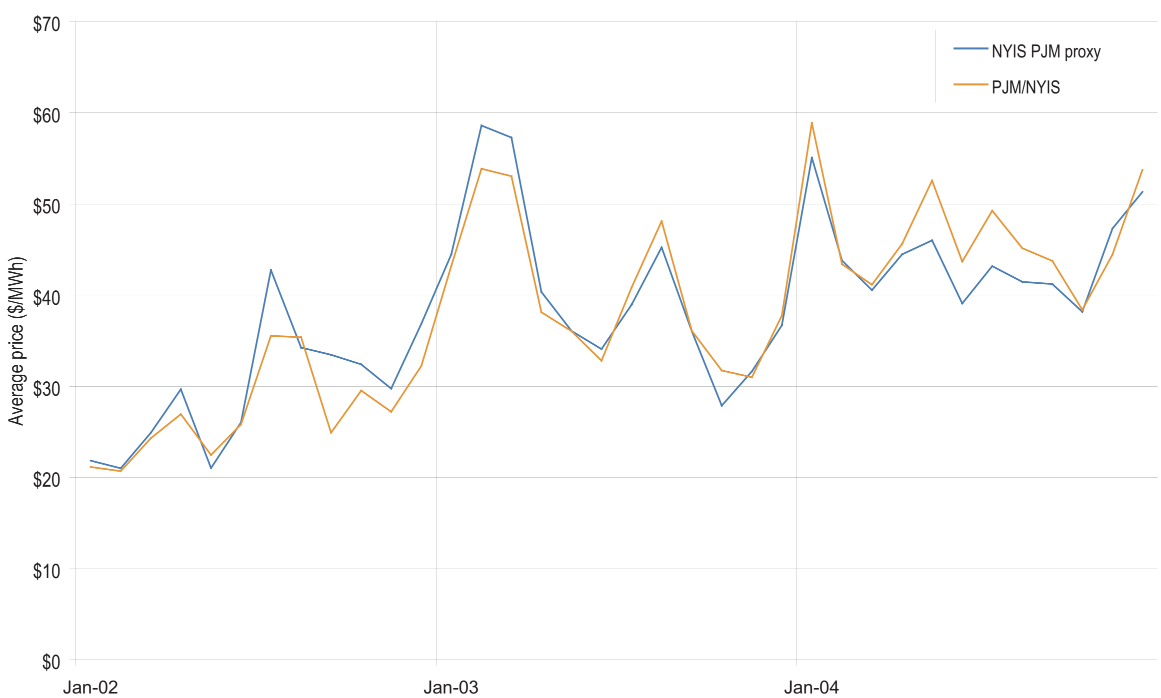
The difference between the PJM/NYIS interface price and the NYISO PJM proxy bus price fluctuated between positive and negative about eight times per day during 2003 and 2004. The number of times that the price difference fluctuated remained relatively constant over the period.

Standard deviation is a direct measure of variability. The standard deviation of hourly price was $25.00 in 2003 and $23.64 in 2004 for the PJM/NYIS price, but $37.72 in 2003 and $30.00 in 2004 for the NYISO PJM proxy bus price. The standard deviation of the difference in interface prices was $36.21 in 2003 and $29.55 in 2004. The absolute value of the price differences is another measure of price variability. The average of the absolute value of the hourly price difference was $16.13 in 2003 and $14.01 in 2004. Absolute values reflect the price differences without regard to whether they are positive or negative.

A number of factors are responsible for the observed relationship between interface prices. The fact that the simple average of interface prices is relatively small suggests that competitive forces prevent price deviations from persisting. That is further supported by the frequency with which the price differential switches between positive and negative. However, continuing significant variability in interface prices is consistent with the fact that interface prices are defined and established differently, making it difficult for prices to equalize, regardless of other factors.

In addition to small, average interface price differences and to large hourly price differences, there is a significant correlation between monthly average hourly PJM and NYISO interface prices during the entire period 2002 to 2004. Figure 3-10 shows this correlation between hourly PJM and NYISO interface prices.

Figure 3-10 - Monthly hourly average NYISO PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2004



SECTION 4 - CAPACITY MARKETS

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

The PJM Capacity Credit Market[2] and the ComEd Capacity Credit Market[3] provide 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,[4] Monthly and Multimonthly Capacity Credit Markets. The ComEd Capacity Credit Market consists of Interval, Monthly and Multimonthly Capacity Credit Markets. Each 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.

In the *2004 State of the Market Report*, the calendar year is divided into three phases, corresponding to market integration dates.

- **Phase 1.** The four-month period from January 1 through April 30, 2004, when PJM was comprised of 12 zones.[5] Eleven of these [i.e., 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)] comprised the Mid-Atlantic Region. The remaining zone, the Allegheny Power Company Control Zone (AP), comprised the PJM Western Region.

- **Phase 2.** 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).[6]

- **Phase 3.** 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.

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 All ComEd Capacity Market values (capacities) are in terms of installed MW.
4 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.
5 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The 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 the 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.
6 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).

During Phase 1, PJM operated one Capacity Market for the Mid-Atlantic Region and the AP Control Zone. That market remained intact during Phase 2 when a separate Capacity Credit Market was created and became effective on June 1, 2004, for the ComEd Control Area. During the first month of the Phase 2 period, the Commonwealth Edison Company satisfied the area's requirements under the guidance of PJM. [7]

During Phase 3, the AEP and DAY Control Zones were integrated into the PJM Capacity Market that operated for all zones except ComEd, which continued to operate based on a separate set of PJM rules.

The calendar year ended with PJM operating two Capacity Markets. The PJM Capacity Market (or simply PJM) was comprised of the 11 control zones of the Mid-Atlantic Region, the AP Control Zone and the newer AEP and DAY Control Zones. The ComEd Capacity Market was comprised solely of the ComEd Control Zone. These two Capacity Markets are scheduled to be combined into a single Capacity Market effective June 1, 2005. [8]

Overview

The PJM Market Monitoring Unit (MMU) analyzed key measures of PJM Capacity Market and of ComEd Capacity Market structure and performance for 2004, including concentration ratios, prices, outage rates and reliability. The MMU found serious market structure issues, but no exercise of market power during 2004.

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 ultimate test of the markets is the actual performance of the market, measured by price and the relationship between price and marginal cost. For example, at times market participants behave in a competitive manner even within a non-competitive 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 PJM Capacity Market results were competitive during 2004. The ComEd Capacity Market results were reasonably competitive in 2004. Market power remains a serious concern for the MMU in both Capacity Markets based on market structure conditions in those markets.

7 "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. 48C – 48D, Section L.
8 For purposes of this "Capacity Section" and its Appendix, these markets are identified as the PJM Capacity Market (or PJM) and the ComEd Control Zone Capacity Market, the ComEd Capacity Market (or ComEd). These markets are referred to collectively as the Capacity Markets for the RTO.

Market Structure

The PJM Capacity Market

Ownership Concentration

- **Phases 1 and 2.** Structural analysis of the PJM Capacity Credit Market found that its short-term markets exhibited moderate concentration while its long-term markets exhibited high concentration levels during the period January through September 2004.

- **Phase 3.** Structural analysis of the PJM Capacity Credit Market found that its short-term markets exhibited moderate concentration while its long-term markets exhibited high concentration levels during the period October through December 2004.

Demand

- **Phases 1 and 2.** During January through September 2004, electricity distribution companies (EDCs) and their affiliates accounted for 76 percent of the PJM Capacity Markets' load obligations.

- **Phase 3.** During October through December 2004, EDCs and their affiliates accounted for 80 percent of the PJM Capacity Markets' load obligations.

Supply and Demand

- **Phases 1 and 2.** During the first and second intervals of 2004, installed capacity, unforced capacity and obligations grew in the PJM Capacity Market. Compared to the same period of 2003,[9] average installed capacity increased by 7,781 MW or 11.1 percent to 77,673 MW, while average unforced capacity rose by 6,267 MW or 9.5 percent to 72,415 MW. Average load obligations climbed by 6,502 MW or 10.1 percent to 70,797 MW, or 1,618 MW less than average unforced capacity. Overall capacity credit market transactions increased by more than 20.0 percent during the first and second intervals. Daily capacity credit market volume increased by 60.1 percent, while monthly and multimonthly capacity credit market volume increased by 63.1 percent and 0.7 percent, respectively.

- **Phase 3.** During the third interval of 2004, installed capacity, unforced capacity and obligations increased with the integration of the AEP and DAY Control Zones into the PJM Capacity Market. Average installed capacity increased to 116,770 MW. Average unforced capacity rose to 108,422 MW. Average load obligation climbed to 98,906 MW. Compared to the first two intervals, the overall capacity credit market volume in the third interval decreased by nearly 7.0 percent. Daily capacity credit market volume decreased by 9.3 percent, while monthly capacity credit market volume decreased by 29.6 percent and multimonthly capacity credit market volume increased by 2.3 percent.

9 The AP Control Zone obligations were met under an available capacity construct prior to the second interval of 2003 and, therefore, not included in these values.

The ComEd Capacity Market

Ownership Concentration

- **Phases 2 and 3 (June through December 2004).** Structural analysis of the ComEd Capacity Credit Market found that its long-term markets exhibited high levels of concentration from June 1 of Phase 2, through Phase 3, 2004.

Demand

- **Phases 2 and 3 (June through December 2004).** During the seven-month period ended December 31, 2004, EDCs accounted for 86 percent of the load obligation in the ComEd Capacity Market.

Supply and Demand

- **Phases 2 and 3 (June through December 2004).** During the seven-month period ended December 31, 2004, capacity resources exceeded capacity obligations in the ComEd Capacity Market every month, resulting in an average net excess of 5,672 MW for the period.

Market Performance

The PJM Capacity Market

Capacity Credit Market Volumes

- **Phases 1 and 2.** During the first interval of 2004, PJM Capacity Credit Markets experienced moderate activity. On average 994 MW traded in the Daily Market. Trades in the Monthly and Multimonthly Markets averaged 1,199 MW and 2,619 MW, respectively.[10]

  During the second interval of 2004, activity in the PJM Capacity Credit Markets increased. On average 1,203 MW traded in the Daily Market. Trades in the Monthly and Multimonthly Markets averaged 971 MW and 3,325 MW, respectively.

- **Phase 3.** With the Phase 3 integration of the AEP and DAY Control Zones into PJM, Capacity Credit Markets experienced slightly less activity. An average 986 MW traded in the Daily Market. Trades in the Monthly and Multimonthly Markets averaged 773 MW and 3,002 MW, respectively.

10 Unless otherwise noted, all volume measures in the Capacity Market Section are in MW-days.

Capacity Credit Market Prices

- **Phases 1 and 2.** During the first interval of 2004, PJM daily capacity credit market prices were low, averaging $0.51 per MW-day. Prices in the Monthly and Multimonthly Markets declined slightly over the period from $11.72 per MW-day in January to $7.26 per MW-day in May, averaging $8.38 per MW-day for the first interval.

  During the second interval of 2004, daily capacity credit market prices were higher, averaging $44.79 per MW-day. The daily capacity credit market price peaked in June 2004 at $110.61 per MW-day. Prices in the Monthly and Multimonthly Markets increased in June and then decreased over the remainder of the period from $33.60 per MW-day in June to $25.39 per MW-day in September, averaging $31.53 per MW-day for the second interval.

- **Phase 3.** During the third interval of 2004, daily capacity credit market prices were low, averaging $0.40 per MW-day. Prices in the Monthly and Multimonthly Capacity Markets declined slightly over the interval from $14.19 per MW-day in October to $12.36 per MW-day in December, averaging $13.17 per MW-day for the third interval.

The ComEd Capacity Market

Capacity Credit Market Volumes

- **Phases 2 and 3.** The ComEd monthly and multimonthly capacity credit market volumes averaged 1,299 MW, or about 6 percent of the average capacity obligation for the seven months ended December 31, 2004.

Capacity Credit Market Prices

- **Phases 2 and 3.** Volume-weighted average prices in the ComEd Capacity Credit Market ranged from a low of $24.17 per MW-day in December 2004, to a high of $32.26 per MW-day in July.

Generator Performance

From 1996 to 2001, the average, PJM equivalent demand forced outage rate (EFORd) trended downward, reaching 4.8 percent in 2001, but then increased to 5.2 percent in 2002 and 7.0[11] percent in 2003. In 2004, the average PJM EFORd continued its upward trend, reaching 8.0 percent. Approximately half the increase in EFORd from 2003 to 2004 was the result of increased forced outage rates of fossil steam units, while the balance of the increase was the result of increased forced outage rates of combustion turbine, nuclear and hydroelectric units. These forced outage rates are for the PJM Mid-Atlantic Region and the AP Control Zone only. The forced outage rate in 2004 was 7.9 percent for all zones within the PJM Capacity Market (including the AEP, DAY and ComEd Control Zones).[12]

11 The 2003 EFORd reported in the 2003 State of the Market Report was 7.1 percent, Final EFORd data were not available until after the publication of the report. The 2004 EFORd reported here will also be revised based on final data submitted after the publication of the report.
12 In some cases the data for the AEP, DAY and ComEd Control Zones may be incomplete for the year 2004 and as such, only data that have been reported to PJM were used.

Conclusion

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 likelihood of the exercise of market power is high. These structural conditions are more severe in the ComEd Capacity Market than in the PJM Capacity Market. Market power is endemic to the structure of PJM Capacity Markets. Supply and demand fundamentals offset these market structure issues in the PJM Capacity Market in 2004, producing competitive results in the PJM Capacity Market and reasonably competitive results in the ComEd Capacity Market.

Market Structure for the PJM Capacity Market

Ownership Concentration

Phases 1 and 2

Concentration ratios[13] are a summary measure of market share, a key element of market structure. High 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 MMU structural analysis indicates that the PJM Capacity Credit Markets in the first and second intervals of 2004 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 4-1, HHIs for the Daily Capacity Credit Market averaged 1373 during the first and second intervals of 2004, with a maximum of 3096 and a minimum of 1050 (four firms with equal market shares would result in an HHI of 2500). HHIs for the longer term Monthly and Multimonthly Capacity Credit Markets averaged 3319, with a maximum of 8900 and a minimum of 1114 (three firms with equal market shares would result in an HHI of 3333). On average, 1,087 MW were traded in the Daily Capacity Credit Market and 4,031 MW were traded in the Monthly and Multimonthly Capacity Credit Markets. The total of 5,118 MW represented, on average, 7.2 percent of total load obligation for the period of which 1.5 percent was attributable to the Daily Capacity Credit Market and 5.7 percent was attributable to the Monthly and Multimonthly Capacity Credit Markets.

13 See Section 2, “Energy Market,” for a more detailed discussion of concentration ratios and the HHI.

Table 4-1 - PJM Capacity Market HHI: Calendar year 2004

Term	Statistic	Daily Market HHI	Monthly and Multimonthly Market HHI
Phases 1 and 2	Average	1373	3319
	Minimum	1050	1114
	Maximum	3096	8900
Phase 3	Average	1631	2608
	Minimum	1292	1316
	Maximum	2561	4151
Calendar Year	Average	1516	3031
	Minimum	1050	1114
	Maximum	3096	8900

Table 4-2 - PJM Capacity Market residual supply index (RSI): Calendar year 2004

Term	Statistic	Daily Market RSI	Monthly and Multimonthly Market RSI
Phases 1 and 2	Average	1.72	0.61
	Minimum	0.44	0.01
	Maximum	2.51	2.36
Phase 3	Average	6.22	2.95
	Minimum	2.11	0.26
	Maximum	9.97	14.92
Calendar Year	Average	4.21	1.74
	Minimum	0.44	0.01
	Maximum	9.97	14.92

Table 4-2 shows residual supply index (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 is a measure of the extent to which generation owners are pivotal suppliers in the PJM Capacity Market. A generation owner is pivotal if the capacity of the owner's generation facilities is needed to meet the demand for capacity. When a generation owner is pivotal, it has the ability to affect market price. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.0 clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power. As an example, suppliers can be jointly pivotal. If the RSI is greater than 1.00, 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 1.00, 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 RSI results for the Daily Capacity Credit Market indicate that the RSI fell below 1.0 in 73 (27 percent) of the daily auctions, while the average level was 1.72. The RSI results for the Monthly and Multimonthly Markets indicate that the average RSI was 0.61 with 44 of the monthly auctions (81 percent) having RSI values less than 1.0. These results are consistent with the conclusion that there were significant structural issues in the Capacity Markets in PJM in Phases 1 and 2.

Phase 3

The MMU structural analysis indicates that the PJM Capacity Credit Markets in the third interval of 2004, after the integration of the AEP and DAY Control Zones, 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 4-1, HHIs for the Daily Capacity Credit Market averaged 1631 during the last interval of 2004; with a maximum of 2561 and a minimum of 1292 (three firms with equal market shares would result in an HHI of 3333). HHIs for the longer term Monthly and Multimonthly Capacity Credit Markets averaged 2608, with a maximum of 4151 and a minimum of 1316. On average 986 MW were traded in the Daily Capacity Credit Market and 3,775 MW were traded in the Monthly and Multimonthly Capacity Credit Markets. The total of 4,761 MW represented, on average, 4.8 percent of total load obligation for the period, of which 1.0 percent was attributable to the Daily Capacity Credit Market and 3.8 percent was attributable to the Monthly and Multimonthly Capacity Credit Markets.

RSI results for Phase 3 indicate that RSI levels were higher for both the Daily Capacity Credit Markets and the Monthly and Multimonthly Capacity Credit Markets than in Phases 1 and 2. However, the RSI levels still fell below 1.0 five times (28 percent) in the long-term Capacity Markets.

Demand

Phases 1 and 2

During the first and second intervals of 2004, PJM EDCs[14] and their affiliates maintained a large market share of load obligations in the PJM Capacity Market, averaging 76 percent (Figure 4-1), a reduction of 14 percentage points from 2003. The market share of PJM EDCs alone averaged 58 percent of the PJM load while the market share of their affiliates averaged 18 percent. The market shares for 2003 were 68 percent and 22 percent, respectively. The market share of LSEs not affiliated with any EDC was 6 percent and the market share of non-PJM EDCs and their affiliates averaged 18 percent. The corresponding values from 2003 were 4 percent and 6 percent, respectively.

During the first and second intervals of 2004, reliance on the PJM Capacity Credit Markets varied by sector. [15] As Table 4-3 shows, PJM EDCs relied on the Capacity Credit Markets for an average of -0.8 percent of their 2004 first and second interval unforced capacity obligations, while their affiliates relied on Capacity Credit Markets for an average of 1.5 percent of theirs. Affiliates of non-PJM EDCs obtained an average of -4.4 percent of their unforced capacity obligations from the

14 PJM electricity distribution companies (EDCs) refer to entities with a franchise service territory within the PJM boundaries. Non-PJM EDCs are electricity distribution companies whose franchise service territories lie outside of PJM boundaries.
15 The measure of a sector's reliance on the Capacity Credit Market is the sector's daily net Capacity Credit Market position divided by its capacity obligation. (This excludes self-supply and bilateral transactions.) Thus, a negative share means 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.

Capacity Credit Markets, while unaffiliated LSEs obtained an average of 15.2 percent of their capacity obligations from the Capacity Credit Markets. The large increase in reliance on the Capacity Credit Markets by unaffiliated LSEs in June 2004 was the result of the expiration of unit-specific bilateral contracts held by unaffiliated LSEs. In June these contracts were replaced by reliance on the Daily Capacity Credit Market. The reliance of unaffiliated LSEs on the Capacity Credit Markets subsequently decreased as these LSEs entered into bilateral capacity credit contracts during the rest of the second interval.

Figure 4-1 - PJM Capacity Market load obligation served (Percent): Calendar year 2004

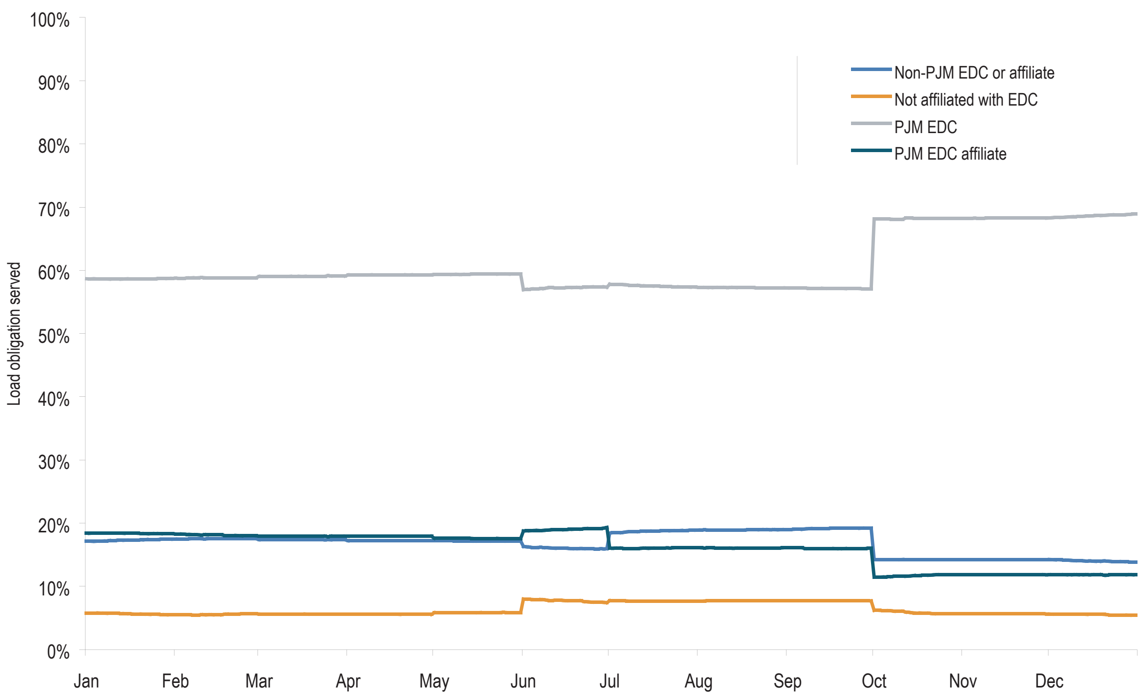


Table 4-3 - Load obligation served by PJM Capacity Market sectors: Calendar year 2004

	PJM EDC			PJM EDC Affiliate			Non-PJM EDC or Affiliate			Not Affiliated with EDC		
	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation
Jan	41,256	-786	-1.9%	12,928	-16	-0.1%	12,177	-75	-0.6%	3,982	876	22.0%
Feb	41,454	-769	-1.9%	12,772	199	1.6%	12,343	-208	-1.7%	3,916	777	19.9%
Mar	41,651	-826	-2.0%	12,656	610	4.8%	12,257	-268	-2.2%	3,962	484	12.2%
Apr	41,853	-351	-0.8%	12,656	529	4.2%	12,154	-607	-5.0%	3,943	429	10.9%
May	41,940	-337	-0.8%	12,427	309	2.5%	12,138	-186	-1.5%	4,133	214	5.2%
Jun	40,569	-381	-0.9%	13,467	-388	-2.9%	11,372	-541	-4.8%	5,481	1,310	23.9%
Jul	40,915	-178	-0.4%	11,412	158	1.4%	13,311	-1,063	-8.0%	5,481	1,083	19.8%
Aug	40,781	266	0.7%	11,444	188	1.6%	13,493	-1,115	-8.3%	5,503	661	12.0%
Sep	40,756	205	0.5%	11,416	85	0.7%	13,656	-857	-6.3%	5,511	567	10.3%
Oct	67,401	-190	-0.3%	11,556	-25	-0.2%	14,082	-669	-4.8%	5,807	884	15.2%
Nov	67,497	-36	-0.1%	11,720	-229	-2.0%	14,096	-455	-3.2%	5,589	720	12.9%
Dec	67,898	56	0.1%	11,717	-97	-0.8%	13,875	-669	-4.8%	5,482	711	13.0%
AVERAGE												
Calendar Year	47,867	-276	-0.6%	12,176	111	0.9%	12,917	-561	-4.3%	4,902	726	14.8%
Jan-May	41,632	-613	-1.5%	12,687	327	2.6%	12,213	-267	-2.2%	3,988	554	13.9%
Jan-Sep	41,242	-350	-0.8%	12,348	187	1.5%	12,548	-548	-4.4%	4,659	710	15.2%
Jun-Sep	40,757	-21	-0.1%	11,926	14	0.1%	12,965	-897	-6.9%	5,494	905	16.5%
Oct-Dec	67,599	-57	-0.1%	11,663	-116	-1.0%	14,017	-599	-4.3%	5,626	772	13.7%

Phase 3

During the third interval of 2004, PJM EDCs and their affiliates gained market share of PJM load obligations, averaging 80 percent. (See Figure 4-1.) The market share of PJM EDCs averaged 68 percent of the PJM load. The market share of the affiliates of PJM EDCs averaged 12 percent. The market share of entities not affiliated with an EDC was about 6 percent and the market share of non-PJM EDCs and their affiliates averaged about 14 percent.

During the third interval of 2004, reliance on the PJM Capacity Credit Markets varied by sector. As Table 4-3 shows, PJM EDCs relied on Capacity Credit Markets for an average of -0.1 percent of their 2004 third interval unforced capacity obligation while their affiliates relied on Capacity Credit Markets for an average of -1.0 percent of theirs. Affiliates of non-PJM EDCs obtained an average of -4.3 percent of their unforced capacity obligations from the Capacity Credit Markets, while unaffiliated LSEs obtained an average of 13.7 percent of their capacity obligations from the Capacity Credit Markets.

Supply and Demand

Phases 1 and 2

- **First Interval of 2004.** During the first interval of 2004, capacity resources exceeded capacity obligations in PJM on every day. The pool was long by an average of 2,359 MW. In other words, capacity resources exceeded obligation, on average, by 2,359 MW daily. 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.

  System net excess capacity can be determined using unforced capacity, obligation, the sum of members' excesses and the sum of members' deficiencies. Table 4-4 presents these data for the first interval of 2004.[16] 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.

  As shown in Figure 4-2, Figure 4-3 and Figure 4-4, capacity owners' external purchases (imports) of capacity resources were relatively flat through most of the first interval. This is consistent with the fact that the external daily forward energy price spread against PJM prices did not provide a consistent price signal over the interval.[17] These external transactions include approximately 1,200 MW of capacity resources that were exported to the NYISO throughout calendar year 2004.

- **Second Interval of 2004.** During the second interval of 2004, capacity resources exceeded capacity obligations in PJM on every day. The pool was long by an average of 695 MW. Table 4-5 presents these data for the second interval of 2004.[18] The primary reason for the reduction in system excess was that, as shown in Figure 4-2, Figure 4-3 and Figure 4-4, capacity owners decreased external purchases of capacity resources at the beginning of the second interval (June).

16 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.
17 The PJM price in Figure 4-3 is the firm, daily forward on-peak PJM Western Hub energy price, while the external price is the firm, daily forward on-peak price for Cinergy (converted to dollars per MW-day).
18 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.

Table 4-4 - PJM capacity summary (MW): January through May 2004

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	78,025	451	77,260	78,751
Unforced Capacity	72,878	393	72,210	73,525
Obligation	70,519	110	70,274	70,686
Sum of Excess	2,365	486	1,588	3,127
Sum of Deficiency	6	16	0	49
Net Excess	2,359	479	1,588	3,122
Imports	3,770	183	3,523	4,092
Exports	1,318	57	1,078	1,473
Net Exchange	2,453	203	2,050	2,814
Unit-Specific Transactions	59,607	24	59,521	59,629
Capacity Credit Transactions	69,495	524	68,657	70,412
Internal Bilateral Transactions	129,101	513	128,267	130,022
Daily Capacity Credits	994	245	640	1,549
Monthly Capacity Credits	1,199	135	1,018	1,363
Multimonthly Capacity Credits	2,619	391	2,065	3,028
All Capacity Credits	4,812	283	4,395	5,258
ALM Credits	1,207	0	1,207	1,207

Table 4-5 - PJM capacity summary (MW): June through September 2004

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	77,234	403	76,485	77,640
Unforced Capacity	71,838	379	71,177	72,231
Obligation	71,142	167	70,852	71,409
Sum of Excess	695	298	292	1,117
Sum of Deficiency	0	0	0	3
Net Excess	695	298	292	1,117
Imports	2,335	257	1,922	2,611
Exports	1,432	71	1,326	1,566
Net Exchange	903	269	482	1,171
Unit-Specific Transactions	11,813	57	11,747	11,879
Capacity Credit Transactions	60,452	1,442	57,249	61,760
Internal Bilateral Transactions	72,265	1,490	68,996	73,639
Daily Capacity Credits	1,203	240	731	1,971
Monthly Capacity Credits	971	118	828	1,152
Multimonthly Capacity Credits	3,325	72	3,213	3,388
All Capacity Credits	5,499	259	5,044	6,336
ALM Credits	927	82	880	1,072

Figure 4-2 - Capacity obligations to the PJM Capacity Market: Calendar year 2004

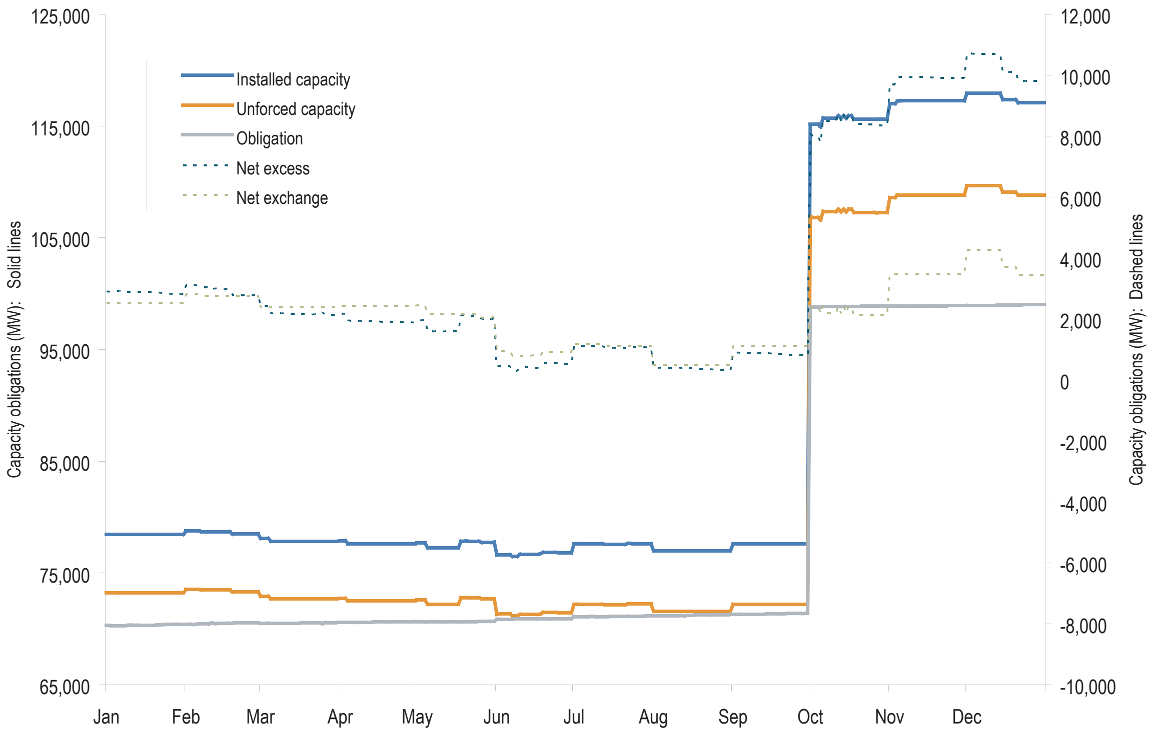
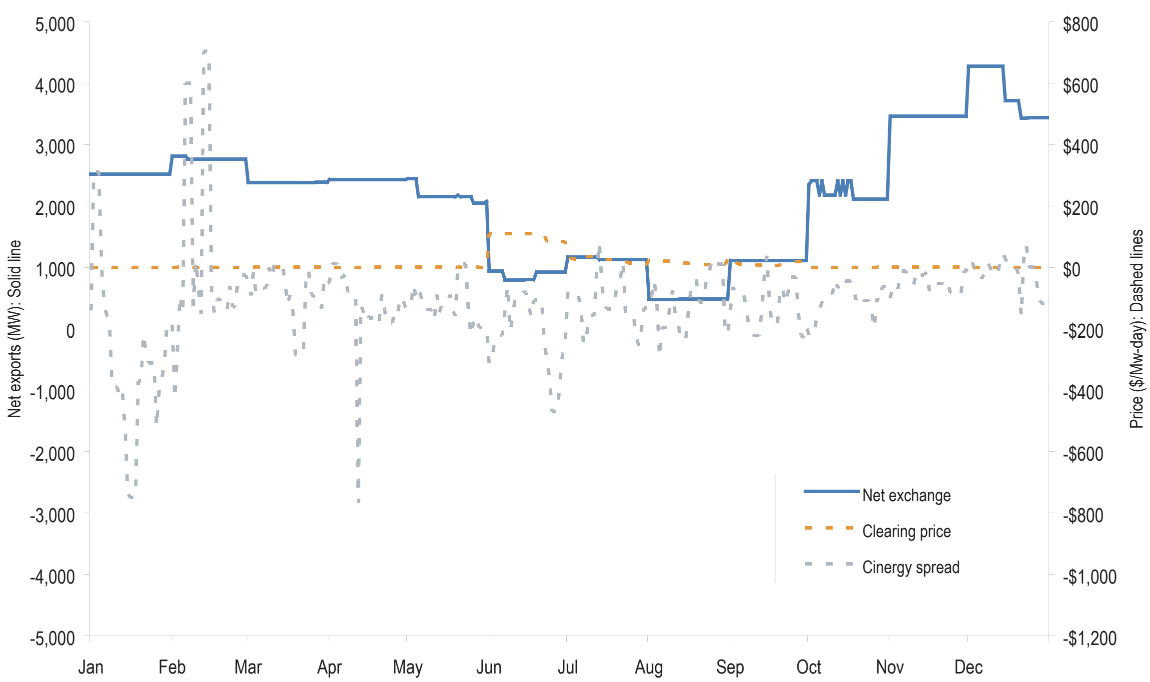


Figure 4-3 - PJM daily capacity credit market-clearing price and Cinergy spread vs. net exchange: Calendar year 2004



Phase 3

In the third interval of 2004, capacity resources exceeded capacity obligations in PJM every day. The pool was long by an average of 9,515 MW. Table 4-6 presents these data for the third interval of 2004.[19] The large increase in the average for all values in the tables was caused by the integration of the AEP and DAY Control Zones. Average net excess increased by 8,820 MW, or 1,269 percent, over the second interval. Average obligation increased by 27,764 MW, or 39.0 percent, over the second interval.

Table 4-6 - PJM capacity summary (MW): October through December 2004

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	116,770	894	114,916	117,926
Unforced Capacity	108,422	908	106,592	109,645
Obligation	98,906	56	98,809	99,003
Sum of Excess	9,515	865	7,783	10,707
Sum of Deficiency	0	0	0	0
Net Excess	9,515	865	7,783	10,707
Imports	6,392	876	5,219	7,355
Exports	3,211	304	2,872	3,923
Net Exchange	3,181	748	2,118	4,278
Unit-Specific Transactions	12,597	23	12,581	12,668
Capacity Credit Transactions	64,571	421	64,114	65,330
Internal Bilateral Transactions	77,168	435	76,695	77,957
Daily Capacity Credits	986	241	671	1,512
Monthly Capacity Credits	773	94	664	893
Multimonthly Capacity Credits	3,002	121	2,833	3,088
All Capacity Credits	4,761	195	4,517	5,238
ALM Credits	1,662	8	1,653	1,669

External Capacity Transactions

Phases 1 and 2

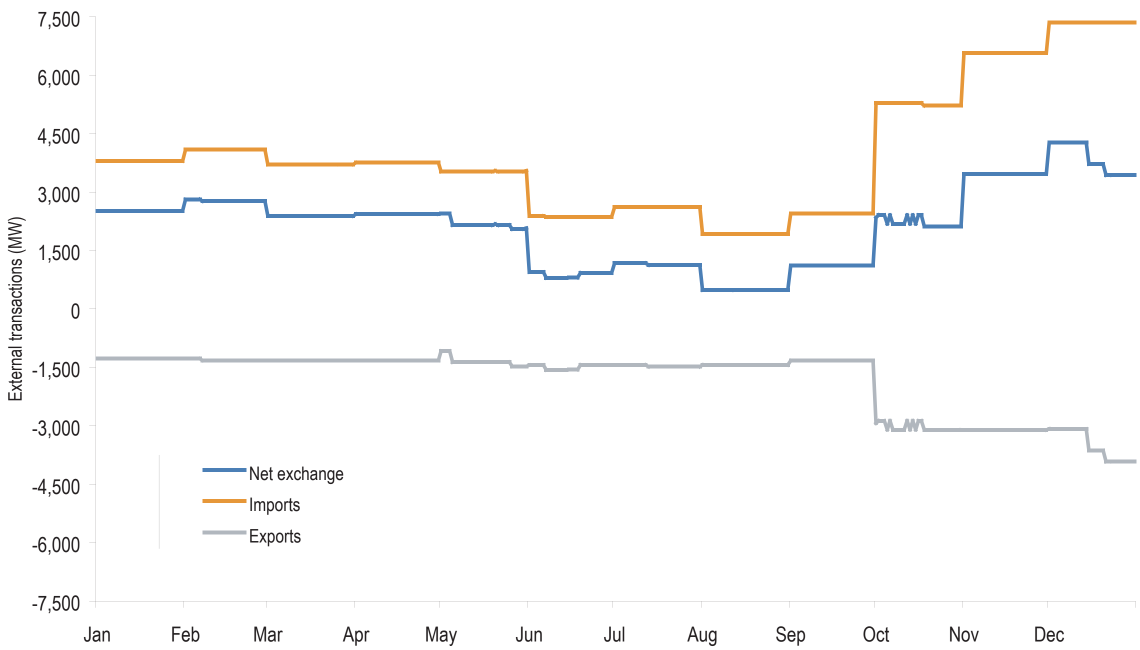
PJM capacity resources may be traded bilaterally within and outside of PJM. Figure 4-4 presents PJM external bilateral capacity transaction data for 2004. (Table 4-4, Table, 4-5 and Table 4-6 also include data on imports and exports.)

During the first interval, an average of 3,770 MW of capacity resources was imported into the PJM Capacity Market, while an average of 1,318 MW was exported. The result was an average net exchange of 2,453 MW of capacity resources. The maximum exports were 1,473 MW, while the maximum imports were 4,092 MW.

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

During the second interval, an average of 2,335 MW of capacity resources was imported into PJM while an average of 1,432 MW was exported, resulting in an average net exchange of 903 MW of capacity resources. The maximum exports were 1,566 MW, while the maximum imports were 2,611 MW. Imports decreased by about 1,200 MW on June 1, 2004 (Figure 4-4); this was the main reason for the reduction in net excess on the same date.

Figure 4-4 - External PJM Capacity Market transactions: Calendar year 2004



Phase 3

During the third interval, an average of 6,392 MW of capacity resources was imported into the PJM Capacity Market while an average of 3,211 MW was exported, resulting in an average net exchange of 3,181 MW of capacity resources. The maximum level of exports was 3,923 MW, while the maximum level of imports was 7,355 MW. Imports increased by about 2,800 MW as Phase 3 began (Figure 4-4) and exports increased by 1,400 MW upon the integration of the AEP and DAY Control Zones. These external transactions include approximately 1,300 MW of capacity resources that were exported to the NYISO throughout calendar year 2004.

Internal Bilateral Transactions

Phases 1 and 2

During the first interval of 2004, internal, unit-specific transactions for the PJM Capacity Market averaged 59,607 MW. (See Figure 4-5.) Internal capacity credit transactions in the first interval of 2004 averaged 69,495 MW. Internal, unit-specific and capacity credit bilateral transactions may be traded between parties multiple times with the result that transaction volume can exceed obligation.

During the second interval of 2004, internal, unit-specific transactions for the PJM Capacity Market averaged 11,813 MW, a decline of 80.2 percent from the first interval. (See Figure 4-5.) As of June 1, 2004, unit-specific capacity transactions were no longer required in order to qualify for an FTR.[20] Internal capacity credit transactions in the second interval of 2004 averaged 60,452 MW, which represents a 13.0 percent decrease from the first interval.

Phase 3

Internal, unit-specific transactions for the PJM Capacity Market during the third interval of 2004 averaged 12,597 MW, a 6.6 percent increase over the second interval of 2004. (See Figure 4-5 and Table 4-6.) Internal capacity credit transactions, in the third interval of 2004 averaged 64,571 MW, an increase of 4,119 MW or 6.8 percent when compared to the second interval of 2004.

Active Load Management (ALM) Credits

Phases 1 and 2

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 the first interval of 2004, ALM credits in the PJM Capacity Market averaged 1,207 MW, down approximately 7 percent from 1,292 MW in 2003. (See Table 4-4.) ALM participation declined for a number of reasons, including the shifting of participants to other demand-side response (DSR) programs.

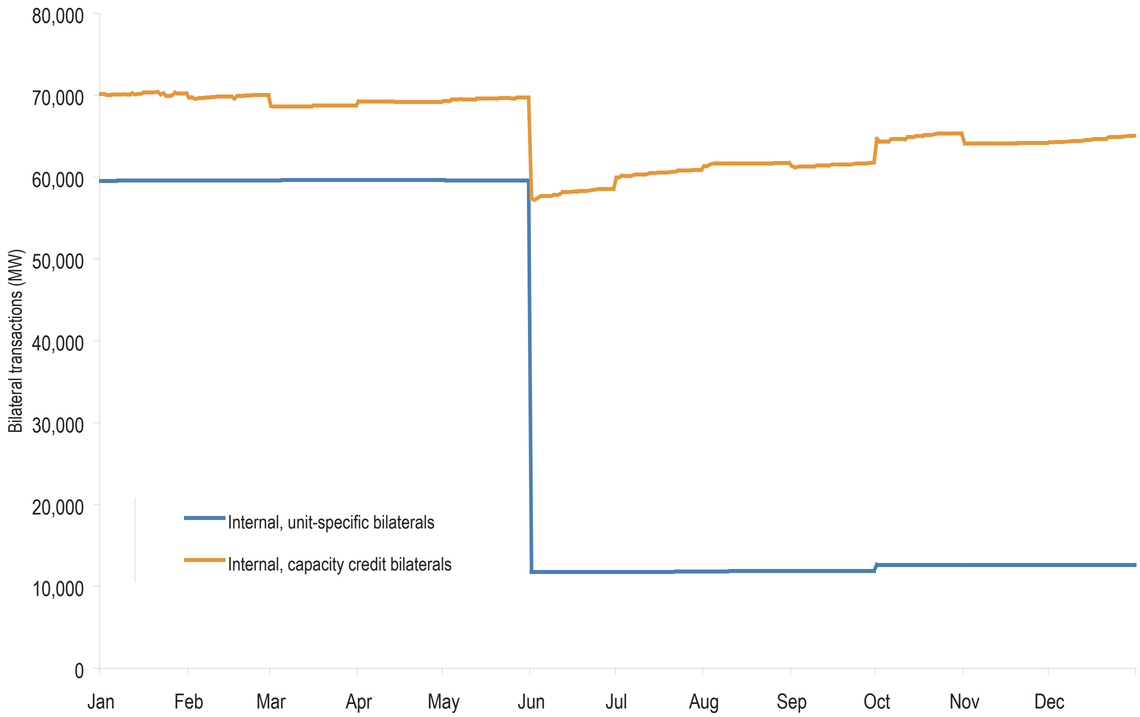
During the second interval of 2004, ALM credits in the PJM Capacity Market averaged 927 MW, down approximately 23 percent from 1,207 MW during the second interval of 2003. (See Table 4-5.)

Phase 3

ALM credits in PJM averaged 1,662 MW in the third interval of 2004, an increase of approximately 79.3 percent from 927 MW in the second interval of 2004. (See Table 4-6.)

20 See Section 7, "Financial Transmission and Auction Revenue Rights," for a more complete explanation of this rule change.

Figure 4-5 - Internal bilateral PJM Capacity Market transactions: Calendar year 2004



Market Performance in the PJM Capacity Markets

Capacity Credit Market Volumes

Phases 1 and 2

During the first interval of 2004, PJM operated Daily, Monthly and Multimonthly Capacity Credit Markets. Table 4-4 shows the Daily Capacity Credit Market averaged 994 MW of transactions, or about 1.4 percent of the average capacity obligations for the period. Trading in the PJM Daily Capacity Credit Market increased by 65.1 percent compared to activity in the market in the first interval of 2003. The average volume for all capacity credits during the first interval of 2004 was 4,812 MW and the volume for the corresponding interval in 2003 was 3,779 MW.

Table 4-5 shows that during the second interval, the PJM Daily Capacity Credit Market averaged 1,203 MW of transactions, or about 1.7 percent of the average capacity obligation for the period. Trading in the PJM Daily Capacity Credit Market increased, by an average of 1,720 MW, or 62.9 percent, compared to what had been experienced during the same period of 2003.

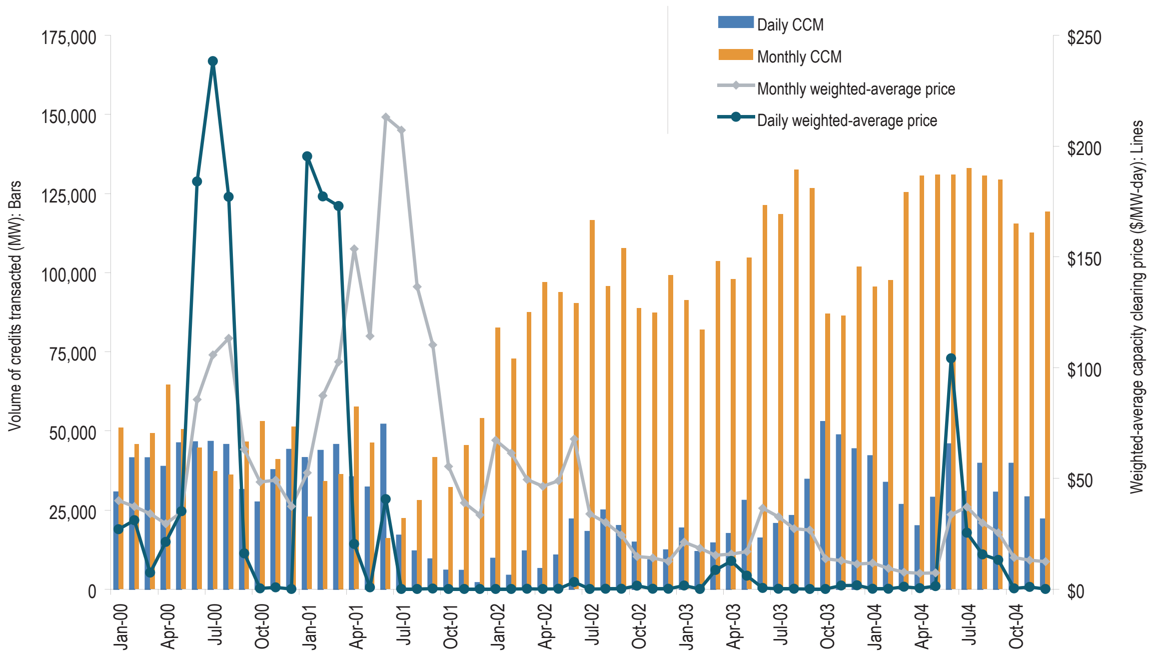
Phase 3

Table 4-6 shows that during the third interval, the PJM Daily Capacity Credit Market averaged 986 MW of transactions, or about 1.0 percent of the average capacity obligation for the period. Trading in the PJM Daily Capacity Credit Market decreased in the last interval of 2004, with average daily volume declining by 217 MW or 18.0 percent.

Capacity Credit Market Volumes: Calendar Years 1999 to 2004

Figure 4-6 shows prices and volumes in PJM's Daily and longer term Capacity Credit Markets from 2000 through 2004. Since the interval system was introduced in June 2001, overall volume in the Monthly and Multimonthly Capacity Credit Markets has increased and prices in both the daily and longer term markets have declined and remained relatively stable with the exception of the second interval of 2004. Although daily volume has risen to pre-June 2001 levels, capacity obligations have increased by more than 25 percent. The share of load obligation traded in the PJM Daily Capacity Market has declined since the introduction of Interval Markets, 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 1.6 percent in the last two intervals of 2003. In comparison, average daily capacity credit market volume in 2004 increased to 1,062 MW from 907 MW in 2003, but as a percent of obligation, 2004 volume remained approximately the same at 1.4 percent of obligation. Monthly and multimonthly capacity market volume increased from 3.0 percent of obligation in 2000 to 5.2 percent of average obligation in the last two intervals of 2003. In comparison, average monthly and multimonthly capacity credit market volume in 2004 increased to 3,966 MW from 3,435 MW in 2003, but 2004 volume as a percent of obligation declined slightly to 5.1 percent from 5.2 percent in 2003. With the integration of the AEP and DAY Control Zones, by virtue of their participation, total volume traded has increased. Nonetheless, because of the new participants' reliance on their own resources, volume as a percent of obligation has declined once again, with values approaching 1 percent for the Daily Capacity Credit Market and 4 percent for the Monthly and Multimonthly Capacity Credit Markets since October 2004.

Figure 4-6 - PJM Daily and Monthly Capacity Credit Market (CCM) performance: Calendar years 2000 to 2004



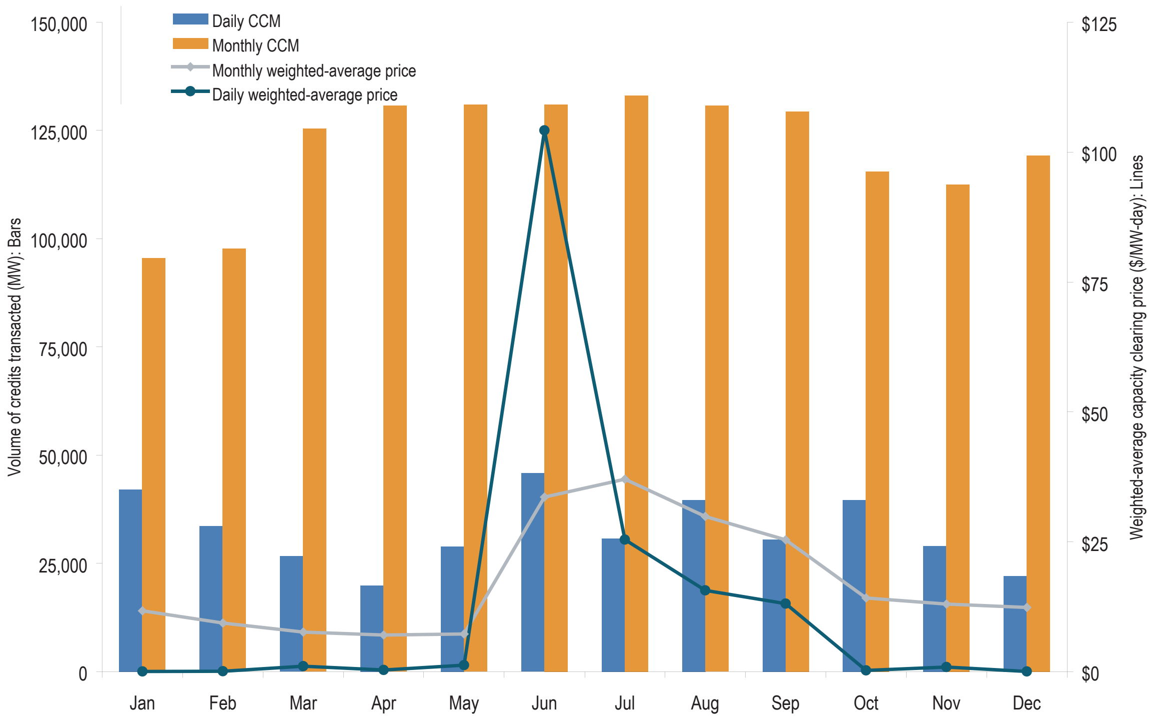
Capacity Credit Market Prices

Phases 1 and 2

Table 4-7 and Figure 4-7 show prices and volumes in the first interval for PJM's Daily and longer term Capacity Credit Markets. The volume-weighted average price for the first interval of 2004 was $0.51 per MW-day in the Daily Capacity Credit Market and $8.38 per MW-day in the Monthly and Multimonthly Capacity Credit Markets. The volume-weighted average price for all Capacity Credit Markets was $6.75 per MW-day.[21] Prices in the Daily Capacity Credit Market were relatively constant during the first interval of the year and declined slightly in the Monthly and Multimonthly Capacity Credit Markets. (See Figure 4-7.) Prices in the Monthly and Multimonthly Markets during the first interval of 2004 were 51.7 percent lower than during the same period of 2003. Prices in the Daily Capacity Credit Market were 91.5 percent lower for the period.

21 Graph and the average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.

Figure 4-7 - PJM Daily and Monthly Capacity Credit Market (CCM) performance: Calendar year 2004



The volume-weighted average price for the second interval of 2004 was $31.53 per MW-day in the PJM Monthly and Multimonthly Capacity Credit Markets and $44.79 per MW-day in the Daily Capacity Credit Market. The volume-weighted average price for all Capacity Credit Markets was $34.43 per MW-day.[22] Table 4-7 and Figure 4-7 show price and volume in both PJM's Daily and longer term Capacity Credit Markets. Prices increased in this interval because the market was tighter. Net excess in the second interval declined 71 percent from an average 2,359 MW in the first interval to 695 MW. (See Table 4-4 and Table 4-5.)

22 Graph and the average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.

Table 4-7 - PJM Capacity Credit Markets: Calendar year 2004

	Average Daily Volume (MW)	Monthly and Multimonthly Volume (MW)	Combined Volume (MW)	Daily Weighted-Average Price ($ per MW-day)	Monthly and Multimonthly Weighted-Average Price ($ per MW-day)	Combined Weighted-Average Price ($ per MW-day)
Jan	1,357	3,083	4,440	$0.05	$11.72	$8.16
Feb	1,159	3,368	4,527	$0.10	$9.35	$6.98
Mar	860	4,045	4,905	$1.06	$7.61	$6.46
Apr	664	4,357	5,021	$0.33	$7.07	$6.18
May	932	4,223	5,155	$1.25	$7.26	$6.17
Jun	1,527	4,366	5,893	$104.15	$33.60	$51.89
Jul	993	4,293	5,287	$25.41	$37.06	$34.87
Aug	1,279	4,216	5,495	$15.64	$29.88	$26.57
Sep	1,017	4,313	5,330	$13.08	$25.39	$23.04
Oct	1,279	3,726	5,005	$0.24	$14.19	$10.63
Nov	967	3,752	4,720	$0.91	$13.00	$10.52
Dec	712	3,846	4,558	$0.03	$12.36	$10.43
			Average			
Calendar Year	1,062	3,966	5,028	$17.21	$17.88	$17.74
Jan-May	994	3,817	4,812	$0.51	$8.38	$6.75
Jun-Sep	1,203	4,296	5,499	$44.79	$31.53	$34.43
Jan-Sep	1,087	4,031	5,118	$22.32	$19.36	$19.99
Oct-Dec	986	3,775	4,761	$0.40	$13.17	$10.53

Phase 3

The volume-weighted average price for the third interval of 2004, as shown in Table 4-7, was $13.17 per MW-day in the Monthly and Multimonthly Capacity Credit Markets and $0.40 per MW-day in the Daily Capacity Credit Market. The volume-weighted average price for all Capacity Credit Markets was $10.53 per MW-day.[23] Prices in the PJM Capacity Credit Market approached pre-June 2004 levels in the last interval of the calendar year. (See Figure 4-7.) Prices in the PJM Capacity Credit Markets in the third interval of 2004 were somewhat less than those in the third interval of 2003. In the third interval of 2003 prices averaged $12.53 per MW-day in the Monthly and Multimonthly Capacity Credit Markets, $1.03 per MW-day in the Daily Capacity Credit Market and $16.03 per MW-day for the volume-weighted average price for all Capacity Credit Markets.

Capacity Credit Market Prices: Calendar Years 1999 to 2004

The volume-weighted average price for all Capacity Credit Markets was $52.86 per MW-day in 1999, $60.55 in 2000, $95.34 in 2001, $33.40 in 2002, $17.51 in 2003 and $17.74 in 2004. The volume-weighted average price for the Monthly and Multimonthly Capacity Credit Markets was $70.66 per MW-day in 1999, $53.16 in 2000, $100.43 in 2001, $38.21 in 2002, $21.57 in 2003 and $17.88 in 2004, while the price in the Daily Capacity Credit Market averaged $3.63 per MW-day in 1999, $69.39 in 2000, $87.98 in 2001, $0.59 in 2002, $2.14 in 2003 and $17.21 in 2004.

Daily Capacity Credit Market – Summer 2004

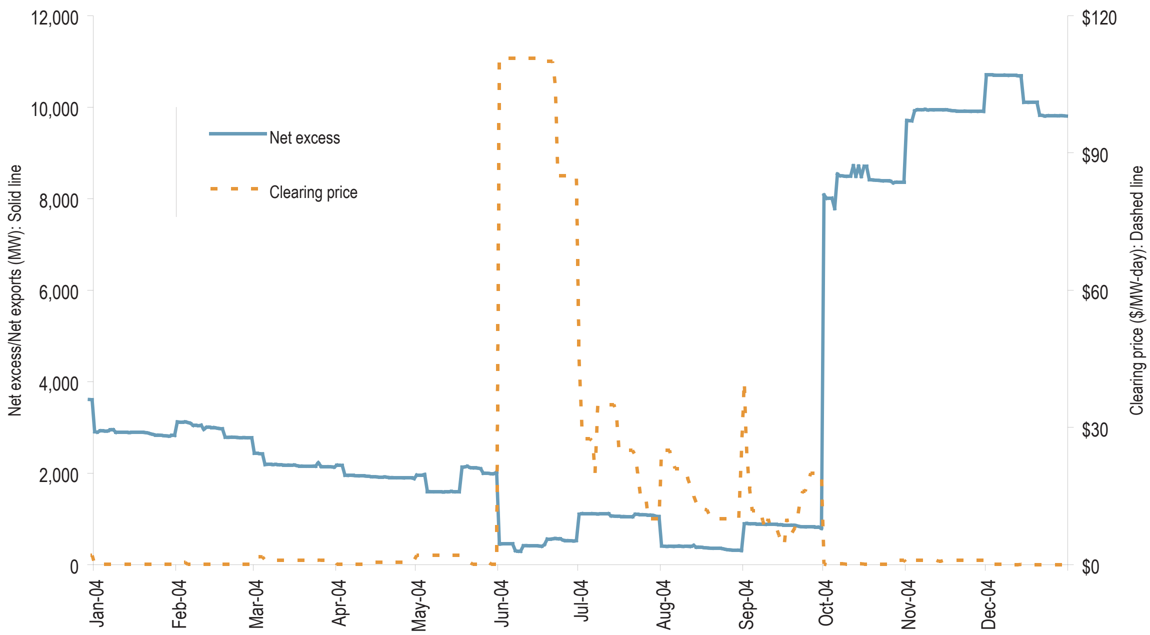
Prices in the PJM Daily Capacity Credit Market increased sharply on June 1, 2004, rising to $110.61 per MW-day from $0.05 per MW-day on May 31. The price increase persisted for about a month. (See Figure 4-8.) The price increase was the result of competitive market fundamentals, including an increase in demand in the Daily Markets and a decrease in supply available to the Daily Markets. The overall average price for the summer interval was $44.79, an increase of $44.66 over the $0.13 summer interval price in 2003. The overall average price in the Daily Markets for 2004 was $17.21, an increase of $15.07 over the 2003 average daily market price of $2.14.

Table 4-8 - The PJM Capacity Market's summer parameters: July to September 2004

Capacity Market Parameters Summer Interval 2004	June 2004			July 2004			August 2004			September 2004		
	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum
Average Daily CCM Demand (MW)	1,532	2,124	1,368	993	1,178	894	1,289	1,413	1,246	1,029	1,087	974
Offered Supply (MW)	1,864	2,228	1,717	1,802	2,021	1,708	1,524	1,586	1,257	1,577	1,838	731
Net Excess (MW)	462	571	292	1,086	1,117	1,046	370	420	305	861	900	791
Capacity Not Offered (MW)	125	427	67	277	401	238	125	407	68	301	890	114

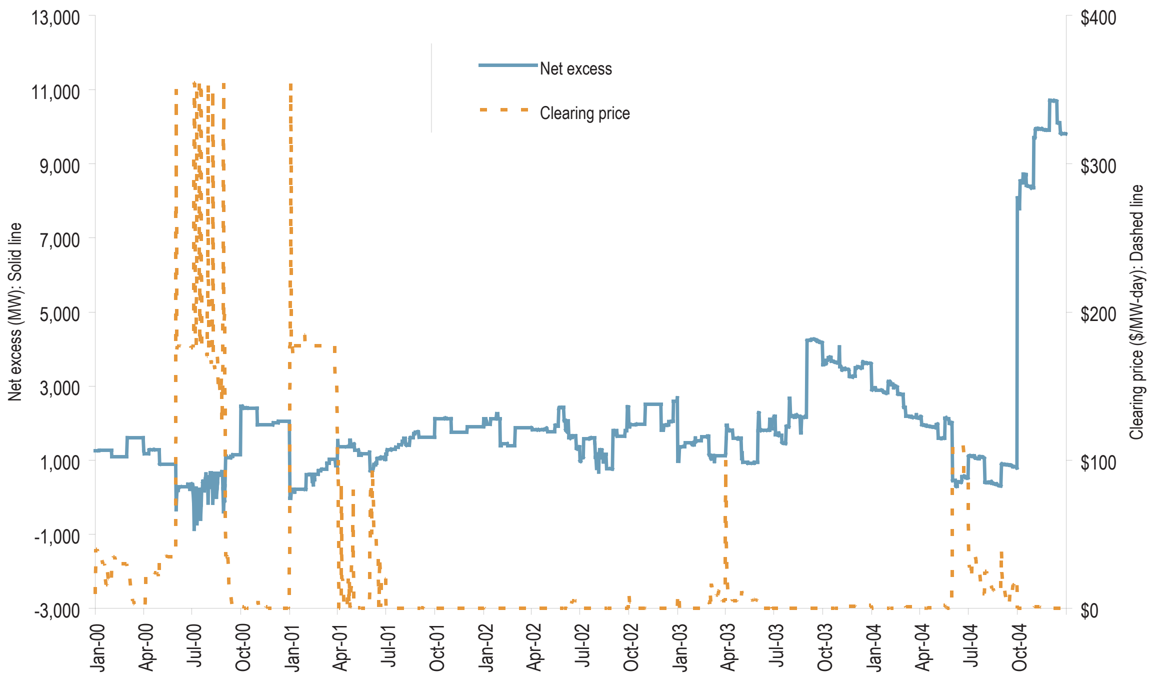
23 Graph and average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.

Figure 4-8 - The PJM Capacity Market's net excess vs. capacity credit market-clearing prices: Calendar year 2004



Daily capacity market prices generally increase when the market gets tighter, as measured by the difference between available supply and demand, termed net excess. More precisely, daily capacity market prices generally increase when the net excess is below 1,000 MW. Figure 4-9 shows the relationship between net excess and the daily capacity credit market-clearing prices from January 2000 through December 2004.

Figure 4-9 - The PJM Capacity Market's net excess vs. capacity credit market-clearing prices: January 2000 to December 2004



On June 1, 2004, the net excess decreased to 449 MW from 2,017 MW on May 31, as shown in Figure 4-9. The decrease in net excess was caused by a decrease of more than 1,100 MW in imports; an increase of approximately 200 MW in obligation, an approximate 325 MW reduction in unforced capacity caused by a change in the 12-month rolling EFORd and other changes such as capacity retirements, adjustments and additions.

The reliance of entities unaffiliated with EDCs on the Capacity Credit Markets increased from 5.2 percent in May to 23.9 percent in June. (See Table 4-3.) More significantly, market participants' overall reliance on the Daily Capacity Credit Markets increased from 1.5 percent on May 31, 2004, to 2.8 percent on June 1, 2004. The reliance of entities unaffiliated with EDCs on the Capacity Credit Markets increased from 5.5 percent on May 31, 2004, to 28.9 percent on June 1, 2004. In addition to these increases, this sector also gained market share at the beginning of the planning period. Figure 4-1 shows that their market share of obligation increased from 5.9 percent on May 31, 2004, to 8.0 percent on June 1, 2004.

Table 4-9 - The PJM Capacity Market's parameters: Comparison of 2004 winter vs. summer interval

	2004 Winter Interval			2004 Summer Interval			Winter Summer Difference	
	Average	Maximum	Minimum	Average	Maximum	Minimum	Average Change	Percent Change
Average Daily CCM Demand (MW)	994	1,549	640	1,210	2,124	894	215	21.7%
Offered Supply (MW)	2,599	2,291	731	1,691	2,228	731	-908	-34.9%
Net Excess (MW)	2,359	2,017	292	695	1,117	292	-1,664	-70.5%
Capacity Not Offered (MW)	754	890	67	207	890	67	-547	-72.5%

A comparison of the second (summer) interval to the first (winter) interval also illustrates the changed fundamentals. Demand in the Daily Capacity Credit Market increased to 1,210 MW in the second interval, a 21.7 percent increase from the first interval average of 994 MW. (See Table 4-9.) Net excess in the second interval decreased by 1,664 MW, or 70.5 percent, from an average 2,359 MW in the first interval to an average of 695 MW in the second interval. Average offered supply decreased by 34.9 percent in the second interval to 1,691 MW from 2,599 MW in the first interval.

A decrease in net excess may lead to higher prices because of factors related to both the demand side and the supply side of the Daily Capacity Market. While the aggregate demand for capacity is fixed, market participants have the flexibility to choose whether to self-supply, to purchase bilaterally, to purchase in the variety of monthly and multimonthly auctions or to purchase in the Daily Capacity Market. The actual demand for capacity can be quite elastic, but varies by capacity auction. Demand in the Daily Capacity Market tends to be the least elastic of all the market options because a consequence of failing to cover one's obligation in the Daily Market is incurring a capacity deficiency charge. Participants also have until the end of the day of any daily auction to procure capacity bilaterally before becoming short for the operating day and being obligated to pay a capacity deficiency charge. Thus, as more market participants shift to reliance on the Daily Capacity Market, the more inelastic overall demand for capacity becomes and the more likely is price volatility in the Daily Capacity Market.

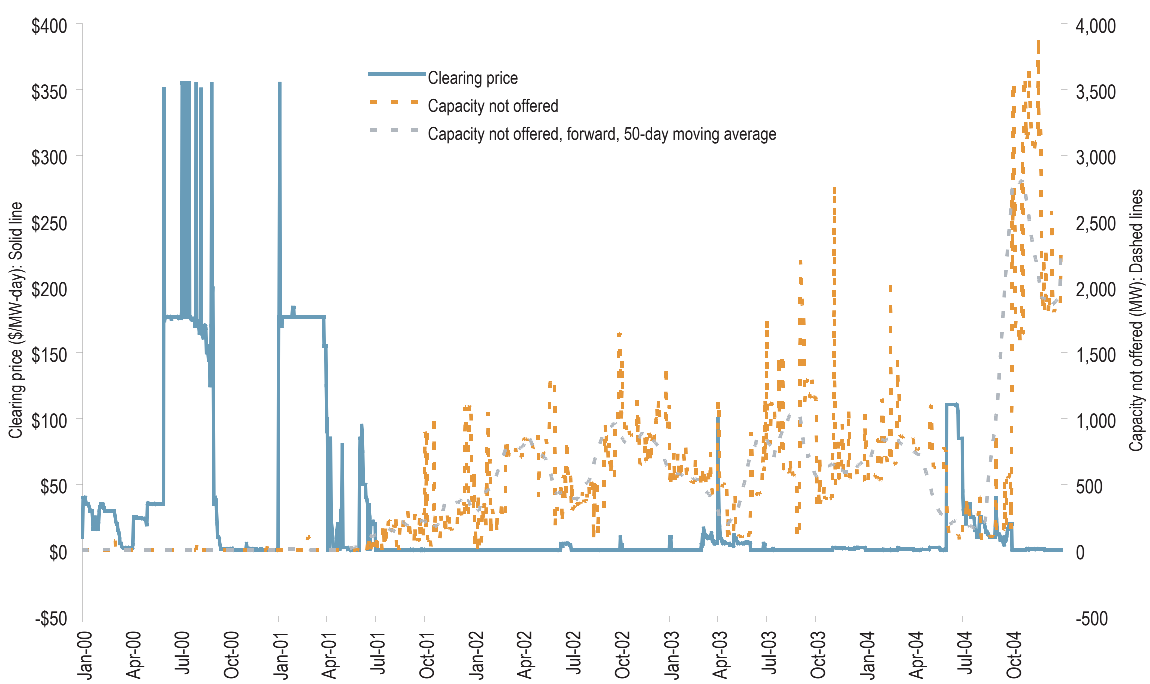
Another reason that a decrease in net excess leads to higher prices is the shape of the supply curve. The supply curve for capacity is upwardly sloped. As the level of relatively inelastic demand increases, it intersects the supply curve at higher prices. The incremental cost of capacity and thus the competitive price of capacity is the net avoidable cost of capacity. The net avoidable cost of capacity is equal to the annual cost to maintain a unit as a capacity resource, less net revenues received from other markets. In other words, it would be rational to retire a unit if it does not recover its net avoidable costs from a combination of the Energy, Ancillary Service and Capacity Markets. The overall supply curve for capacity has baseload units as the lowest cost sources of supply as energy market revenues typically offset all of the avoidable costs and has intermediate units as the next most expensive sources of capacity as energy and ancillary service markets revenues offset a significant portion of avoidable costs, depending on unit characteristics. Older combustion turbines tend to be at the top of the overall capacity market supply curve as some of these units have poor heat rates and high annual maintenance costs. These units operate only infrequently, especially in years with relatively mild temperatures like 2004, and, therefore, earn very little from the Energy and Ancillary Service Markets. As a result these units have, in some cases, very high net avoidable costs.

Reflecting both demand-side and supply-side factors, market participants increased both bid and offer prices commencing with the June 1, 2004, Daily Capacity Credit Market. The average bid price increased from $239.36 per MW-day on May 31, 2004, to $354.01 per MW-day on June 1, 2004. The average offer price increased from $2.30 per MW-day on May 31, 2004, to $67.37 per MW-day on June 1, 2004.

These fundamental supply and demand factors contributed significantly to the increase in the daily capacity credit market-clearing price. The daily capacity market prices reflected a reasonably competitive outcome given the underlying fundamentals. Offer prices, even the relatively high clearing offer prices, were in general based on avoidable costs of the relevant units. While there was the clear potential for the exercise of market power in these markets based on both the market structure and supply-demand conditions, the evidence is that the outcomes generally reflected competitive offers. In this case, outcomes reflected competitive offers not because the market structure constrained participants to behave in a competitive manner, but because key market participants chose to behave in a competitive manner.

Nonetheless, one cause for concern is that not all available capacity was offered into the market. Mandatory participation requirements in the Daily Capacity Credit Market were eliminated effective July 1, 2001.

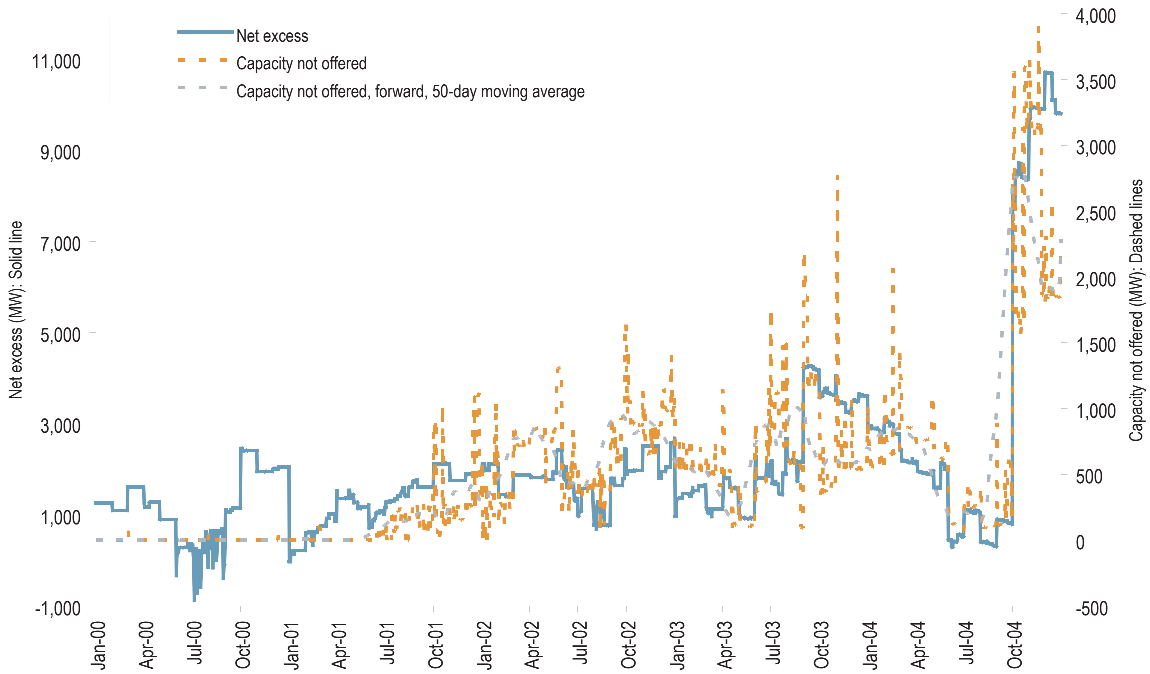
Figure 4-10 - The PJM Capacity Market's clearing price vs. capacity not offered: January 2000 to October 2004



As Figure 4-10 shows, since July 1, 2001, not all capacity has been offered into the Capacity Credit Markets on a daily basis. However, the level of capacity not offered is inversely related to prices and directly related to net excess (see Figure 4-11) as capacity owners offer more of their available capacity to the market when prices are high and net excess is low and offer less when prices are low and net excess is high. Consistent with this general pattern, capacity not offered decreased by 72.5 percent to 207 MW in the second interval from 754 MW in the first interval. As a general matter, the withholding of capacity has not had an impact on prices. The withholding of capacity did not have a significant impact on prices during June.

On July 1, 2004, additional unforced capacity became available to the market as new capacity resources entered. Net excess increased from 527 MW to 1,101 MW. In addition, market participants who had purchased capacity in the Daily Market in June began to enter into capacity credit bilateral transactions as shown in Figure 4-5. The capacity-clearing price trended downward for the remainder of the summer.

Figure 4-11 - The PJM Capacity Market's net excess vs. capacity not offered: Calendar years 2000 to 2004

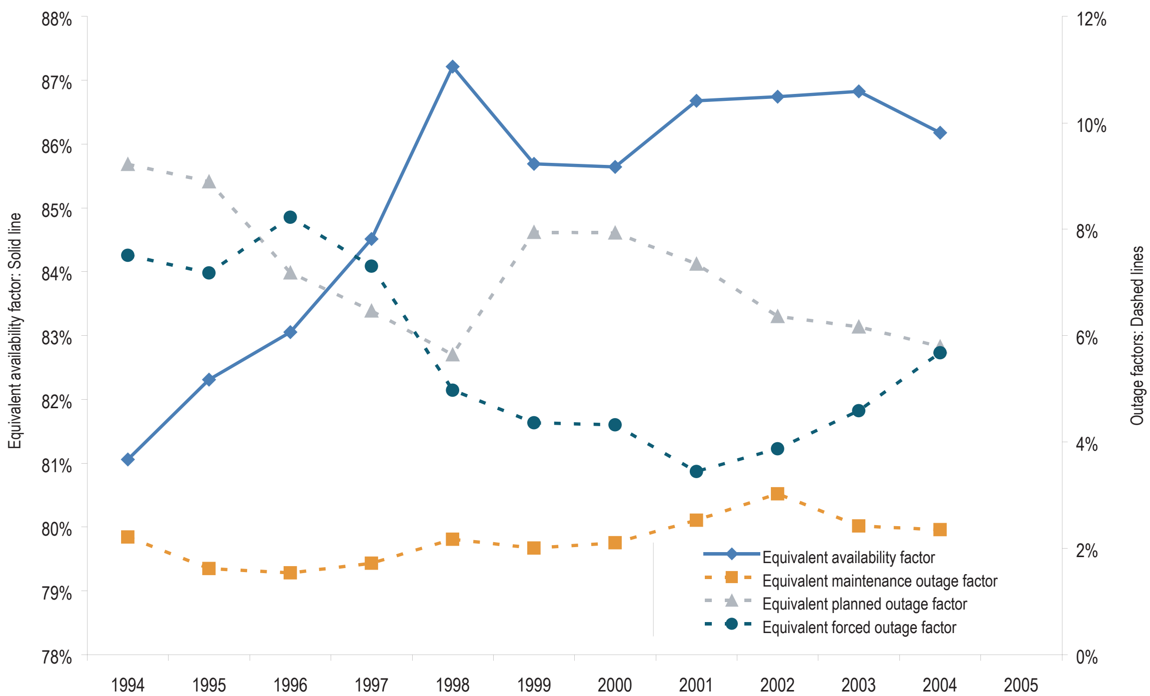


The conclusion is that the increase in capacity credit market-clearing prices during June 2004 and their subsequent reduction were the result of market fundamentals, including an increased reliance on Daily Capacity Markets and a decrease in available capacity. Although the market structure made the exercise of market power possible, market participants chose to behave in a competitive manner and the market outcomes reflected that behavior.

Generator Performance

Certain outage statistics are calculated by reference to total hours in the year rather than statistical probability. Figure 4-12 shows these performance measures for all PJM units, excluding those in the ComEd Control Zone and the more recently integrated AEP and DAY Control Zones. The equivalent availability factor equals the proportion of hours in a year that a unit is available to generate at full capacity. The sum of the equivalent availability factor, the equivalent maintenance outage factor, the equivalent planned outage factor and equivalent forced outage factor equals 100 percent. The increase in the equivalent forced outage factor from 2003 to 2004 corresponded with a decrease in the equivalent availability factor. Equivalent planned and maintenance outage factors did not change significantly in 2004 from 2003. The PJM aggregate equivalent availability factor was 86.8 percent in 2003 and 86.2 percent in 2004.

Figure 4-12 - PJM equivalent outage and availability factors: Calendar years 1994 to 2004



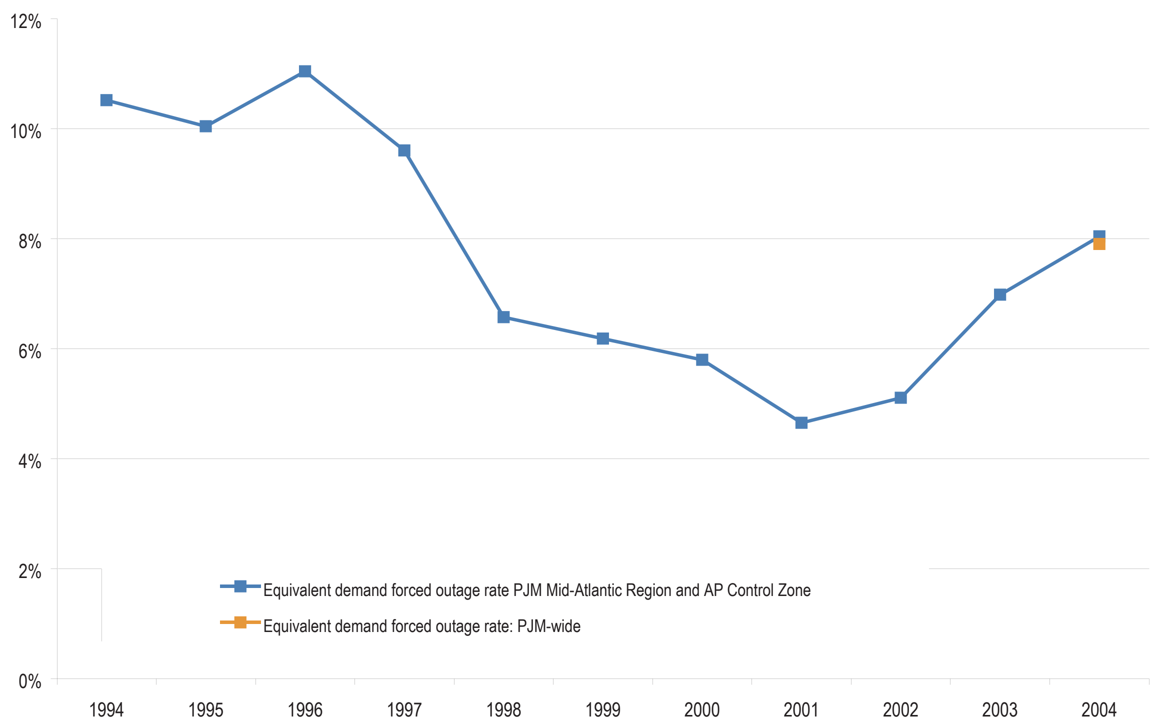
EFORd is a statistical measure of the probability that a unit will fail, either partially or totally, to perform when it is needed. Unforced capacity for any individual generating unit is equal to one minus the EFORd multiplied by the generating unit's net dependable summer capability. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available from a unit is inversely related to the forced outage rate. EFORd calculations use historical data, including equivalent[24] forced outage hours, service hours, average

24 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.
25 See PJM Manual M22, "Generator Resource Performance Indices, Revision 13" (May 1, 2004), p. 7.
26 The 2004 PJM availability factors and forced outage rates are calculated for the AP Control Zone of the PJM Western Region and the PJM Mid-Atlantic Region combined. The equivalent outage and availability factors figure, Figure 0-12 and the EFORd figure, Figure 0-13, are comparable to corresponding figures in the 2003 State of the Market Report (March 10, 2004), pp. 132 and 133.

forced outage duration, average run time, average time between unit starts, available hours and period hours.[25] Between 1996 and 2001, the average PJM[26] EFORd trended downward, reaching 4.8 percent in 2001 and then increasing to 5.2 percent in 2002, 7.0 percent in 2003 and 8.0 percent in 2004. The increase in EFORd of 1.0 percent from 2003 to 2004 was the result of increased forced outage rates across most unit types. Fossil steam units' EFORd contributed 0.5 percentage points, combustion turbine units' EFORd contributed 0.1 percentage points, hydroelectric units' EFORd contributed 0.1 percentage points, combined-cycle units' contributed 0.1 percentage points and nuclear units contributed 0.2 percentage points to the overall increase of 1.0 percentage point. Of the 672 generating units in the EFORd analysis, 336 units (about 50 percent) had increased EFORds, 250 units had decreased EFORds and the remaining 86 units had unchanged EFORds. In the absence of offsetting improvements in EFORd by 250 units, the EFORd would have increased by 3.6 percentage points to 10.6 percent. The 250 units with lower forced outage rates reduced the EFORd by 2.6 percentage points, to the observed 8.0 percent EFORd.

Figure 4-13 shows the average EFORd since 1994 for all units in the PJM Mid-Atlantic Region and AP Control Zone. Figure 4-13 also includes data for 2004 for the entire PJM Control Area, including all integrated control zones. The PJM overall EFORd for 2004 was 7.9 percent. The EFORd is reported only for 2004 for the entire PJM Control Area as data are either not available or incomplete for the years 1994 through 2003 for the AEP, DAY and ComEd Control Zones.

Figure 4-13 - Trends in PJM equivalent demand forced outage rate (EFORd): Calendar years 1994 to 2004



Market Structure for the ComEd Capacity Market

Ownership Concentration

Phases 2 and 3 (June through December 2004)

As the discussion of market structure for PJM Capacity Markets explains, concentration ratios[27] are a summary measure of market share, a key element of market structure.

MMU structural analysis indicates that ComEd's Capacity Credit Markets from June 1 of Phase 2, through Phase 3 of 2004, exhibited high levels of concentration in the Monthly and Multimonthly Capacity Credit Markets.[28] As shown in Table 4-10, HHIs for Monthly and Multimonthly Capacity Credit Markets averaged 6419, with a maximum of 10000 and a minimum of 2804. One entity owned or controlled nearly two-thirds of total capacity in the ComEd Control Zone.

Table 4-10 - ComEd Capacity Market HHI: Seven months ended December 31, 2004

Statistic	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	N/A	6419
Minimum	N/A	2804
Maximum	N/A	10000

Table 4-11 - ComEd Capacity Market residual supply index (RSI): Seven months ended December 31, 2004

Statistic	Daily Market RSI	Monthly and Multimonthly Market RSI
Average	N/A	2.58
Minimum	N/A	0.00
Maximum	N/A	25.60

Table 4-11 shows RSI values for the Monthly and Multimonthly Capacity Credit Market Auctions for the ComEd Capacity Market. A minimum RSI value of 0 means that only one capacity supplier participated in at least one auction. The high average RSI value of 2.58 and the high maximum RSI value were, in part, the result of the relatively small volumes that were bid in the Capacity Credit Market Auctions, as shown in Table 4-12. Of the 48 capacity auctions held for ComEd in 2004, 26 had RSI values of less than 1.0, meaning that at least one supplier was pivotal in these auctions.

In response to identified structural market power issues in the ComEd Capacity Market, in December 2003, PJM filed a market power mitigation proposal with the FERC to limit capacity offers to the higher of $30 per MW-day or the demonstrated incremental costs of specific capacity

27 See Section 2, "Energy Market," for a discussion of concentration ratios and the HHI.
28 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.

resources. The $30 limit was based on the estimated going-forward costs of a combustion turbine. The FERC denied PJM's market power mitigation proposal in August 2004 based on a finding that there was an overall $160 per MW-day offer cap in place and that the potential for market power in the ComEd Capacity Market did not warrant the proposed mitigation measures.[29]

Demand

Phases 2 and 3 (June through December 2004)

During the seven-month period ended December 31, 2004, PJM EDCs together had an approximately 86 percent market share of load obligation in the ComEd Capacity Market (calculated from Table 4-12). Though all customers in the ComEd Control Zone were eligible for retail access, switching was generally limited to larger commercial and industrial (C&I) customers.[30] Switching was affected by a number of factors. The local utility's bundled rates have been fixed at, or below, 1997 levels since the passage of the Illinois Electric Service Customer Choice and Rate Relief Law of 1997.[31] In addition, any customer switching from bundled service to a retail choice option must pay a transition charge on the energy bought from alternative sources.

Table 4-12 - Load obligation served by ComEd Capacity Market sectors: Seven months ended December 31, 2004

	ComEd Control Zone EDCs			ComEd Control Zone EDC Affiliates			Non-ComEd Control Zone EDC or Affiliates			Not Affiliated with EDCs		
	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation
Jan	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Feb	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Apr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
May	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Jun	21,506	142	0.7%	1,290	212	16.4%	2,366	-354	-15.0%	0	0	0.0%
Jul	21,611	142	0.7%	1,196	212	17.7%	2,354	-244	-10.4%	0	-110	0.0%
Aug	21,838	146	0.7%	1,193	212	17.8%	2,130	-248	-11.7%	0	-110	0.0%
Sep	21,573	146	0.7%	1,254	212	16.9%	2,336	-298	-12.8%	0	-60	0.0%
Oct	14,271	51	0.4%	834	-88	-10.6%	1,560	55	3.5%	0	-18	0.0%
Nov	14,260	51	0.4%	838	-88	-10.5%	1,567	68	4.3%	0	-31	0.0%
Dec	14,266	56	0.4%	834	-88	-10.6%	1,565	68	4.3%	0	-36	0.0%
Average	18,466	105	0.6%	1,062	83	7.8%	1,981	-136	-6.8%	0	-52	0.0%

Table 4-12 also shows how various market sectors rely on the Capacity Credit Market. The measure of reliance on the Capacity Credit Market is the sector's monthly net Capacity Credit Market position divided by the sector's capacity obligation. A negative CCM credit value means that a sector has

29 108 FERC ¶61,187 (2004).
30 See Illinois Commerce Commission, "Competition in Illinois Retail Electric Markets in 2003" (April 2004) <.http://www.icc.state.il.us/ec/docs/040414garpt16120.pdf > (156 KB). In a phone interview on January 7, 2005, ICC staff confirmed that switching remains limited to the larger customers.
31 Illinois General Assembly, "Electric Service Customer Choice and Rate Relief Law of 1997," (220 ILCS 5/16-111 (b)).

sold more capacity credits than it has purchased for a month. A positive CCM credit value means that a sector has purchased more capacity credits than it has sold for a month. ComEd Control Zone EDCs and affiliates were net purchasers in the Capacity Credit Market while non-ComEd Control Zone EDC affiliates and entities not affiliated with EDCs were net sellers.

Commonwealth Edison Company (an EDC in the ComEd Control Zone) is 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 an average of 99.4 percent of its capacity obligation through bilateral transactions with this affiliate. Even though it satisfied less than 1 percent of its capacity obligation through the ComEd Capacity Credit Market, Commonwealth Edison Company was a major player in this market since its net purchases were over 50 percent of the total volume in the market for the seven-month period.

Supply and Demand

Phases 2 and 3 (June through December 2004)

The ComEd Control Area 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 operates under rules based on installed capacity with obligation fixed on a monthly basis. There is no daily capacity credit market. The interim ComEd Capacity Market structure includes three intervals: June to September 2004; October to December 2004; and January to May 2005. The capacity obligation for each interval is based on the forecasted interval peak and the installed reserve margin, both of which are recalculated for each interval.[32] These rules will remain in effect through May 31, 2005, after which all ComEd Control Zone capacity obligations will be satisfied under the capacity market rules that are in effect on that date for the entire RTO.[33]

The level of resources available to satisfy the capacity obligation in the ComEd Capacity Market during any month reflects 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. For the seven-month period ended December 31, 2004, the ComEd Capacity Credit Market had an average net excess of 5,672 MW. (See Table 4-13.)[34]

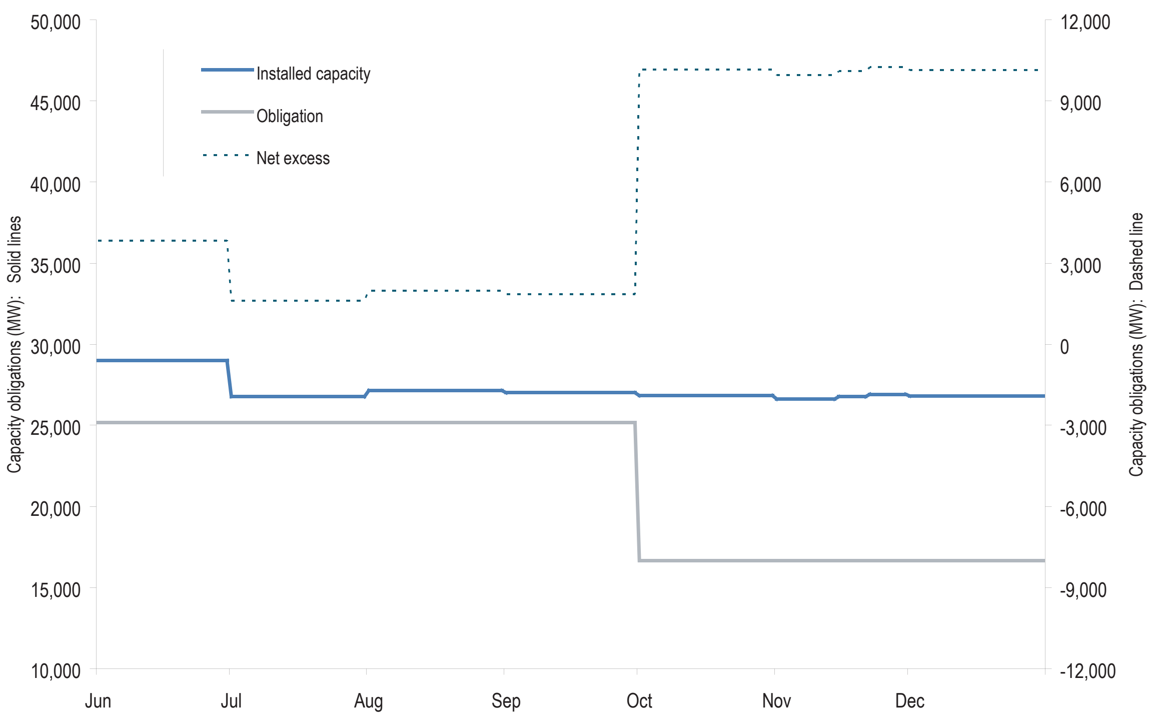
As shown in Figure 4-14, during the last seven months of calendar year 2004, capacity resources exceeded capacity obligations in the ComEd Capacity Market every month. The 8,498 MW decrease in obligation from 25,163 MW to 16,665 MW and the corresponding 8,317 MW increase in net excess from 1,852 MW to 10,169 MW as Phase 3 began were caused by the downward change to the capacity obligation to reflect the lower interval peak and higher installed reserve margin of the October to December period.

32 "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.
33 See Appendix E, "Capacity Markets."
34 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.

Table 4-13 - ComEd capacity summary (MW): Seven months ended December 31, 2004

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	27,181	750	26,615	28,999
Unforced Capacity	27,181	750	26,615	28,999
Obligation	21,509	4,216	16,665	25,163
Sum of Excess	5,672	3,935	1,609	10,249
Sum of Deficiency	0	0	0	0
Net Excess	5,672	3,935	1,609	10,249
Imports	388	14	360	404
Exports	1,223	281	747	1,597
Net Exchange	-835	291	-1,237	-343
Unit-Specific Transactions	6,306	542	5,683	6,775
Capacity Credit Transactions	26,703	2,363	23,659	29,025
Internal Bilateral Transactions	33,009	2,898	29,342	35,801
Daily Capacity Credits	0	0	0	0
Monthly Capacity Credits	91	63	10	171
Multimonthly Capacity Credits	1,208	243	912	1,457
All Capacity Credits	1,299	304	949	1,629
MIL Credits	263	96	153	346

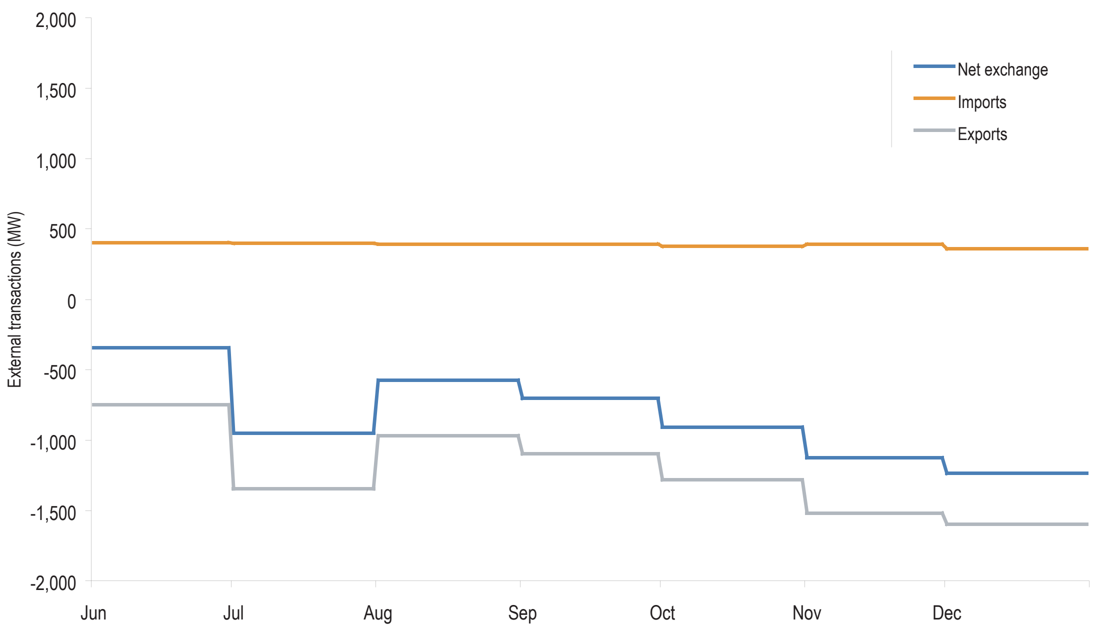
Figure 4-14 -Capacity obligations to the ComEd Capacity Market: Seven months ended December 31, 2004



External Bilateral Transactions

ComEd capacity resources may be traded bilaterally within and outside of ComEd. External bilateral transactions are imports and exports of capacity resources and may include areas inside and outside the PJM footprint. Figure 4-15 presents ComEd's external bilateral capacity transaction data for the seven-month period ended December 31, 2004. (Table 4-13 also includes data on imports and exports.) During this period, ComEd was a net exporter of capacity resources. Capacity imports averaged 388 MW and capacity exports averaged 1,223 MW, resulting in an average net exchange of -835 MW of capacity resources. Net exchange is equal to imports less exports.

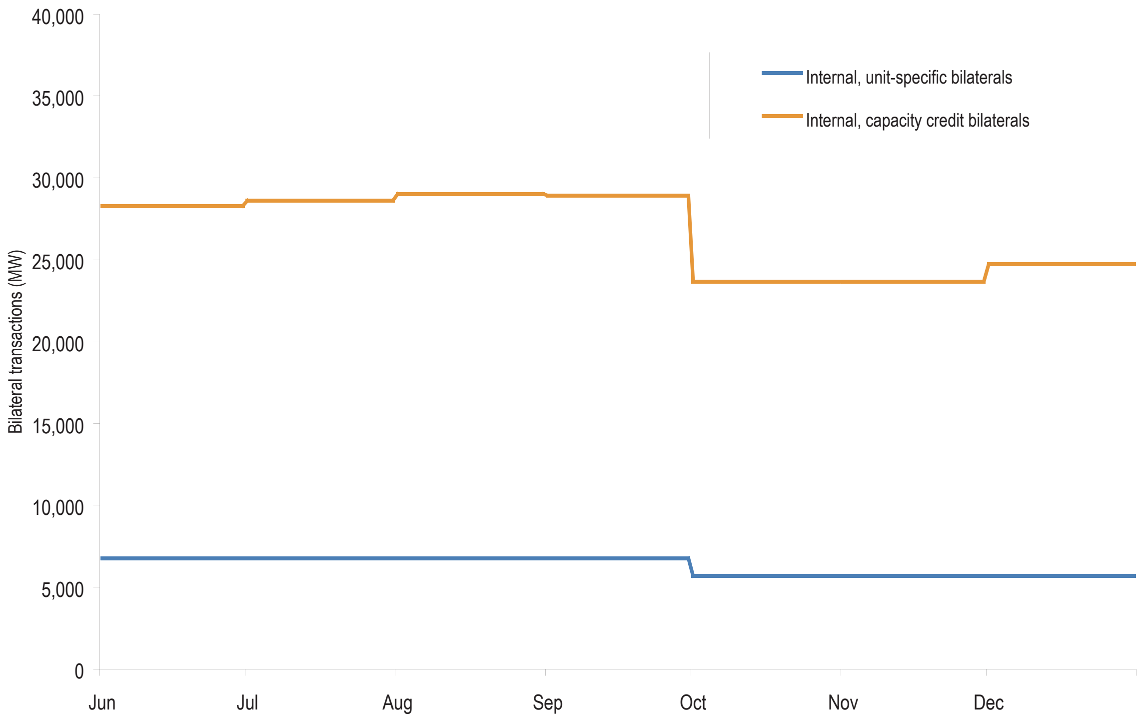
Figure 4-15 - External ComEd Capacity Market transactions: Seven months ended December 31, 2004



Internal Bilateral Transactions

Figure 4-16 presents data on ComEd's internal bilateral capacity transactions for the seven months ended December 31, 2004. (Table 4-13 also includes data on internal bilateral transactions.) Both unit-specific bilaterals and capacity credit bilaterals decreased on October 1, 2004, when lower obligations for the October to December interval became effective. Unit-specific bilaterals decreased 1,092 MW from 6,775 MW to 5,683 MW while capacity credit bilaterals decreased 5,268 MW from 28,927 MW to 23,659 MW. Bilateral capacity transactions can total more than the obligation because capacity credits can be traded multiple times among entities.

Figure 4-16 - Internal bilateral ComEd Capacity Market transactions: Seven months ended December 31, 2004



Market Performance for the ComEd Capacity Market

Capacity Credit Market Volumes

Between April and December 2004, the PJM RTO operated 48 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.[35] Table 4-13 shows that Monthly and Multimonthly Capacity Credits averaged 1,299 MW, or about 6 percent of the average capacity obligation for the seven months ending December 31, 2004. Table 4-14 shows monthly ComEd capacity credit market average daily volumes. Average daily volumes decreased by 680 MW from 1,629 MW to 949 MW when Phase 3 began and the obligation decreased for the October to December interval.

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

Capacity Credit Market Prices

Table 4-14 also shows the ComEd monthly and multimonthly capacity credit market prices for June through December 31, 2004. The volume-weighted average prices ranged from a low of $24.17 per MW-day in December to a high of $32.26 per MW-day in July. These prices were, with the exception of July, less than the $30 per MW-day offer cap that had been proposed by PJM to mitigate market power in the ComEd Capacity Market.

Table 4-14 - ComEd Capacity Credit Markets: Seven months ended December 31, 2004

	Monthly and Multimonthly Volume (MW)	Monthly and Multimonthly Weighted-Average Price ($ per MW-day)
Jan	N/A	N/A
Feb	N/A	N/A
Mar	N/A	N/A
Apr	N/A	N/A
May	N/A	N/A
Jun	1,507	$29.06
Jul	1,525	$32.26
Aug	1,584	$28.77
Sep	1,629	$28.64
Oct	949	$24.43
Nov	952	$24.29
Dec	957	$24.17
Average Jun-Dec	1,299	$27.98

Although the market structure in the ComEd Capacity Market was highly concentrated and auctions were frequently characterized by a single pivotal supplier, market performance results were consistent with the competitive benchmark established prior to the market by the MMU of $30 per MW-day. Market sellers chose to offer their capacity to the market at prices which were generally near, or below, the $30 per MW-day level. While there is no information to support the statement that individual suppliers offered their capacity at a competitive price based on unit costs, the markets did clear with only a few exceptions at a price less than $30 per MW-day. The conclusion is thus that the ComEd Capacity Market results were reasonably competitive in 2004.