SECTION 4 – INTERCHANGE TRANSACTIONS

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials.

Analysis of 2006 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM integrated five new control zones. When making comparisons to 2004 and 2005, the *2006 State of the Market Report* refers to three phases in calendar year 2004 and two phases in 2005 that correspond to those integrations.[1]

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports.** During 2006, PJM was a net exporter of energy, with monthly net interchange averaging -1.5 million MWh.[2] Gross monthly import volumes averaged 2.2 million MWh while gross monthly exports averaged 3.7 million MWh.

- **Transactions in the Day-Ahead Energy Market.** While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, the share of activity in the Day-Ahead Energy Market has increased substantially. In 2006, gross imports in the Day-Ahead Energy Market were 77 percent of the Real-Time Market's gross imports (50 percent in 2005) while gross exports in the Day-Ahead Market were 86 percent of the Real-Time Market's gross exports (50 percent in 2005) and net interchange in the Day-Ahead Energy Market was almost identical to net interchange in the Real-Time Energy Market.

- **Interface Imports and Exports.**[3] There were net exports at 15 of PJM's 21 interfaces in 2006. Three interfaces accounted for 65 percent of the total net exports, PJM/Tennessee Valley Authority (TVA) with 33 percent, PJM/MidAmerican Energy Company (MEC) with 17 percent and PJM/New York Independent System Operator (NYIS) with 15 percent of the net export volume. There were net imports at five of PJM's interfaces. Three interfaces accounted for 97 percent of the net import volume, PJM/Ohio Valley Electric Corporation (OVEC) with 76 percent, PJM/Illinois Power Company (IP) with 12 percent and PJM/Duke Energy Corp. (DUK) with 9 percent of the net import volume.

1 For additional information on PJM's footprint and the definition of these phases, see *2006 State of the Market Report,* Volume II, Appendix A, "PJM Geography."

2 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

3 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.

Interchange Transaction Topics

- **Operating Agreements with Bordering Areas.**

  - **PJM/Midwest ISO Joint Operating Agreement (JOA).** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." continued in its second, and final, phase of implementation including market-to-market activity and coordinated market-based congestion management within and between both markets.[4]

  - **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[5] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2006.

  - **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[6] On September 9, 2005, the United States Federal Energy Regulatory Commission (FERC) approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2006.

- **PJM TLRs.** The number of transmission loading relief procedures (TLRs) issued by PJM declined from 2005. The reduction in TLRs declared by both PJM and the Midwest ISO is evidence that market signals are being used to manage inter area transactions rather than market interventions.

- **PJM Interface Pricing with Organized Markets.**

  - **PJM and Midwest ISO Interface Pricing.** During 2006, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.

  - **PJM and New York ISO Interface Pricing.** During 2006, the relationship between prices at the PJM/NYIS Interface and at the New York Independent System Operator (NYISO) PJM proxy bus reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and NYISO. As in 2005, both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

  - **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.**[7] PJM continued to operate under the terms of the operating protocol (developed in 2005) during 2006.[8] Con Edison, however, is concerned that there have been apparent departures from protocol requirements.

4 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 31, 2003) (Accessed January 8, 2007) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,331 KB).

5 See "Joint Reliability Coordination (JRCA) among the Midwest ISO, PJM and TVA" (April 22, 2005) (Accessed January 17, 2007) <http://www.pjm.com/documents/downloads/agreements/ 20050422-jrca-final.pdf> (145 KB).

6 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed January 17, 2007) <http://www.pjm.com/documents/ferc/ documents/2005/20050729-er05-___-000.pdf> (2.90 MB).

7 Prior state of the market reports indicated that this contract is an agreement between Con Edison and PSEG. The contract is between Con Edison and PSE&G, a wholly owned subsidiary of PSEG.

8 111 FERC ¶ 61,228 (2005).

Periodic meetings were held with all participants to discuss the operation and progress towards improved delivery. Formal filings to implement further improvements are expected in 2007.

Interchange Transaction Issues

- **Loop Flows.** Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows 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. Although PJM's total scheduled and actual flows differed by less than 2 percent in 2006, there were significant differences for individual interfaces. Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

- **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As in 2005, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight off-peak hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows. The PJM/MECS differences and the PJM/TVA differences were in opposite directions. The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

- **Loop Flows at PJM's Southern Interfaces.** There was a persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) to the west and PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK to the east) that grew larger through the summer. In the southwest for example, while actual flows at the PJM/TVA and PJM/EKPC Interfaces were relatively small exports, scheduled energy exports at these interfaces were very large. The scheduled exports increased further in June, July and August.

  In order to reflect the actual flow of transactions associated with the southwest and southeast interface pricing points, on October 1, 2006, PJM began to price imports and exports differently based on their impacts on the PJM transmission system. After the pricing point change, scheduled flows more closely matched actual flows, primarily as a result of reductions in scheduled flows while actual flows remained relatively unchanged. In particular, a significant level of scheduled exports to the southwest stopped after the modification of the pricing points. A small number of market participants had been regularly scheduling large exports and the decline in their scheduling activity was responsible for most of the improved convergence between actual and scheduled flows.

- **Data Required for Full Loop Flow Analysis.** A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The data to fully analyze loop flows affecting PJM are not currently available to PJM.

- **Wisconsin Public Service Corporation Complaint.** On August 15, 2006, the Wisconsin Public Service Corporation (WPS) filed a complaint against PJM and the Midwest ISO at the FERC requesting that the FERC direct PJM and Midwest ISO (the regional transmission organizations (RTOs)) to promptly institute joint unit commitment and dispatch over the entire PJM/MISO footprint. The RTOs responded that an appropriate cost-benefit analysis does not justify joint dispatch at the present time. Nonetheless the RTOs recognize that there are actions that can be taken to address the lack of convergence of shadow prices. The RTOs are developing an approach to improve shadow price convergence.

- **Ramp Reservation Rule Change.** In early 2006 the number of market participant complaints regarding the inability to obtain ramp in a timely manner and complaints about large ramp volume swings became more persistent. The MMU's efforts to publicly identify the issues with such conduct resulted in improved behavior, but similar efforts in the past had only temporary effects. As a result, the MMU developed, PJM proposed, and the membership agreed, to changes in the ramp reservation rules to impose limits on the time that a ramp reservation could be held without an associated energy schedule. The new rules had a significant, positive impact on ramp reservation behavior.

Conclusion

Transactions between PJM and the multiple control areas contiguous to PJM are part of a single energy market. While some of these contiguous control areas are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market in the Eastern Interconnection. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and least cost, security-constrained economic dispatch. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are nontransparent.

The PJM Market Monitoring Unit (MMU) analyzed the transactions between PJM and neighboring control areas for 2006 including evolving transactions patterns, economics and issues. PJM continued to be a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 65 percent of the total net exports and three interfaces accounted for 97 percent of the net import volume. While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, the share of activity in the Day-Ahead Energy Market has increased substantially to 77 percent and 86 percent of gross imports and exports, respectively, while net interchange in the Day-Ahead Market is approximately equal to that in the Real-Time Energy Market.

As the data show, there is a substantial level of transactions between PJM and the contiguous control areas. The transactions with other market areas are driven by the market fundamentals within each area and between market areas. However, there is room to improve current market-to-market coordination to ensure that these areas together more closely approach the outcomes and opportunities of a single, transparent market. The transactions with non market areas are driven by a mix of incentives including market fundamentals but are more difficult to manage because of the inherent inconsistency between the contract path approach taken in non market areas and the explicit locational-price-driven approach in market areas. A significant issue is the ability of non market transactions to impose uncompensated costs on market areas in the absence of transparency and appropriate market signals. For interactions with both market and non market areas, the goal is to increase the role of market forces consistent with actual power flows and more closely approach the outcomes and opportunities of a single, transparent market.

In order to manage interactions with other market areas, PJM has entered into formal agreements with a number of control areas. The redispatch agreement between PJM and the Midwest ISO is a model for such agreements and is being continuously improved. As interactions with external areas are increasingly governed by economic fundamentals, interface prices and volumes reflect supply and demand conditions and the number of required interventions in the market has declined, as measured for example by the reduction in TLRs declared by both PJM and the Midwest ISO in 2006.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other control areas as a first step. In addition, PJM has attempted to address loop flows by creating and modifying interface prices that reflect actual power flows, regardless of contract path. Loop flows are also managed through the use of redispatch and TLR procedures. PJM has entered into dynamic scheduling agreements with generation owners to permit transparent, market-based signals and responses. PJM has modified the rules governing the use of limited transaction ramp capability between PJM and contiguous control areas to help ensure that transactions are free to respond to market signals and to reduce the ability to game or hoard ramp.

Loop flows are measured as the difference between actual and scheduled (contract path) flows at one or more specific interfaces. Loop flows do not exist within markets because power flows are explicitly priced under locational marginal pricing, but markets can create loop flows in external control areas. PJM attempts to manage loop flows by creating interface prices that reflect the actual power flows, regardless of contract path. As one approach to a specific loop flow issue, the southeast and southwest pricing points were consolidated into a single pricing point with separate import and export pricing. But this approach cannot be completely successful as long as it is possible to schedule a transaction and be paid based on that schedule, regardless of how the power flows.

PJM continues to face significant loop flows for reasons that are not yet fully understood, in large part as a result of inadequate access to the required data. A complete analysis of loop flow across the Eastern Interconnection could improve overall market efficiency and enhance the transparency of the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas.

Market participants at times request and receive ramp reservations that are not actually used for an energy transaction. When this happens, other market participants can be prevented from obtaining ramp reservations and PJM operations and markets can be affected by the large, last minute changes in expected external power flow. This behavior can reflect attempts to manipulate PJM prices, attempts to disadvantage competitors, mistakes by participants or unanticipated failures to complete the underlying transaction.

In response, the MMU developed, PJM proposed, and the membership supported, changes in the import and export ramp reservation rules to impose limits on the time that a ramp reservation could be held without an associated energy schedule. These changes became effective on August 7, 2006. The distributed nature of automatic expirations under the new rule has improved the efficiency of ramp usage.

PJM has also successfully used other approaches to enhance the efficiency of interactions with neighboring control areas. The Con Edison/PSE&G wheeling contracts continue to be managed under the FERC-approved protocol that has improved operations and resulted in more explicit pricing for the associated power flows.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM continues to be a net exporter of power. (See Figure 4-1 and Figure 4-3.)

During 2006, PJM was a net exporter of energy for each month. Total net interchange of -18.1 million MWh exceeded net interchange of -17.0 million MWh in 2005. The peak month for net interchange was June in 2006, -2.7 million MWh, and was January in 2005, -1.8 million MWh. Monthly gross exports averaged 3.7 million MWh and monthly gross imports averaged 2.2 million MWh for an average monthly net interchange of -1.5 million MWh.

While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, the share of activity in the Day-Ahead Energy Market has increased substantially. (See Figure 4-2.) Transactions in the Day-Ahead Market create a financial obligation to deliver in the Real-Time Market and the obligation to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Market. In 2006, gross imports in the Day-Ahead Energy Market were 77 percent of the Real-Time Market's gross imports (50 percent in 2005) while gross exports in the Day-Ahead Market were 86 percent of the Real-Time Market's gross exports (50 percent in 2005) and net interchange in the Day-Ahead Energy Market was almost identical to net interchange in the Real-Time Energy Market.

Figure 4-1 PJM real-time imports and exports: Calendar year 2006

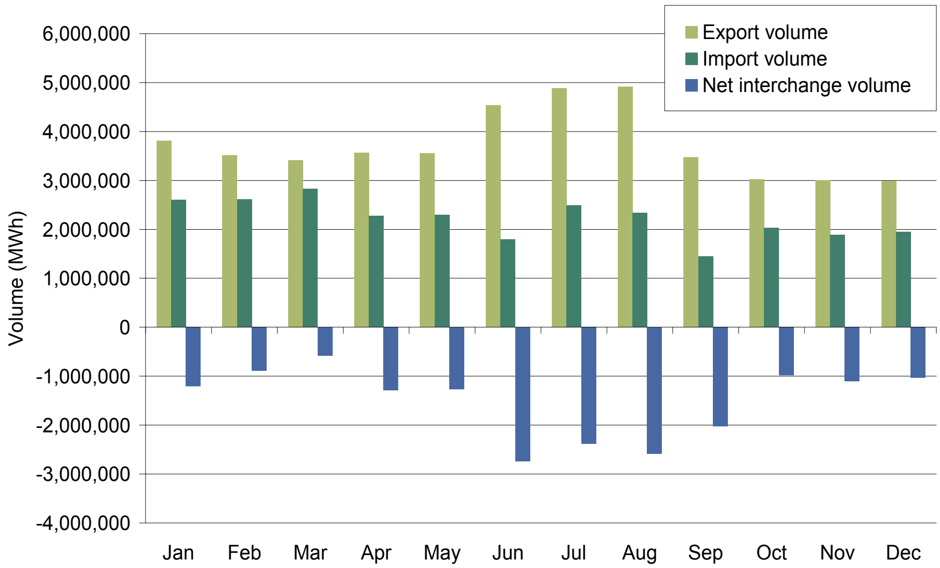


Figure 4-2 PJM day-ahead imports and exports: Calendar year 2006

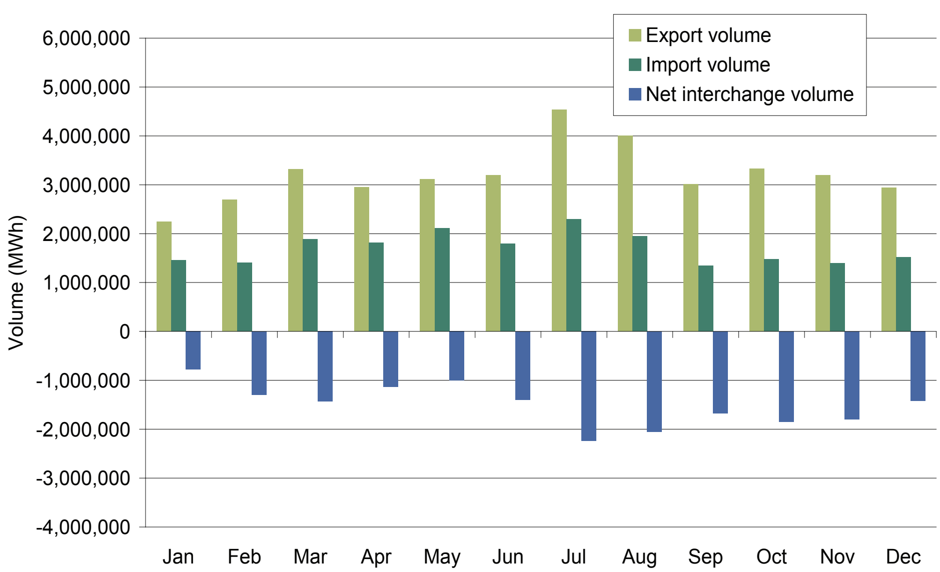
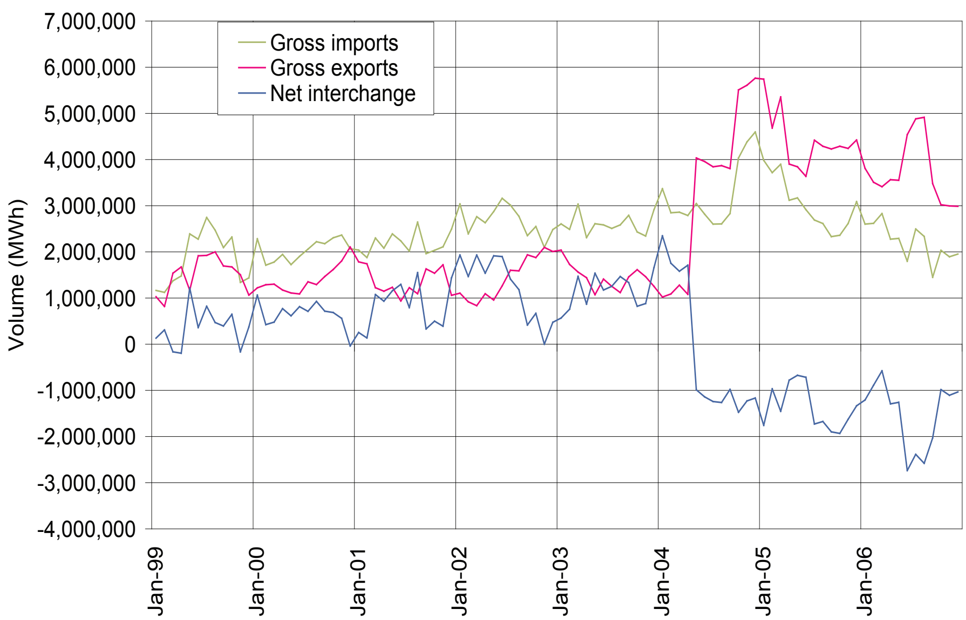


Figure 4-3 shows import and export volume for PJM from 1999 through 2006. Gross exports exhibited a particularly sharp increase in early 2004 that was not matched by imports while the increase in gross exports and imports in late 2004 was more balanced. During 2005, gross imports and exports generally declined while net interchange fluctuated with no clear trend. In 2006, imports continued to trend lower and exports, after peaking in midyear, also declined to below 2005 monthly levels by December 31, 2006. Net interchange fluctuated with no clear trend.

Figure 4-3 PJM import and export transaction volume history: Calendar years 1999 to 2006



Interface Imports and Exports

Total imports and exports are comprised of flows at each PJM interface. Net interchange in the Real-Time Market is shown by interface for 2006 in Table 4-1 while gross imports and exports are shown in Table 4-2 and Table 4-3.

There were net exports in the Real-Time Market at 15 of PJM's 21 interfaces in 2006. Three interfaces accounted for 65 percent of the total net exports, PJM/TVA with 33 percent, PJM/MEC with 17 percent and PJM/NYIS with 15 percent of the net export volume. Export transactions in the Day-Ahead Market were highest at the PJM/Northern Indiana Public Service Company (PJM/NIPS) and PJM/NYIS Interfaces in 2006. PJM/NIPS accounted for 21 percent and PJM/NYIS accounted for 17 percent of the average hourly volume.

There were net imports in the Real-Time Market at five of PJM's interfaces. Three interfaces accounted for 97 percent of the net import volume, PJM/OVEC with 76 percent, PJM/IP with 12 percent and PJM/DUK with 9 percent of the net import volume. Import transactions in the Day-Ahead Market were highest at the PJM/OVEC and PJM/NYIS Interfaces during 2006. PJM/OVEC accounted for 50 percent and PJM/NYIS accounted for 29 percent of the average hourly volume.

Table 4-1 Net interchange volume by interface (MWh x 1,000): Calendar year 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	(113.5)	(103.4)	(80.5)	(55.5)	(73.5)	(70.0)	(100.9)	(115.3)	(89.0)	(63.3)	(44.5)	(61.6)	(971.0)
ALTW	(114.1)	(88.3)	(92.9)	(49.2)	(50.8)	(24.6)	(88.7)	(104.2)	(84.5)	(90.3)	(88.8)	(83.5)	(959.9)
AMRN	(147.0)	(157.8)	(133.4)	(107.4)	(138.7)	(142.9)	(63.1)	(128.8)	(44.7)	(58.0)	(35.3)	(70.6)	(1,227.7)
CILC	0.0	0.0	(68.4)	(20.6)	0.0	(17.7)	(2.4)	0.1	(20.2)	0.0	3.4	1.0	(124.8)
CIN	(98.9)	(29.7)	(18.3)	30.6	10.4	(346.2)	(571.3)	(334.4)	(70.9)	107.2	73.1	(43.2)	(1,291.6)
CPLE	110.9	208.4	86.6	(3.8)	0.6	(129.3)	(124.5)	(148.0)	(157.7)	(39.3)	(137.7)	(106.5)	(440.3)
CPLW	(74.4)	(66.7)	(74.4)	(75.5)	(54.1)	(71.3)	(73.4)	(78.8)	(75.1)	(64.7)	(71.5)	(76.6)	(856.5)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	405.1	699.4	495.8	(89.5)	48.0	(58.2)	169.7	(94.5)	(21.9)	(134.1)	(197.9)	(54.1)	1,167.8
EKPC	(71.8)	(56.2)	(78.2)	(57.3)	(61.1)	(29.3)	(13.0)	(15.3)	(27.2)	(20.1)	(51.5)	(41.7)	(522.7)
FE	(96.0)	(145.8)	(203.6)	(169.7)	(198.9)	(184.9)	(195.2)	(226.2)	(170.8)	(197.8)	(209.7)	(206.7)	(2,205.3)
IP	311.0	20.7	330.5	325.0	340.9	20.9	31.4	6.9	4.6	69.6	81.4	9.5	1,552.4
IPL	(0.3)	(1.0)	(0.3)	0.0	(0.2)	0.0	(1.3)	(0.4)	0.0	(0.2)	(0.3)	(0.3)	(4.3)
LGEE	(1.3)	(1.0)	(0.4)	6.0	7.4	6.9	0.6	(10.1)	36.8	86.4	142.1	46.8	320.2
MEC	(559.3)	(544.3)	(326.3)	(156.0)	(224.7)	(524.3)	(784.7)	(614.4)	(377.2)	(466.3)	(395.8)	(389.8)	(5,363.1)
MECS	(110.5)	(89.8)	(105.2)	(133.6)	(132.7)	(104.8)	(137.7)	(110.6)	(92.8)	(57.1)	(81.9)	(64.4)	(1,221.1)
NIPS	(4.6)	0.9	(16.7)	(4.0)	(0.7)	(6.6)	3.9	(3.2)	(4.7)	59.9	63.2	23.4	110.8
NYIS	(526.0)	(335.1)	(219.5)	(508.5)	(564.4)	(491.9)	205.4	139.0	(744.5)	(439.9)	(686.9)	(337.0)	(4,509.3)
OVEC	846.7	828.0	880.5	826.7	823.5	778.0	711.5	837.2	645.0	836.3	826.8	886.2	9,726.4
TVA	(863.9)	(937.8)	(870.9)	(970.8)	(895.8)	(1,236.7)	(1,228.2)	(1,450.9)	(643.6)	(420.5)	(206.3)	(375.5)	(10,100.9)
WEC	(99.2)	(90.6)	(82.7)	(77.5)	(95.8)	(105.2)	(124.6)	(127.8)	(89.0)	(92.4)	(86.4)	(88.7)	(1,159.9)
Total	(1,207.1)	(890.1)	(578.3)	(1,290.6)	(1,260.6)	(2,738.1)	(2,386.5)	(2,579.7)	(2,027.4)	(984.6)	(1,104.5)	(1,033.3)	(18,080.8)

Table 4-2 Gross import volume by interface (MWh x 1,000): Calendar year 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	0.4	0.0	0.6	0.1	4.9	0.1	15.9	0.0	6.7	16.1	32.5	13.8	91.1
ALTW	0.8	0.1	0.6	0.1	0.3	0.1	0.1	0.1	0.0	0.1	0.0	0.0	2.3
AMRN	50.6	49.1	53.4	67.1	59.9	49.2	88.9	48.2	79.9	65.8	81.4	71.8	765.3
CILC	0.0	0.0	2.1	5.2	0.0	0.0	0.4	0.1	0.0	0.0	3.6	1.1	12.5
CIN	93.9	138.8	163.7	177.1	168.9	79.5	135.7	97.0	65.2	186.0	128.0	120.9	1,554.7
CPLE	303.7	399.4	259.2	152.9	169.8	104.7	144.5	138.1	69.9	145.4	59.0	115.9	2,062.5
CPLW	1.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	512.2	776.8	612.2	258.5	263.5	246.8	409.9	344.5	185.6	90.8	137.5	138.5	3,976.8
EKPC	0.0	0.1	1.3	0.0	0.0	0.7	2.9	5.6	0.9	8.9	8.0	5.2	33.6
FE	81.0	20.9	6.6	23.0	33.4	19.6	50.1	8.6	2.6	5.3	0.3	3.2	254.6
IP	312.0	20.9	331.0	325.0	341.2	20.9	31.4	7.5	4.6	69.6	81.4	9.5	1,555.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LGEE	0.2	0.0	0.0	8.5	7.9	7.5	14.9	10.5	43.4	89.0	143.6	48.9	374.4
MEC	32.3	21.4	24.2	97.9	117.8	71.3	34.2	69.3	89.7	49.2	69.9	120.2	797.4
MECS	13.4	19.3	19.6	34.0	10.8	4.2	9.6	1.3	0.1	25.2	4.7	20.5	162.7
NIPS	0.0	2.1	1.4	1.1	1.5	1.0	13.5	0.5	2.2	61.8	67.0	29.4	181.5
NYIS	340.6	315.4	451.0	286.2	275.8	397.5	808.8	738.8	220.5	349.6	216.0	346.6	4,746.8
OVEC	852.2	831.6	895.2	831.8	823.5	786.6	711.5	845.4	651.5	859.0	826.8	894.4	9,809.5
TVA	8.2	22.1	9.9	6.0	12.1	8.9	23.8	17.2	27.0	12.0	26.8	9.5	183.5
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	0.0	1.6	6.4	4.3	14.1
Total	2,602.6	2,618.5	2,832.0	2,274.5	2,291.3	1,798.6	2,496.1	2,334.5	1,449.8	2,035.4	1,892.9	1,953.7	26,579.9

Table 4-3 Gross export volume by interface (MWh x 1,000): Calendar year 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	113.9	103.4	81.1	55.6	78.4	70.1	116.8	115.3	95.7	79.4	77.0	75.4	1,062.1
ALTW	114.9	88.4	93.5	49.3	51.1	24.7	88.8	104.3	84.5	90.4	88.8	83.5	962.2
AMRN	197.6	206.9	186.8	174.5	198.6	192.1	152.0	177.0	124.6	123.8	116.7	142.4	1,993.0
CILC	0.0	0.0	70.5	25.8	0.0	17.7	2.8	0.0	20.2	0.0	0.2	0.1	137.3
CIN	192.8	168.5	182.0	146.5	158.5	425.7	707.0	431.4	136.1	78.8	54.9	164.1	2,846.3
CPLE	192.8	191.0	172.6	156.7	169.2	234.0	269.0	286.1	227.6	184.7	196.7	222.4	2,502.8
CPLW	75.5	67.2	74.4	75.5	54.1	71.3	73.4	78.8	75.1	64.7	71.5	76.6	858.1
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	107.1	77.4	116.4	348.0	215.5	305.0	240.2	439.0	207.5	224.9	335.4	192.6	2,809.0
EKPC	71.8	56.3	79.5	57.3	61.1	30.0	15.9	20.9	28.1	29.0	59.5	46.9	556.3
FE	177.0	166.7	210.2	192.7	232.3	204.5	245.3	234.8	173.4	203.1	210.0	209.9	2,459.9
IP	1.0	0.2	0.5	0.0	0.3	0.0	0.0	0.6	0.0	0.0	0.0	0.0	2.6
IPL	0.3	1.0	0.3	0.0	0.2	0.0	1.3	0.4	0.0	0.2	0.3	0.3	4.3
LGEE	1.5	1.0	0.4	2.5	0.5	0.6	14.3	20.6	6.6	2.6	1.5	2.1	54.2
MEC	591.6	565.7	350.5	253.9	342.5	595.6	818.9	683.7	466.9	515.5	465.7	510.0	6,160.5
MECS	123.9	109.1	124.8	167.6	143.5	109.0	147.3	111.9	92.9	82.3	86.6	84.9	1,383.8
NIPS	4.6	1.2	18.1	5.1	2.2	7.6	9.6	3.7	6.9	1.9	3.8	6.0	70.7
NYIS	866.6	650.5	670.5	794.7	840.2	889.4	603.4	599.8	965.0	789.5	902.9	683.6	9,256.1
OVEC	5.5	3.6	14.7	5.1	0.0	8.6	0.0	8.2	6.5	22.7	0.0	8.2	83.1
TVA	872.1	959.9	880.8	976.8	907.9	1,245.6	1,252.0	1,468.1	670.6	432.5	233.1	385.0	10,284.4
WEC	99.2	90.6	82.7	77.5	95.8	105.2	124.6	129.6	89.0	94.0	92.8	93.0	1,174.0
Total	3,809.7	3,508.6	3,410.3	3,565.1	3,551.9	4,536.7	4,882.6	4,914.2	3,477.2	3,020.0	2,997.4	2,987.0	44,660.7

Interface Pricing Points

Interface pricing points differ from interfaces. Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[9] PJM establishes prices for transactions with external control areas by assigning interface pricing points to individual areas. Interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically for areas that are both adjacent to and not adjacent to PJM. Transactions between PJM and external control areas need to be priced at the PJM border. A set of external buses is used to create such interface prices.[10] The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and external sources of energy and, therefore, to create price signals that embody underlying economic fundamentals.[11]

9 See *2006 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more detailed discussion of interface pricing.

10 See PJM, "LMP Aggregate Definitions" (December 15, 2006) (Accessed January 8, 2007) <http://www.pjm.com/markets/energy-market/downloads/20061215-aggregate-definitions.xls> (1,307 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

11 See *2006 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Table 4-4 presents the interface pricing points used during 2006.[12] On October 1, 2006, the southeast and southwest pricing points were consolidated, and the south import (SOUTHIMP) and south export (SOUTHEXP) pricing points were created to address loop flow problems.

Table 4-4 Active pricing points: Calendar year 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
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
MICHFE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP										Active	Active	Active
SOUTHEXP										Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active			
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active			

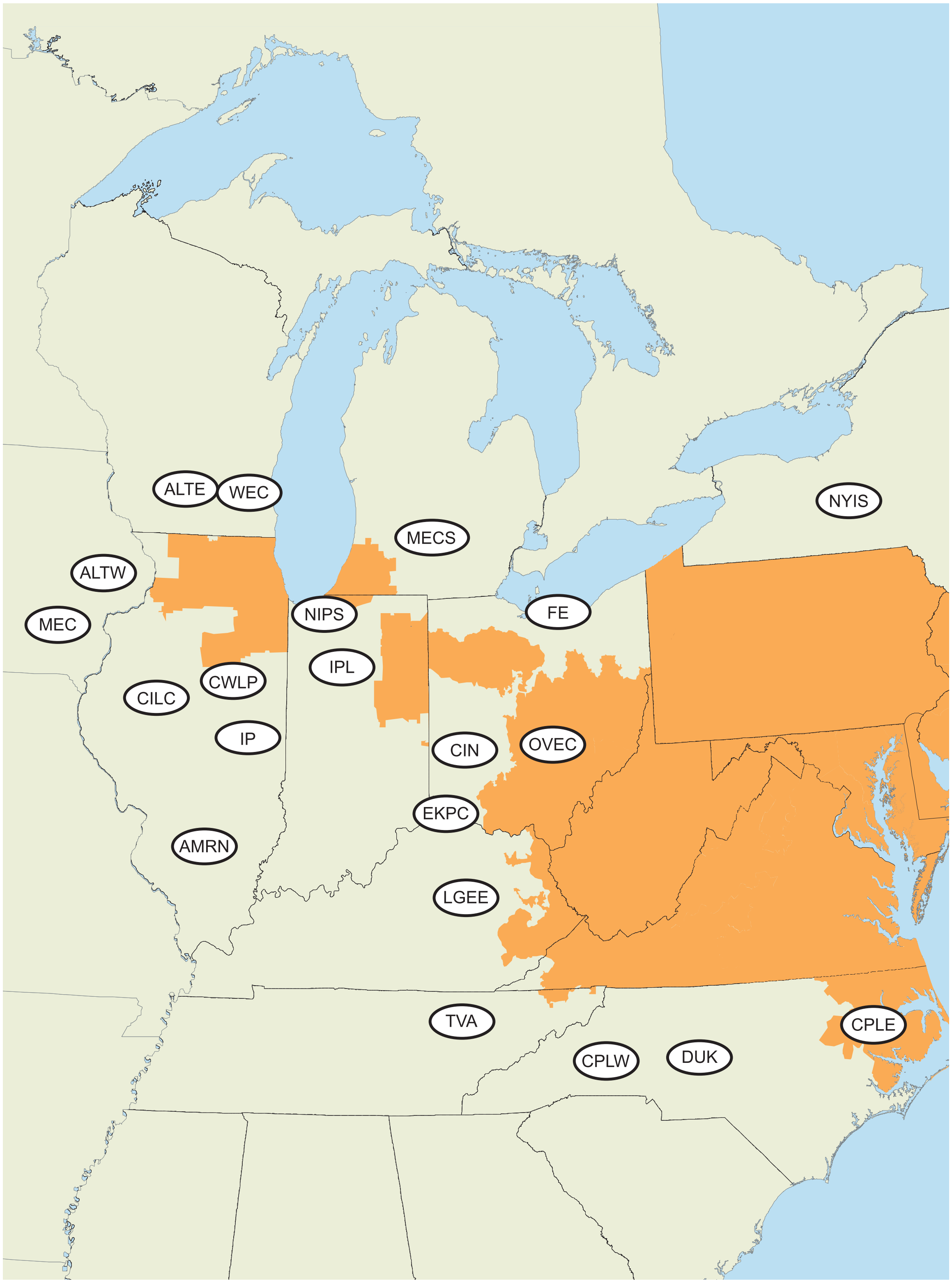
Table 4-5 Active interfaces: Calendar year 2006

PJM 2006 External Interfaces						
ALTE	ALTW	AMRN	CILC	CIN	CPLE	CPLW
CWLP	DUK	EKPC	FE	IP	IPL	LGEE
MEC	MECS	NIPS	NYIS	OVEC	TVA	WEC

The approximate geographic location of these interfaces can be seen in Figure 4-4.

12 For a more detailed discussion of this issue, see *2006 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Loop Flows at PJM's Southern Interfaces."

Figure 4-4 PJM's footprint and its external interfaces



Interchange Transaction Topics

During 2006, four broad topics emerged involving interchange transactions: PJM continued operating under agreements with bordering areas; PJM TLRs continued to be displaced by economic dispatch; PJM continues to face significant loop flow issues; and PJM addressed a problem with ramp reservation abuses that resulted in a rule change.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams' issues, PJM and its neighbors have developed and continue to work on joint operating agreements. These agreements are in various stages of development and include an implemented operating agreement with Midwest ISO, an implemented reliability agreement with TVA and an operating agreement with Progress Energy Carolinas, Inc. that is not yet fully implemented.

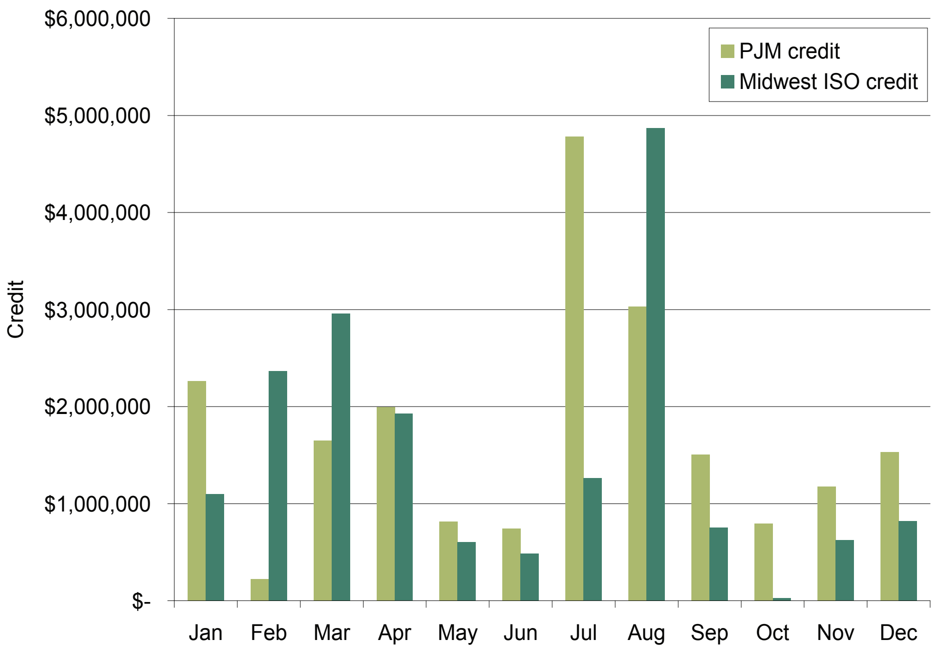
PJM/Midwest ISO Joint Operating Agreement (JOA)

On April 1, 2005, the Midwest ISO market became operational. That triggered the second, market-to-market phase, of the JOA. This second phase remained in effect through 2006.

Under the market-to-market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculate locational marginal prices (LMPs) for its interface with the other organization. Both entities calculate LMPs using network models including distribution factor impacts. PJM uses nine buses within the Midwest ISO to calculate the PJM/MISO pricing point LMP while the Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM pricing point.

In 2006, the market-to-market operations have resulted both in Midwest ISO and PJM redispatching units to control congestion in the other's area and in the exchange of payments for this redispatch. Figure 4-5 presents the monthly credits each organization has received from redispatching for the other. The largest payments from PJM to Midwest ISO during the year were the result of redispatch by Midwest ISO to relieve congestion on the Kammer #8 transformer for the loss of the Belmont–Harrison 500 kV line that was the result of PJM dispatch to meet load. Total PJM payments to Midwest ISO were $15.0 million. The largest payments from Midwest ISO to PJM during the year were the result of redispatch by PJM to relieve congestion on the Black Oak–Bedington 500 kV line for loss of the Pruntytown–Mount Storm 500 kV line that was the result of Midwest ISO dispatch to meet load. Total Midwest ISO payments to PJM were $17.7 million.

Figure 4-5 Credits for coordinated congestion management: Calendar year 2006



PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2006. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Similar to the JOA between PJM and the Midwest ISO, the JRCA uses coordinated flowgates to address congestion within and across systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2006. Since Progress Energy Carolinas is not a market system, the coordination between PEC and PJM is similar to that between the Midwest ISO and PJM during the first phase of their JOA. PEC and PJM plan to control flows over coordinated flowgates with a combination of redispatch and TLRs. The details that were expected to be completed during the first half of 2006 are still being developed. A phased approach is being discussed.

PJM TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve the issue. TLRs are generally called to control flows related to external control areas as redispatch within an LMP market can generally resolve overloads on internal transmission facilities. PJM called fewer TLRs in 2006 than had been called in 2005. Total PJM TLRs declined by 58 percent, from 326 during 2005 to 136 in 2006. (See Figure 4-6.) In addition, the number of unique flowgates for which PJM declared TLRs decreased from 69 different flowgates during 2005 to 41 different flowgates in 2006. (See Figure 4-7 for monthly data.) Of the 136 TLRs called by PJM in 2006, three facilities comprised 50 percent of the total. The three facilities were:

- **Roseland-Cedar Grove F 230 kV Line for Loss of Roseland-Cedar Grove B 230 kV Line.** These parallel path lines are located in northern New Jersey. Power transfers to New York, loop flows and loads on the PSE&G system are the main reasons for TLRs on this line (29 TLRs in 2006; 39 TLRs in 2005);

- **Wylie Ridge Transformers.** These transformers are in a 500 kV substation located in West Virginia near the Ohio River at the western edge of the AP Control Zone. West–to-east power flows frequently overload one of these transformers on a contingency basis for the loss of the other transformer (23 TLRs in 2006; 67 TLRs in 2005);

- **Kammer #200 765 to 500 kV Transformer for Loss of Belmont-Harrison 500 kV Line.** This is a 765 to 500 kV transformer located near the border of Ohio and West Virginia. The Belmont–Harrison 500 kV line runs in northern West Virginia near the southwest corner of Pennsylvania. Economic dispatch of lower cost units in the west can cause high flows at Kammer. This constraint is not easily controllable with redispatch because of lack of generation with the necessary impact (16 TLRs in 2006; 50 TLRs in 2005).

In 2006, the top three facilities for which PJM called TLRs were the same as in 2005 although the total number of TLRs on each of these facilities declined.

Figure 4-6 PJM and Midwest ISO TLR procedures: Calendar years 2005 and 2006

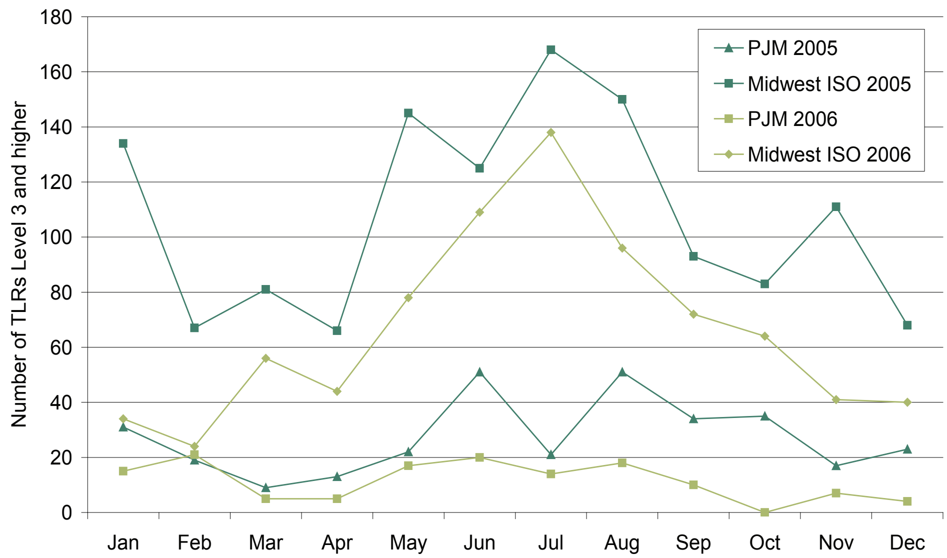
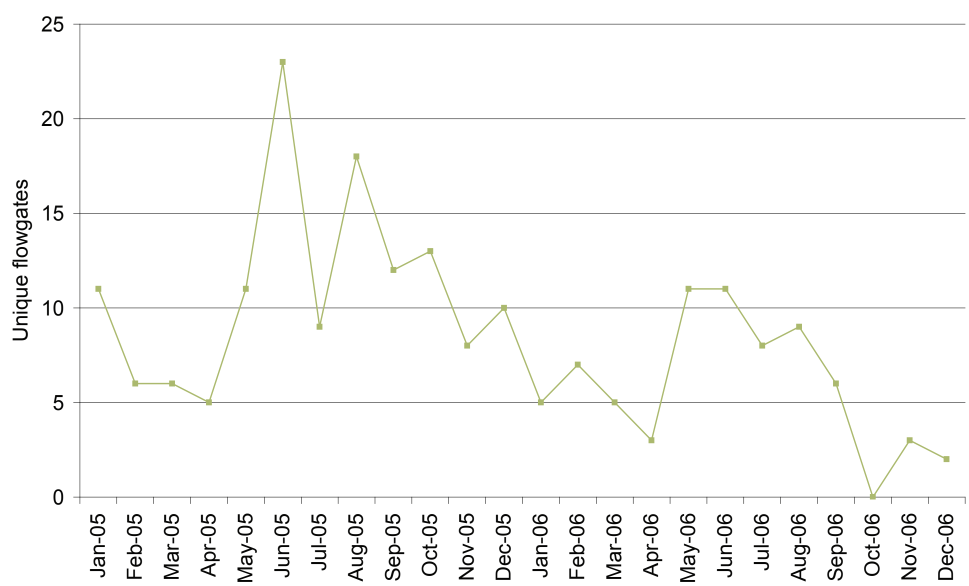


Figure 4-7 Number of unique PJM flowgates: Calendar years 2005 to 2006



PJM Interface Pricing with Organized Markets

During 2006, prices at the borders between PJM and the Midwest ISO and between PJM and the NYISO were consistent with competitive forces. A wheeling contract between New York's Con Edison and New Jersey's PSE&G required involvement from both PJM and NYISO as operators of the relevant transmission facilities.

PJM and Midwest ISO Interface Pricing

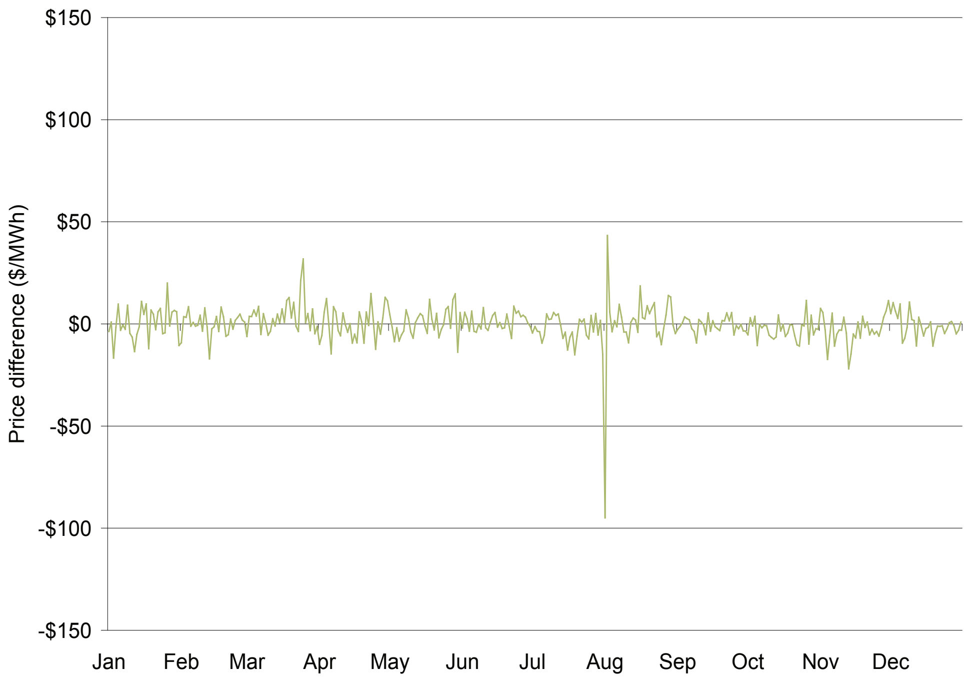
On April 1, 2005, with the introduction of price-based markets, the Midwest ISO created a new interface pricing point with PJM. Both the PJM/MISO and the MISO/PJM pricing points represent the value of power at the relevant border, as determined by each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from Midwest ISO would receive the PJM/MISO price upon entering PJM, while a transaction into Midwest ISO from PJM would receive the MISO/PJM price when entering Midwest ISO. PJM and Midwest ISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[13] within Midwest ISO to calculate the PJM/MISO interface price while Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM interface price.[14]

The 2006 hourly average interface prices for PJM/MISO and MISO/PJM were $41.80 and $41.57, respectively. The simple average difference between the MISO/PJM interface price and the PJM/MISO interface price was -$0.23 in 2006, less than 1 percent of the average PJM/MISO price. (See Figure 4-8.) The PJM/MISO interface price was slightly higher on average than the MISO/PJM price in 2006. The simple average interface price difference does not reflect the underlying hourly variability in prices during 2006.

13 See PJM, "LMP Aggregate Definitions" (December 15, 2006) (Accessed January 8, 2007) <http://www.pjm.com/markets/energy-market/downloads/20061215-aggregate-definitions.xls> (1,307 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

14 Based on information obtained from the Midwest ISO Extranet (October 21, 2005) <http://extranet.midwestiso.org/>.

Figure 4-8 Daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2006



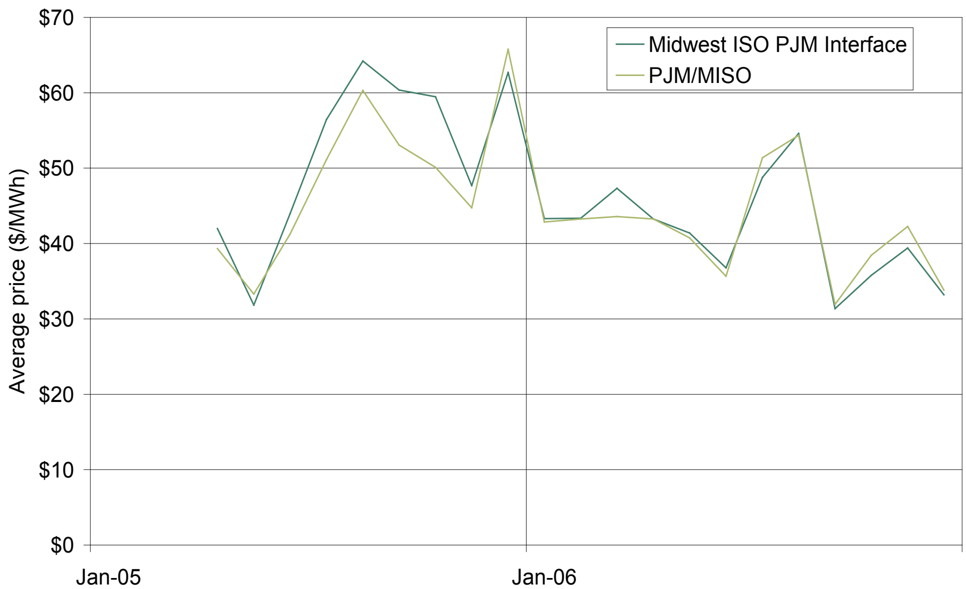
There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

During 2006, the difference between the PJM/MISO interface price and the MISO/PJM interface price fluctuated between positive and negative about eight times per day. The standard deviation of hourly price was $26.18 for the PJM/MISO price and $25.73 for the MISO/PJM interface price. The standard deviation of the difference in interface prices was $20.94. The average of the absolute value of the hourly price difference was $11.60. Absolute values reflect price differences regardless of whether they are positive or negative.

Several factors are responsible for the relationship between interface prices. The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, an observation further supported by the frequency with which price differential switches between positive and negative.

In addition, there is a significant correlation between monthly average hourly PJM and Midwest ISO interface prices during the 2006 period. Figure 4-9 shows this correlation between hourly PJM and Midwest ISO interface prices.

Figure 4-9 Monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 to 2006



PJM and NYISO Interface Pricing

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions 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.[15]

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. PJM defines its NYIS pricing point using two buses.[16] 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. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as price-capped load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

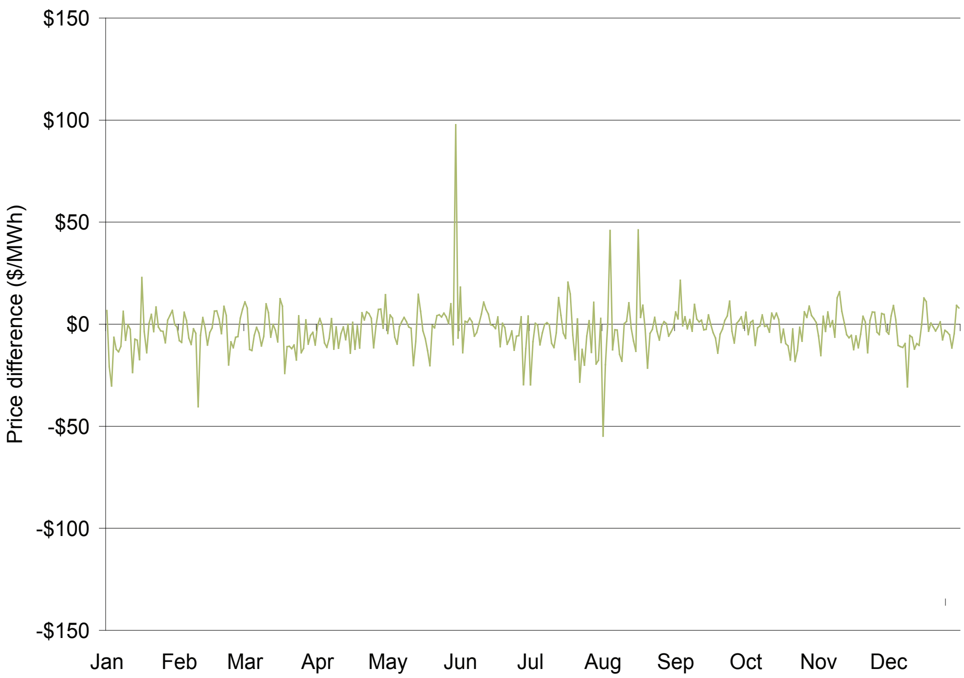
The 2006 hourly average price for PJM/NYIS and the NYISO/PJM proxy bus price were $53.44 and $50.97, respectively. The simple average difference between the PJM/NYIS interface price and the NYISO/PJM proxy bus price decreased from -$5.32 per MWh in 2005 to -$2.47 per MWh in 2006, and the variability of

15 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).

16 See PJM, "LMP Aggregate Definitions" (December 15, 2006) (Accessed January 8, 2007) <http://www.pjm.com/markets/energy-market/downloads/20061215-aggregate-definitions.xls> (1,307 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

the difference also decreased. (See Figure 4-10.) The fact that PJM's net export volume to New York for 2006 was 49 percent lower than the five-year, 2001-to-2005 average is at least partially consistent with the fact that the PJM/NYIS price continued to be greater than the NYISO/PJM price. The simple average interface price difference does not reflect the continuing, substantial underlying hourly variability in prices during 2005 and 2006.

Figure 4-10 Daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2006



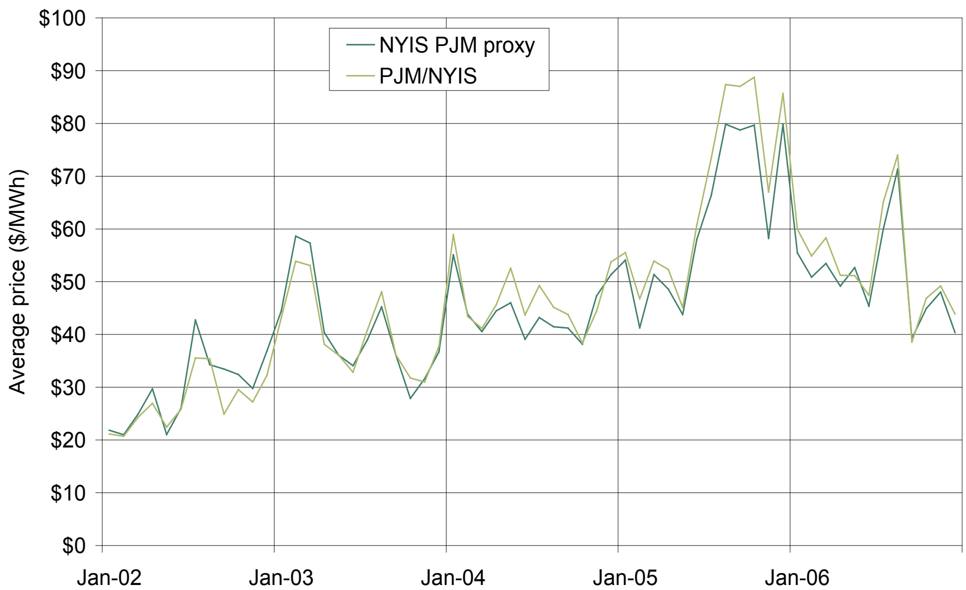
There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

The difference between the PJM/NYIS interface price and the NYISO/PJM price continued to fluctuate between positive and negative about eight times per day during 2006 as it did in 2003, 2004 and 2005. The standard deviation of hourly price was $25.00 in 2003, $23.64 in 2004, $42.93 in 2005 and $35.23 in 2006 for the PJM/NYIS price and $37.72 in 2003, $30.00 in 2004, $41.57 in 2005 and $38.07 in 2006 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $36.21 in 2003, $29.55 in 2004, $40.22 in 2005 and $32.84 in 2006. The average of the absolute value of the hourly price difference was $16.13 in 2003, $14.01 in 2004, $23.44 in 2005 and $17.20 in 2006. 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.

There is a significant correlation between monthly average hourly PJM and NYISO interface prices during the entire period 2002 to 2006. Figure 4-11 shows this correlation between hourly PJM and NYISO interface prices.

Figure 4-11 Monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2006



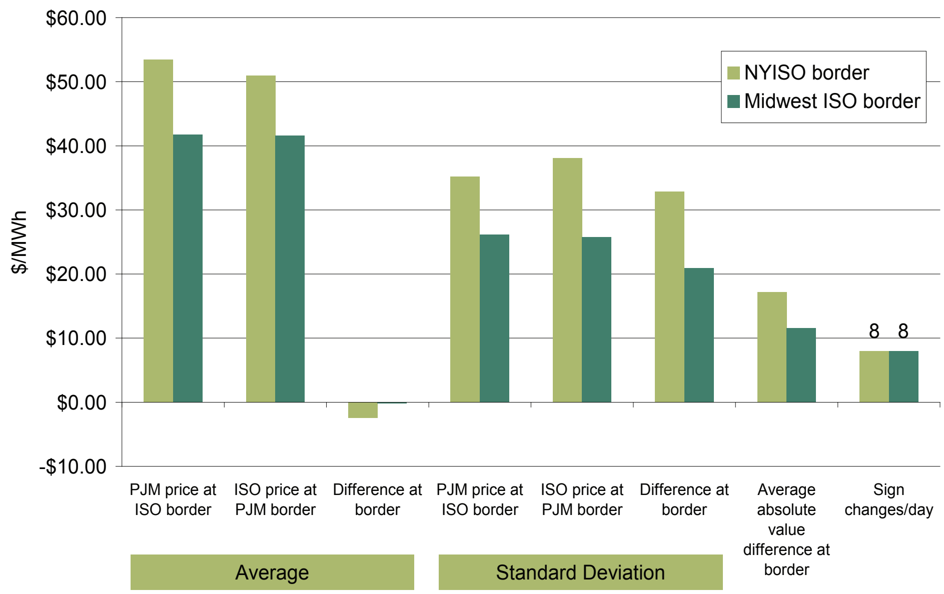
As previously noted, institutional difference between PJM and NYISO markets partially explains observed differences in border prices.[17]

Summary of Interface Pricing with Organized Markets

The key features of PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-12, including average prices and measures of variability.

17 For a description of those differences, see *2005 State of the Market Report,* Appendix D, “Interchange Transactions” (March 8, 2006), pp. 195-198.

Figure 4-12 PJM, NYISO and Midwest ISO border price averages: Calendar year 2006



Con Edison and PSE&G Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[18] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[19]

The protocol allows Con Edison to elect up to the contracted flow under each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion charges associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

18 111 FERC ¶ 61,228 (2005).

19 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2006, PSE&G's FTR revenues were less than the associated congestion charges by $0.4 million ($2.1 million in 2005) because, for the entire PJM FTR Market, revenue was insufficient to fully fund FTRs. Under the FERC order, Con Edison receives credits on an hourly basis for up to the amount of its congestion charges associated with its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. For the year, Con Edison's congestion credits were less than the associated congestion charges by $0.7 million ($8.2 million in 2005). (See Table 4-6.)

Table 4-6 Con Edison and PSE&G wheeling settlements data: Calendar year 2006

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total	Congestion Charge	$2,697,020.88	$9,165.13	$2,706,186.01	$4,159,260.00	$0.00	$4,159,260.00
	Congestion Credit			$2,036,783.63			$3,645,087.51
	Credit Adj.			$0.00			$158,833.43
	Net Charge			$669,402.38			$355,339.06

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. As a general matter, this has not occurred.

2006 Update

PJM continued to operate under the terms of the protocol during 2006. Con Edison, however, is concerned that there have been apparent departures from protocol requirements. Periodic meetings were held with all participants to discuss the operation and progress towards improved delivery. As of the end of 2006, the parties had developed a list of issues aimed to address the delivery performance. Issues under discussion included: 1) Curtailment and control of non-firm, third-party transactions; 2) Strategic phase angle regulator (PAR) tap moves for peak-load days and maintenance days; 3) Wheeling performance reporting, performance metrics and data access; and 4) Past performance and remedies. These items were expected to be completed in the first half of 2007. Table 4-6 shows the settlement values for 2006.[20]

The FERC order asked the market monitors for both PJM and NYISO to evaluate, during the protocol's initial six-month period, their ability to perform investigations ensuring that neither gaming nor abuse of market power occur. The PJM MMU concluded that there was no reason to gather data outside the bounds of the order.

In addition, the MMU has evaluated conduct under the protocol and has not identified the exercise of market power by either participant.

20 For monthly settlement values, see *2006 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions."

Interchange Transaction Issues

Loop Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow despite the fact that the system actual and scheduled flows could net to a zero difference.

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 on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

The fact that total PJM net actual interface flows were very close to net scheduled interface flows on average for 2006 as a whole is not a useful measure of loop flow. There were significant differences between scheduled and actual flows for specific individual interfaces. (See Table 4-7.) From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous control areas.

During 2006, for PJM as a whole, net scheduled and actual interchange differed by less than 2 percent. (See Table 4-7.) Actual system exports were 15.426 million MWh and so were less than the scheduled total exports of 15.699 million MWh by 0.273 million MWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 13.627 million MWh exceeding scheduled exports of 1.244 million MWh by 12.383 million MWh or 995 percent, for an average of 1.414 MW during each hour of the year. At the PJM/TVA Interface, net actual exports were less than scheduled exports by 9.916 million MWh or -97 percent. At the PJM/FE Interface, net actual imports exceeded scheduled exports by 7.715 million MWh or 214 percent. At the PJM/ALTE Interface, net scheduled exports were less than actual exports by 5.947 million MWh or 612 percent. At the PJM/NYIS Interface, net actual exports exceeded scheduled exports by 5.405 million MWh or 130 percent.

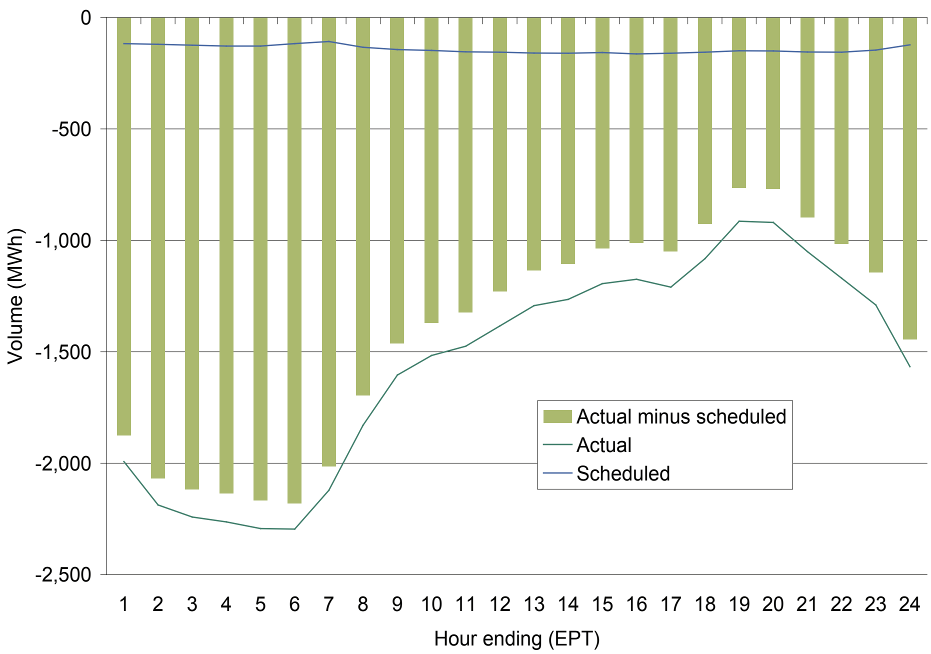
Table 4-7 Net scheduled and actual PJM interface flows (MWh x 1,000): Calendar year 2006

	Actual	Net Scheduled	Difference	Difference (Percent Net Scheduled)
ALTE	(6,918)	(971)	(5,947)	612%
ALTW	(3,067)	(956)	(2,111)	221%
AMRN	-	(1,034)	1,034	(100%)
CILC	1,209	(125)	1,334	(1067%)
CIN	4,268	452	3,816	844%
CPLE	4,632	383	4,249	1109%
CPLW	(1,966)	(857)	(1,109)	129%
CWLP	(631)	-	(631)	
DUK	(3,645)	1,229	(4,874)	(397%)
EKPC	502	(527)	1,029	(195%)
FE	4,113	(3,602)	7,715	(214%)
IP	2,461	1,553	908	58%
IPL	2,824	-	2,824	
LGEE	842	336	506	151%
MEC	(4,568)	(5,369)	801	(15%)
MECS	(13,627)	(1,244)	(12,383)	995%
NIPS	(2,604)	112	(2,716)	(2425%)
NYIS	(9,559)	(4,154)	(5,405)	130%
OVEC	11,214	10,411	803	8%
TVA	(260)	(10,176)	9,916	(97%)
WEC	(646)	(1,160)	514	(44%)
Total	(15,426)	(15,699)	273	(1.7%)

Loop Flows at the PJM/MECS and PJM/TVA Interfaces

As in 2005, the PJM/MECS Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight off-peak hours. (See Figure 4-13.) Generally, the PJM/MECS Interface is an exporting interface meaning that power flows from PJM to MECS. The actual exports exceeded the scheduled exports at that interface by an average of 2,000 MW per hour for those off-peak hours. The peak-hour difference between actual and scheduled exports averaged 1,121 MW.

Figure 4-13 PJM/MECS interface average actual minus scheduled volume: Calendar year 2006



The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows. The PJM/MECS differences and the PJM/TVA differences were in opposite directions. The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports. (See Figure 4-14 and Figure 4-15.) The consolidation of the former southeast and southwest pricing points in October 2006 has had an apparent impact at the PJM/TVA Interface.[21] Figure 4-14 shows the average hourly actual, scheduled flows and the difference between them for the preconsolidation time period January 1, 2006, through September 30, 2006. Actual exports were less than scheduled exports by 1,328 MWh every hour, on average. Postconsolidation, this difference decreased by 61 percent to 514 MW (on average) each hour. (See Figure 4-15.)

21 For a more detailed discussion of this issue, see *2006 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Loop Flows at PJM's Southern Interfaces."

Figure 4-14 PJM/TVA average flows: January 1 to September 30, 2006, preconsolidation

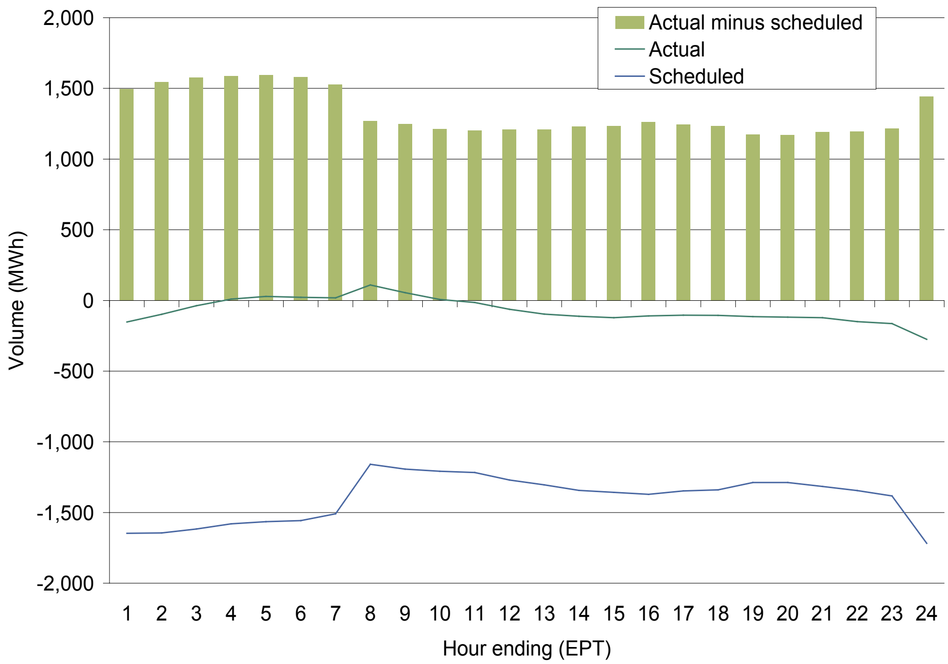
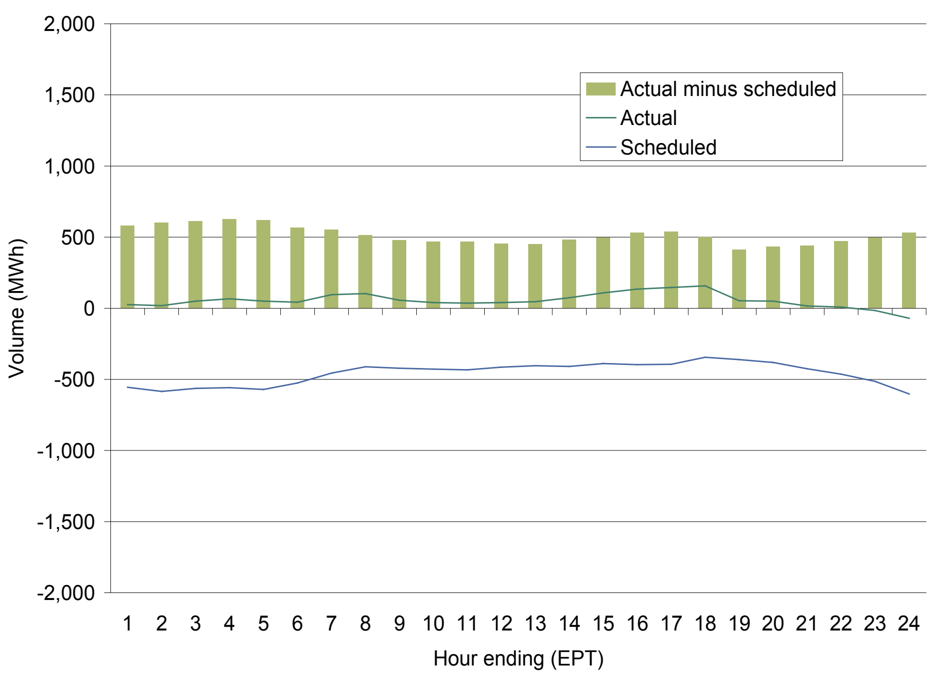


Figure 4-15 PJM/TVA average flows: October 1 to December 31, postconsolidation



Loop flows, measured as the differences between scheduled and actual flows at specific interfaces, are a significant concern. Loop flows have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear.

Loop Flows at PJM's Southern Interfaces

As Figure 4-16 and Figure 4-17 illustrate, there was a persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew larger through the summer. In the southwest for example, while actual flows at the PJM/TVA and PJM/EKPC Interfaces were relatively small exports, scheduled energy exports at these interfaces were very large. The scheduled exports increased further in June, July and August.

Figure 4-16 Southwest actual and scheduled flows: Calendar year 2006

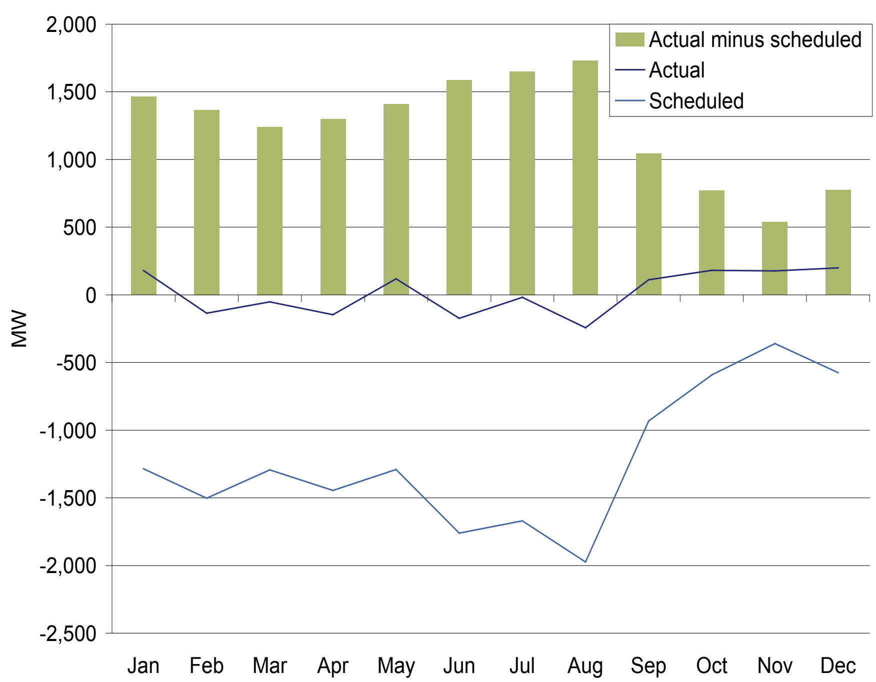
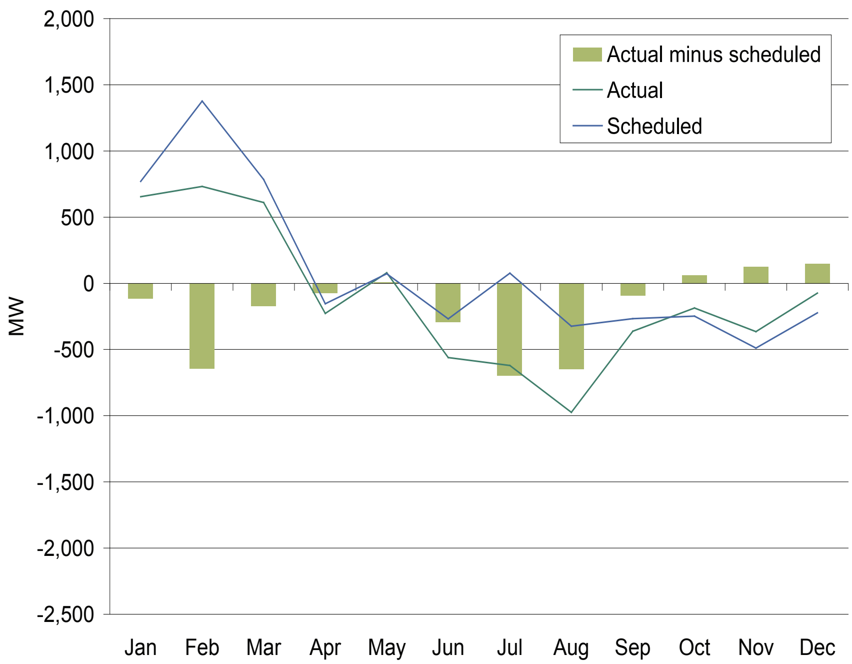
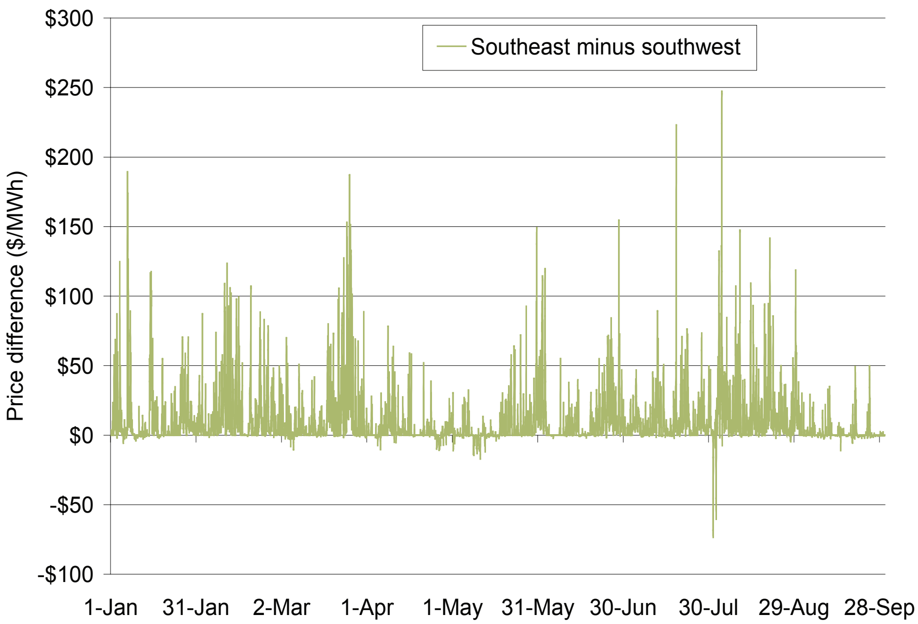


Figure 4-17 Southeast actual and scheduled flows: Calendar year 2006



The difference in price between the southeast and southwest pricing points provided incentives to schedule imports to receive the relatively higher southeast price and schedule exports to pay the lower southwest price on the export. (See Figure 4-18.)

Figure 4-18 Southeast minus southwest LMP: January to September 2006



For example, there were transactions from a source in the southeastern U.S. to a sink in the southwestern U.S. While the actual power flow took the path of least resistance directly from the source in the southeastern U.S. to the sink in the southwestern U.S., without ever flowing through PJM, the transaction was scheduled through PJM to take advantage of the pricing differential. There was a corresponding scheduled import transaction with a source in the southeast and a sink in PJM which was paid the southeast LMP as an import. Corresponding scheduled export transactions with a source in PJM and a sink in the southwest paid the southwest LMP as exports. The market participant which scheduled the transactions received the positive difference between the higher southeast LMP and the lower southwest LMP.

The average hourly price difference between the southeast and the southwest pricing points was $9.10 per MWh from January 1, 2006, through September 30, 2006. During that time period, 80 percent of the hours experienced a price differential. While PJM's prices provided an incentive to import at PJM's Southeast Interface and to export at PJM's Southwest Interface, scheduled flows, but not the corresponding actual flows, responded to the incentive. The result was false arbitrage that paid participants based on the scheduled flow despite the fact that the transactions did not provide power flows consistent with the incentive.

As a result of this developing pattern of behavior, it became clear that there was a need for additional modifications to the rules governing pricing for external transactions.[22] On August 31, 2006, PJM announced that, effective October 1, 2006, it would combine the southeast and southwest pricing points into a single

22 See "PJM Southeast and Southwest Interface Pricing Point Consolidation Approach" (August 31, 2006) (Accessed February 12, 2007) <http://www.pjm.com/committees/mrc/downloads/ 20060911-item-05-se-sw-interface--pricing-pts-consolidation.pdf > (23 KB).

south pricing point with different prices for imports and exports.[23] This change affects prices for external transactions scheduled for delivery to or delivery from control areas mapped to either the southwest or southeast interface pricing points. The rules governing the pricing of external transactions were first introduced on July 19, 2002, and were clarified in letters dated August 1, 2002, August 29, 2002, January 9, 2003, and February 24, 2003.

PJM determined that the associated transactions should receive a price more consistent with the associated power flows. PJM redefined the southeast and southwest pricing points. The PJM pricing points no longer include southwest or southeast but are: MISO; MICHFE; NIPSCO; Northwest; NYIS; Ontario IESO; OVEC; SOUTHIMP and SOUTHEXP. The SOUTHEXP interface pricing point consists of the buses that were included in the southwest and southeast interface pricing point definitions weighted by the tie line export power flow patterns. Some buses may have zero weights. The SOUTHIMP interface pricing point also consists of the buses that were included in the southwest and southeast interface pricing point definitions weighted by the tie line import power flow patterns. Again, some buses may have zero weights. As with all of PJM's external interfaces, these weights may be changed in the future to ensure the physical impact of transactions on the system is appropriately reflected in the pricing.[24] Changes in weights may occur periodically based on PJM's assessment of actual power flows. On October 4, 2006, when a PJM network model update was performed, one of the buses in the definitions was deleted and a replacement was added.

In order to reflect the actual flow of transactions associated with the southwest and southeast interface pricing points, on October 1, 2006, PJM began to price all transactions that source in PJM and sink in one of the relevant defined control areas, at the SOUTHEXP interface pricing point. Similarly, PJM has begun to price all transactions that sink in PJM and source in one of the defined control areas, at the SOUTHIMP interface pricing point. This enables PJM to price imports and exports differently based on their impacts on the PJM transmission system. The weighting of the buses included in these definitions may be adjusted to help ensure that the impacts of transactions on the transmission system are appropriately reflected in the resulting interface prices and, as such, the definitions are dynamic. PJM also has the ability to adjust bus weights for any of PJM's external interfaces. PJM monitors the flows and applies engineering judgment to determine when and if the weightings need to be adjusted.

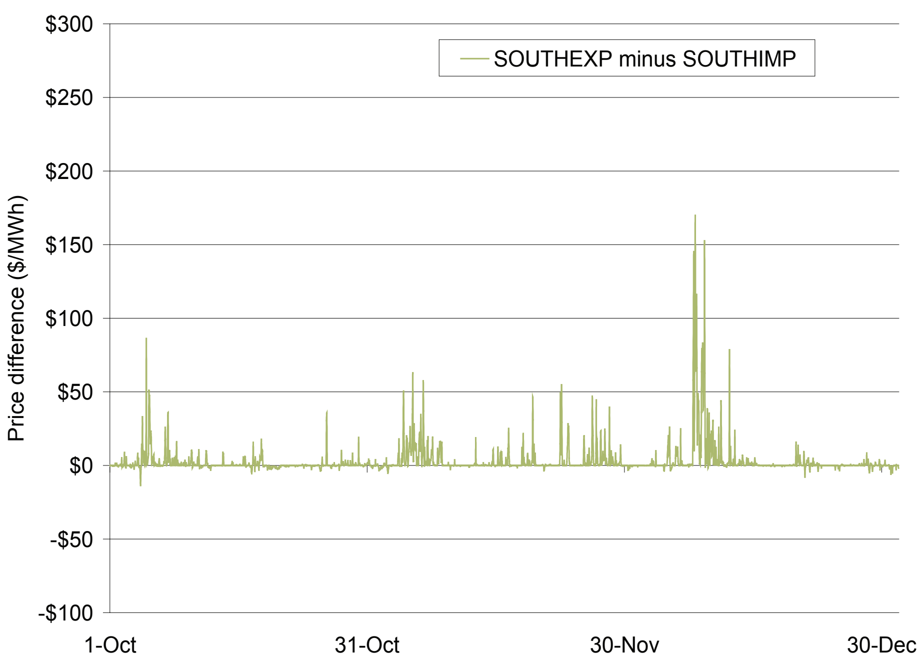
After the pricing point change, scheduled flows more closely matched actual flows, primarily as a result of reductions in scheduled flows while actual flows remained relatively unchanged. In particular, a significant level of scheduled exports to the southwest stopped after the modification of the pricing points. A small number of market participants had been regularly scheduling large exports and the decline in their scheduling activity was responsible for most of the improved convergence between actual and scheduled flows. In the southwest, average actual-minus-scheduled values peaked at about 1,700 MW per hour in August and dropped to 700 MW per hour in October. In the southeast, average actual-minus-scheduled values peaked at -674 MW in July and August and dropped to 60 MW per hour in September. The price difference between the new SOUTHEXP and SOUTHEXP prices is shown in Figure 4-19. It can be seen that when there is a difference, the SOUTHEXP price tends to be higher than SOUTHIMP. The average hourly difference

23 See "PJM Southeast and Southwest Interface Pricing Point Consolidation Approach August 31, 2006" (August 31, 2006) (Accessed January 8, 2007) <http://www.pjm.com/committees/ mrc/downloads/20060911-item-05-se-sw-interface--pricing-pts-consolidation.pdf> (23 KB).

24 See "PJM Interface Price Definition Methodology" (September 29, 2006) (Accessed January 8, 2007) <http:// www.pjm.com/markets/energy-market/downloads/20060929-interface-definition- methodology1.pdf> (33 KB).

is $2.88 per MWh over the October through December period. This price difference reflects the weighted bus components of the pricing point definitions. The nodal definition of SOUTHEXP was initially the same as the former southeast pricing point but, as a result of changes to the component bus weights, that is no longer the case. While the revised pricing is a clear improvement, the dynamic weighting may not provide the appropriate price signal to potential imports at the southeastern PJM interfaces that might help relieve congestion. PJM has offered the option to dynamically schedule units in order to ensure a match between the price and energy flows.[25]

Figure 4-19 SOUTHEXP minus SOUTHIMP LMP: October to December 2006



Data Required for Full Loop Flow Analysis

A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The term non market area is a misnomer in the sense that all electricity transactions are part of the broad energy market in the Eastern Interconnection. There are areas with transparent markets and there are areas with less transparent markets, but these areas together comprise a market and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flow.

25 A dynamically scheduled unit is a unit that is physically outside of the PJM footprint yet is treated as if it were located inside the footprint. PJM's network model can calculate an LMP at the bus for units located outside of PJM and validate that such units respond to the PJM price signal by increasing or decreasing output. Such units receive the calculated, unit-specific LMP based on the actual value of changes in the unit's output to PJM.

Data on both scheduled flows and actual flows are required in order to analyze loop flows. The data to fully analyze loop flows affecting PJM are not currently available to PJM. Scheduled flow data for transactions that touch PJM are available, but scheduled flow data for transactions that affect PJM but do not explicitly touch PJM are not available to PJM. These data exist in the form of NERC Tag data in an application developed by Open Access Technology International, Inc. (OATI) for NERC. In order to get access to all relevant Tag data on an ongoing basis, PJM would need to get permission from each control area (CA) in the Eastern Interconnection. PJM has reached agreements with the Midwest ISO, the Ontario IESO, NYISO and TVA to get a snapshot of such data for a defined historical period and has received such data. Even this limited effort required a lengthy process.

Actual flow data for generation and transactions that originate outside PJM, but affect PJM are not currently available to PJM. In order to get access to relevant actual flow data, PJM would need to get access to metered flow on relevant flowgates from each CA in the Eastern Interconnection. PJM has reached such an agreement with the Midwest ISO and is in discussions with a limited number of other CAs.

Wisconsin Public Service Corporation (WPS) Complaint

On August 15, 2006, the Wisconsin Public Service Corporation (WPS) filed a complaint against PJM and the Midwest ISO at the FERC requesting that the FERC direct PJM and Midwest ISO (the RTOs) to promptly institute joint unit commitment and dispatch over the entire PJM/MISO footprint.[26] WPS asserted that PJM and Midwest ISO commit to creating joint commitment and dispatch, but that their efforts to do so fell short. WPS asserted that the cost-benefit analysis performed by the RTOs showed that there is clear benefit to a single market dispatch and that this estimate of benefit is conservatively low. WPS argued that the failure to implement a joint commitment and dispatch has denied the public approximately $50 million per year of production cost savings and probably significantly more.

The primary evidence adduced by WPS was a comparison of prices at the PJM/MISO border and a comparison of RTO shadow prices for certain flowgates. WPS claimed that the observed difference in prices at the border and in shadow prices reflects a failure of PJM and Midwest ISO to integrate their markets.

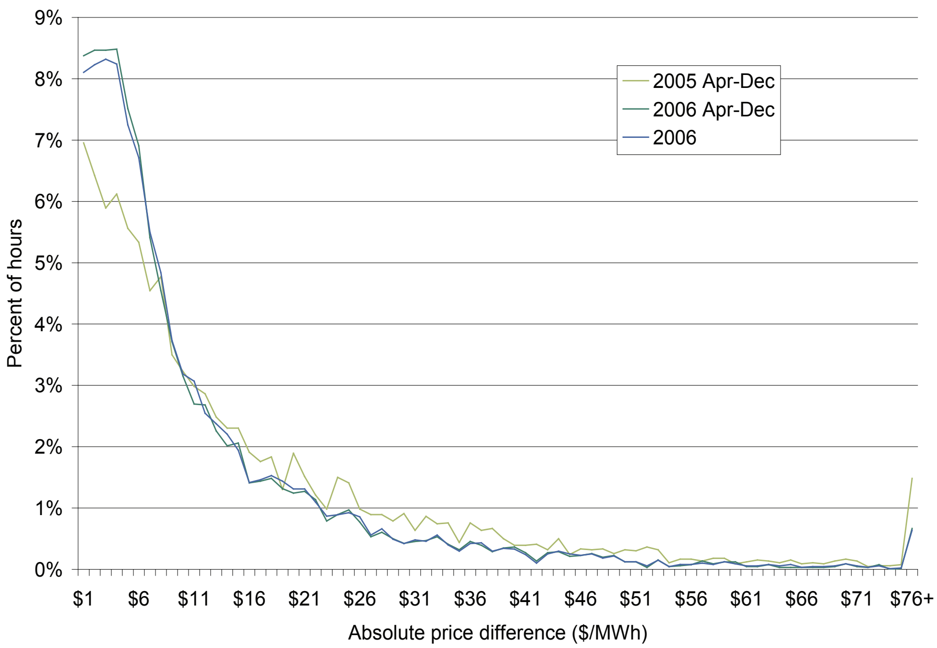
The RTOs responded that an appropriate cost-benefit analysis does not justify joint dispatch at the present time.[27] Nonetheless the RTOs recognize that there are actions that can be taken to address the lack of convergence of shadow prices. While shadow prices are internally consistent, when one RTO has no redispatch options, shadow prices in that RTO do not reflect the redispatch options of the other RTO. The RTOs are developing an approach to improve shadow price convergence. The RTOs believe that benefits can be achieved via less costly initiatives and that only after these are implemented and their impact assessed should incremental costs and benefits of joint dispatch be considered.

Figure 4-20 shows the hourly absolute differences between the MISO/PJM and PJM/MISO border prices. Three time periods are displayed in the figure including April to December 2005 (Midwest ISO market operation in 2005), the same period for 2006 and the full year, 2006. The curves show a shift to lower differences in both 2006 time periods when compared to the 2005 period.

26 WPS Complaint Requesting a MISO/PJM Joint and Common Market, Complaint, Docket No. EL06-97 (August 15, 2006).

27 Answer of the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., Response, Docket No. EL06-97 (September 15, 2006).

Figure 4-20 Absolute LMP difference of PJM and MISO border prices



Ramp Reservation Rule Change

PJM limits the amount of change in net interchange within 15-minute intervals in order to ensure compliance with NERC performance standards. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. The change in net interchange is referred to as ramp. Any market participant wishing to initiate (or change) a transaction must obtain a ramp reservation. PJM issues reservations, on a first come, first served basis, up to the ramp limit.

While ramp limits may be modified by PJM depending on system conditions, the limit is generally +/- 1,000 MW. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15-minute period would not exceed 1,000 MW in either direction.

Market participants at times request and receive ramp reservations that are not actually used for an energy transaction. When this happens, other market participants can be prevented from obtaining ramp reservations. In addition, the sudden, last-minute cancellation of large transactions can create significant impacts on PJM operations and markets as internal PJM resources have to make up any difference between actual and expected energy in PJM. This behavior (reserving but not using ramp) can reflect attempts to manipulate PJM prices, attempts to disadvantage competitors, mistakes by participants or the unanticipated failure to complete the underlying transaction. To help ensure efficient use of available ramp, PJM's former rules forced unused ramp reservations to expire 30 minutes before they were scheduled to flow if they were not backed up with an actual energy transaction. That left only 10 minutes for another participant to assemble a transaction and request the ramp because PJM rules required that transactions be submitted only up to 20 minutes prior to the scheduled start time for hourly transactions.[28] Given that it requires time to assemble the components of a transaction, the rule freed unused ramp when it was frequently too late for other market participants to make effective use of it. In other words, ramp reservations became available with too little time for others to use them and therefore did not prevent participants from effectively blocking other participants from the market.

In early 2006 the number of market participant complaints regarding this inability to obtain ramp in a timely manner and complaints about large ramp volume swings became more persistent. Ramp reservations were expiring unused at an increasing rate. (See Figure 4-21.) The MMU's effort to identify and contact participants resulted in improved behavior, but similar efforts in the past, while achieving the desired results, had only temporary effects. As a result, and as contemplated in the *2005 State of the Market Report*, the MMU developed, PJM proposed, and the membership agreed, to changes in the ramp reservation rules to impose limits on the time that a ramp reservation could be held without an associated energy schedule. These changes became effective on August 7, 2006.

Figure 4-21 Number of PJM automatic ramp reservation denials by month: January 2005 to July 2006

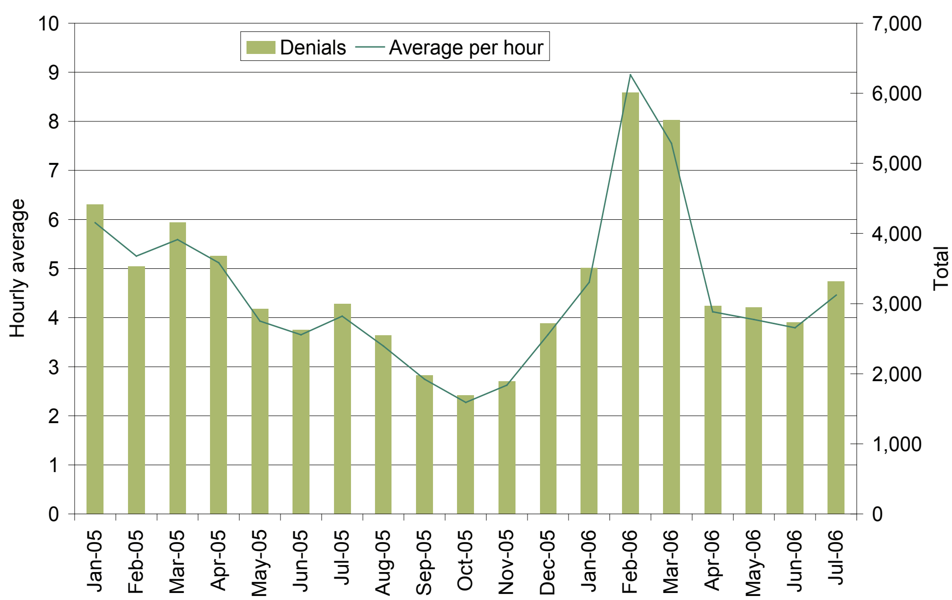


Figure 4-22 shows the results of the rule change. Under the new rule, ramp reservations expire (unless used) at the conclusion of a defined time interval that starts when a reservation is approved. This results in a distributed pattern of expirations in the time before the deadline for scheduling a transaction (20 minutes prior to flow). The actual distribution pattern of expirations since the rule change is shown in Figure 4-22.

28 See PJM "Manual 11: Scheduling Operations" (August 11, 2006), p. 103 (Accessed January 8, 2007) <http://www.pjm.com/contributions/pjm-manuals/pdf/m11.pdf > (823 KB).

For reference, Figure 4-22 also indicates when reservations would have expired under the old rule. Previously, all unused reservations expired at the same time, 30 minutes prior to flow. The distributed nature of automatic expirations under the new rule allows participants to obtain expired reservations in a more timely manner than was previously possible.

Figure 4-22 Distribution of expired ramp reservations in the hour prior to flow [old rules (theoretical) and new rules (actual)]: October to December 2006

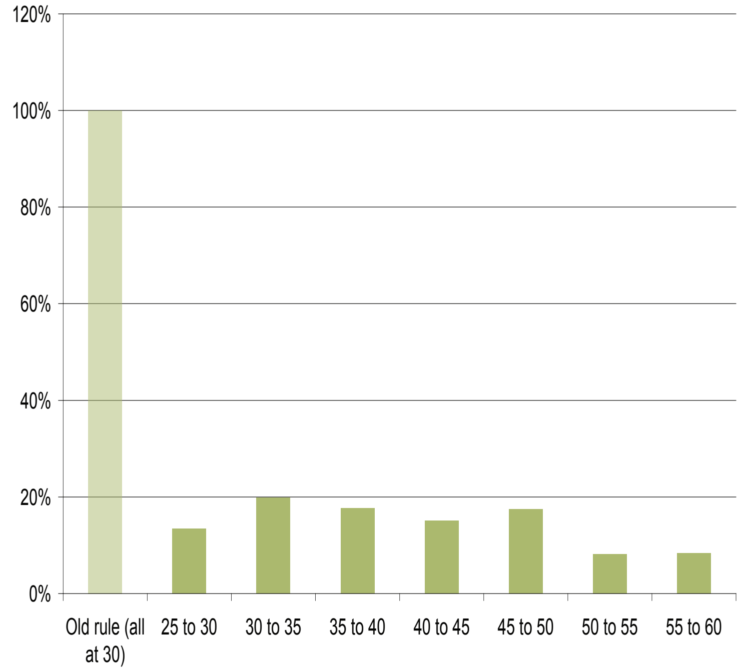


Figure 4-23 presents an actual example of how the old rule worked. These data are for flow to start at 1000 hours on April 19, 2006. Figure 4-24 takes the same data and applies the new rule. As seen in the oval highlighted area of Figure 4-23, 10 reservations were all automatically denied at the same time (0930) and one was withdrawn at the last minute (0929) by the market participant. At 0918 export ramp became unavailable. The import and export ramp were impacted by the volumes held in each reservation and export ramp was not available to other participants until 0930. In Figure 4-24 the same reservation data are used, but the new rules are applied. With the new rules, only one reservation was denied at 30 minutes prior to flow compared to the group of reservations denied under the old rule. Each of the other remaining 10 reservations was, as would have happened under the old rule, denied under the new rules. However under the new rules the denials occurred at the end of their individual wait periods rather than simultaneously at 30 minutes prior to flow. This had the effect of freeing up ramp sooner and with less volatility than would have been the case under the old rule. Note that at 0918, a time of high reservation activity, export ramp became available in contrast to the prior case.

Figure 4-23 Partial ramp history for April 19, 2006, hour beginning 1900

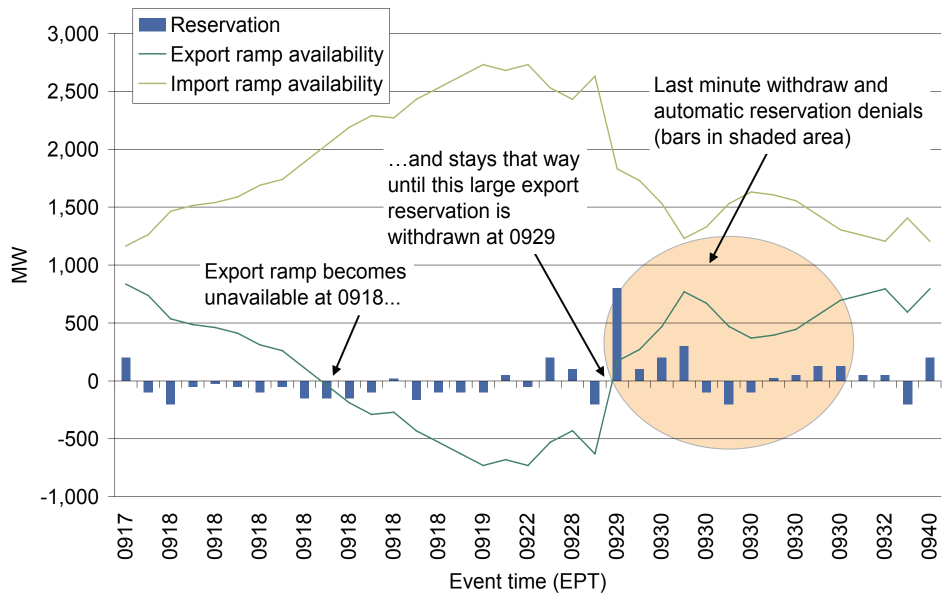
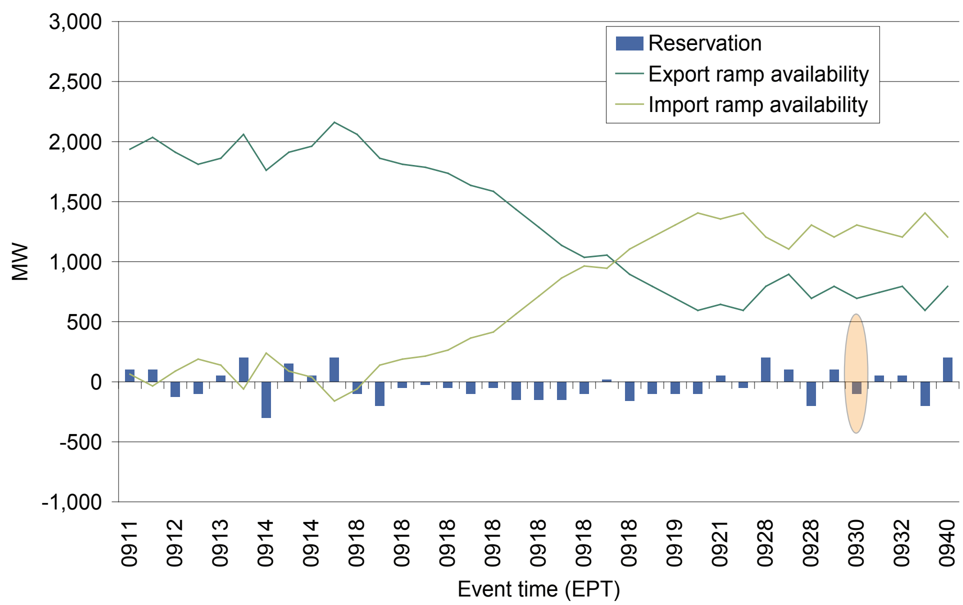


Figure 4-24 Partial ramp history for April 19, 2006, hour beginning 1900 modified to reflect theoretical application of new rule



When a reservation is made within 60 minutes of the time of flow, the new rule allows 10 minutes from the time the ramp reservation is approved for a participant to put a corresponding energy schedule into the system. If an energy schedule is not put into the system within that period, the ramp reservation is denied and the associated ramp is made available to others. This rule structure allows for unused ramp to become available to others in a more timely manner. Instead of large amounts of unused ramp becoming available at a fixed time (30 minutes prior to flow) with little time remaining to use it, unused ramp becomes available sooner and in a more evenly distributed manner.

After a reservation is made, if an energy schedule is not submitted in a timely manner, based on a sliding timescale ranging from 10 minutes to 90 minutes depending on how far in advance the request is made, the reservation is automatically denied. Table 4-8 shows these new timing requirements. Additionally, participants can now put their reservation request “in queue” if there is no ramp available at the time of their request. Reservations with the “in queue” status will be the first to receive any ramp that may become available and will be approved on a requested, timestamp basis.

Table 4-8 Timing requirements of new ramp reservation rule

	Pending Tag Reservations	
Reservation Duration	Time before Start of Reservation Submitted	Length of Time to Hold Reservation
<= 24 Hours	<= 1 Hour	10 Minutes
<= 24 Hours	> 1 Hour and < 4 Hours	15 Minutes
< 24 Hours	>= 4 Hours	90 Minutes
>= 24 Hours	Any Time	90 Minutes
	In-Queue Reservations	
Reservation Duration	Time before Start of Reservation Submitted	Maximum Length of Time in Queue
<=24 Hours	Any Time	Until 30 Minutes prior to the Start of the Reservation
> 24 Hours	Any Time	Until 5 Hours prior to the Start of the Reservation

While the implemented rule change has had a positive effect, the MMU will continue to monitor the reservations and use of ramp. There are also additional issues associated with ramp that remain to be addressed. As an example, PJM rules permit the potential artificial creation of ramp room in one direction using a ramp reservation in the opposite direction of that desired. For example, a market participant who wishes to initiate an import transaction when there is no available import ramp, requests a ramp reservation in the exporting direction. When accepted, this reservation creates apparent import ramp. The participant would also request an import reservation. Ultimately, the import transaction would flow and the export reservation would not be used to export energy, expiring after its time limit.