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. The external regions include both market and non market balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Market.** In contrast to the period from 2004 through late 2008, PJM was a net importer of energy in the Real-Time Market during January, February, March and May of 2009, and a net exporter of energy during April and June. In the Real-Time Market, monthly net interchange averaged 253 GWh.[1] Gross monthly import volumes averaged 3,924 GWh while gross monthly exports averaged 3,671 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market.** During the first six months of 2009, PJM was a net exporter of energy in the Day-Ahead Market in all months. The Day-Ahead monthly net interchange averaged -772 GWh. Gross monthly import volumes averaged 3,945 GWh while gross monthly exports averaged 4,717 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** During the first six months of 2009, gross imports in the Day-Ahead Energy Market were 99 percent of the Real-Time Market's gross imports (90 percent for the calendar year 2008) while gross exports in the Day-Ahead Market were 128 percent of the Real-Time Market's gross exports (106 percent for the calendar year 2008).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market, during the first six months of 2009, there were net exports at 12 of PJM's 20 interfaces. The top four net exporting interfaces in the Real-Time Market accounted for 69 percent of the total net exports: PJM/Neptune (NEPT) with 26 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 19 percent, PJM/Carolina Power and Light-East (CPLE) with 12 percent and PJM/First Energy (FE) with 12 percent of the net export volume. Eight PJM interfaces had net imports, with two importing interfaces accounting for 77 percent of the net import volume: PJM/Ohio Valley Electric Corporation (OVEC) with 57 percent and PJM/Michigan Electric Coordinated System (MECS) with 20 percent.

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, there were net exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces accounted for 62 percent of the total net exports, PJM/western Alliant Energy Corporation (ALTW) with 26 percent, PJM/eastern Alliant Energy Corporation (ALTE) with 19 percent and PJM/NEPTUNE (NEPT) with 17 percent. There were net imports in the Day-Ahead Market at eight of PJM's 20 interfaces. The top three importing interfaces accounted for 76 percent of the total net imports, PJM/OVEC with 49 percent, PJM/Michigan Electric Coordinated System (MECS) with 16 percent and PJM/Tennessee Valley Authority (TVA) with 11 percent.

- **Neptune Underwater Transmission Line to Long Island, New York.** On July 1, 2007, a 65-mile direct current (DC) transmission line from Sayreville, New Jersey, to Nassau County on Long Island, including undersea and underground cable, was placed in service. This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bi-directional, but in the first six months of 2009, power flows were only from PJM to New York. The average hourly flow during the first six months of 2009 was -549 MW.

1 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.

Interactions with Bordering Areas

- **PJM Interface Pricing with Organized Markets.**
  - **PJM and Midwest ISO Interface Pricing.** During the first six months of 2009, 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 the first six months of 2009, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus reflected economic fundamentals, as did the relationship between interface price differentials and power flows between PJM and NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and NYISO.
  - **PJM TLRs.** During the first six months of 2009, PJM issued 90 transmission loading relief procedures (TLRs). This represents an increase of 48 percent from the same time period in 2008 (61 during the first six months of 2008). The increase in TLR activity in 2009 was primarily attributed to a single low load pocket in northern Illinois, where excess generation in that area, during the off-peak hours, created excessive flows on nearby low voltage transmission lines. The need to continue to call TLRs for this overload was alleviated by the development of a new PJM dispatcher operating procedure that was implemented in early May of 2009.
- **Operating Agreements with Bordering Areas.**
  - **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[2] On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering. While the JOA does not include provisions for market-based congestion management or other market-to-market activity, at the request of PJM, PJM and the NYISO began discussion of a market-based congestion management protocol.
  - **PJM and Midwest ISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during the first six months of 2009. The market-based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[3]

    In 2009, the Midwest ISO requested that PJM review the components of the CMP to verify data accuracy. During this review, it was found that some data inputs to the market flow calculator were incorrect. The result of the errors in input data created inaccuracies in the market flow calculation, which resulted in smaller net settlements from PJM to the Midwest ISO as determined in the JOA. While the errors in input data have been corrected for market to market activity moving forward, the Midwest ISO and PJM are currently in the process of calculating the extent of any miscalculations.
  - **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[4] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management 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 the first six months of 2009.
  - **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[5] 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 the first six months of 2009. As part of this agreement, both parties

2 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

3 See PJM. "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (November 1, 2007) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,534 KB).

4 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2007) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

5 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2.98 MB).

agreed to develop a formal CMP. During the first six months of 2009, PEC and PJM continued discussions on more granular interface pricing as well as the development of the CMP.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[6] On May 23, 2007, PJM and VACAR South (VACAR is a subregion within the NERC Southeastern Electric Reliability Council (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During the first six months of 2009, PJM continued to operate under the terms of the operating protocol developed in 2005.[7]

Interchange Transaction Issues

- **Up-To Congestion.** In 2008, market participants requested that PJM increase the maximum value for up-to congestion offers, and to also allow negative offers for these transactions. PJM expressed concerns regarding the mismatch between up-to congestion transactions in the Day-Ahead Market and real-time transactions.[8] In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity. Increasing the offer cap, and allowing negative offers, could potentially increase the cleared volume of up-to congestion transactions, and aggravate the issue.

  On February 21, 2008, the MRC approved PJM's proposed resolution to the request for implementation on March 1, 2008.[9] The proposal allowed for an increased offer cap from $25 to ± $50, and explicitly allowed for negative offers. PJM also eliminated certain available sources and sinks in an effort to address the mismatches between the Day-Ahead and Real-Time Markets.

  The Market Monitoring Unit (MMU) recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

- **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 3.1 percent in the first six months of 2009, greater differences existed at 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 it had in 2008, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-7,563 GWh during the first six months of 2009 and -14,014 GWh during the calendar year 2008), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (1,827 GWh during the first six months of 2009 and 4,065 GWh during the calendar year 2008), although these mismatches have declined since the consolidation of the former PJM southeast and southwest pricing points in October 2006. 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.

6 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed July 6, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

7 111 FERC ¶ 61,228 (2005).

8 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed July 6, 2009) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221-item-03-up-to-congestion-transactions.ashx> (38KB).

9 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed July 6, 2009) <http://www.pjm.com/Media/committees-groups/committees/mrc/20080221-minutes.pdf > (61KB).

- **Loop Flows at PJM's Southern Interfaces.** The improvement in the 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) observed in late 2006, 2007 and during 2008 was sustained during the first six months of 2009. These improvements followed the changes from the Southeast and Southwest interface pricing points to the SOUTHIMP and SOUTHEXP interface pricing points that occurred on October 1, 2006.

- **Loop Flows at PJM's Northern Interfaces.** In 2008, new loop flows were created when pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows. Market participants scheduled transactions on a path from the NYISO to PJM through Ontario's Independent Electricity System Operator (IESO) and Midwest ISO systems, rather than reflecting the actual power flows which were primarily directly from NYISO to PJM. The participants faced a price incentive to engage in this behavior. When export transactions were scheduled from NYISO to Ontario, participants paid the lower export price at NYISO's Ontario interface rather than the higher export price at NYISO's PJM interface. The export price differences were more than enough to cover the cost of transmission through Ontario and MISO into PJM. When the export transactions were approved in the NYISO hourly market, the NYISO committed additional generation to support the transactions. The actual flow of energy that resulted was primarily directly from NYISO to PJM across the PJM/NYISO Interface. PJM's interface pricing calculations correctly reflected the actual power flows, but NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

- **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.

  The MMU recommends that PJM and the Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would provide the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impact data, actual flowgate flow data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

Additional Interchange Transaction Analysis

- **Net Interchange Fluctuation.** Figure 4-3 shows that PJM had been a net exporter of energy in the Real-Time Market during the period from 2004 through 2008. During this period, maximum exports occurred during the third quarter of the year (July, August and September) and minimum exports occurred during the first half of the year. As shown in Figure 4-1, PJM's net interchange during the first six months of 2009 fluctuated between net imports and net exports. In January, February and March, PJM was a net importer of energy. In April, PJM became a net exporter of energy, but a net importer in May and a net exporter in June. This fluctuation can be partially attributed to seasonal variations, generation availability and interface pricing mechanisms.

  Historically, PJM has exported more energy in the summer months than in the winter months. The seasonal decrease in exports during

January, February and March contributed to PJM being a net importer in those months.

In addition to the seasonal variability, interface pricing mechanisms also had an effect on the overall net interchange. Figure 4-17 and Figure 4-18 show the real-time interchange volume and the corresponding average hourly LMP available for Duke Energy Carolinas and Progress Energy Carolinas. In January, when the interface price was the highest, both Duke and Progress had the largest amount of imports into PJM. Imports appear clearly related to the interface price while the relationship is less clear for exports. The interface pricing method for Duke and Progress was modified in 2009.

- **Interface Pricing Agreements with Individual Companies.** PJM entered into confidential locational interface pricing agreements with Duke Energy Carolinas, Progress Energy Carolinas and North Carolina Municipal Power Agency (NCMPA) in 2007 that provided more advantageous pricing to these companies than the applicable interface pricing rules. Each of these agreements established a locational price for purchases and sales between PJM and the individual company that applied under specified conditions. There were a number of issues with these agreements including that they were not made public until specifically requested by the MMU, that the pricing was not available to other participants in similar circumstances, that the pricing was not designed to reflect actual power flows, that the pricing did not reflect full security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate and in 2008 provided the required notification to terminate the agreements. The agreements were terminated on February 1, 2009.

  In addition to terminating the agreements, PJM worked through the stakeholder process to develop a revision to the tariff that would enhance the method for calculating interface pricing with all neighboring balancing authorities that wish to take advantage of the more granular interface pricing. The new interface pricing methodology includes three options. The first option is to continue using the SouthImp and SouthExp pricing points. While the SouthImp and SouthExp pricing points reflect the physical flows into and out of PJM, the interface encompasses a large geographic area, and individual neighboring balancing authorities may benefit from providing additional data to take advantage of a more granular pricing mechanism. The second option is the “high/low” option. To utilize the “high/low” option, PJM must be able to verify the source for import transactions and the sink for export transactions. Under this option, PJM uses the highest generator bus LMP for exports from PJM and the lowest generator bus LMP for imports into PJM. In addition, unit level telemetry can be provided that shows the real-time unit status. When a generator is not running, the “high/low” method eliminates that bus LMP from the determination of the import or export price. The third option is the “marginal cost proxy method”. The “marginal cost proxy method” requires the submittal of generator cost data to PJM. This pricing method is based on the incremental production cost of the marginal generator of the external supplier. The marginal generator is based on the incremental production cost to supply load in the external area, supported by real-time metered output data. For imports to PJM, if the LMP at the unit, calculated by PJM with reference to PJM generation and load, is greater than or equal to the production cost for each unit on line then the interface price is equal to the PJM calculated bus LMP of the marginal unit. If the LMP is less than the production cost for any unit on line, then the interface price is equal to the lowest PJM calculated LMP of any such units. For exports from PJM, if the LMP is greater than or equal to the production cost for each unit on line then the interface price is equal to the PJM calculated LMP of the marginal production unit. If the LMP is greater than the production cost for any unit on line, then the interface price is equal to the highest PJM calculated LMP for any such units. The “marginal cost proxy method” falls short of a full congestion management agreement.

  The proposed tariff revisions were filed with FERC on December 2, 2008[10], and approved on May 1, 2009.[11] As a condition of the approval, the Commission required that PJM establish procedures to negotiate, in good faith, a congestion management agreement (which is necessary for eligibility to continue the “high/low” and “marginal cost proxy” pricing beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[12] As of July 1, 2009, each of Duke Energy Carolinas, Progress Energy Carolinas and the North Carolina Municipal Power Agency was in the process of negotiating a congestion management agreement with PJM.

  As of July 1, 2009, due to the required software modifications to support the proposed tariff revisions, neither the “high/low” nor the “marginal cost proxy method” options were implemented. Figure 4-17 through Figure 4-20 show the real-time and day-ahead prices for imports and exports

10 PJM Interconnection, L.L.C., Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008).
11 PJM Interconnection, L.L.C., Letter Order, Docket No. ER09-369-000 (May 1, 2009).
12 127 FERC ¶ 61,101.

applicable for the interface pricing under the various agreements. During the period from February 1 through May 3, 2009, the interface pricing is based on the SouthIMP and SouthEXP LMPs as there were no agreements in place.

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its Joint Operating Agreement (JOA) with Midwest ISO to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[13] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result of the rule, requests for service sometimes exceeded the amount of service available to customers. Unlike non-firm point-to-point WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The new spot import rules provided incentives to hoard spot import capability. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the reservations queued time intraday, and at 5:00 EPT when queued the day prior. On June 23, PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage has been 100 percent, compared to 70 percent prior to the modification. (See Figure 4-21). The MMU will continue to monitor participant use of spot import service.

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. 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 transparent, least cost, security constrained economic dispatch for all available generation. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are nontransparent.

The MMU analyzed the transactions between PJM and neighboring balancing authorities for the first six months of 2009, including evolving transaction patterns, economics and issues. During the first six months of 2009, PJM was a net importer of energy and a large share of both import and export activity occurred at a small number of interfaces. Four interfaces accounted for 69 percent of the total real-time net exports and two interfaces accounted for 77 percent of the real-time net import volume. Three interfaces accounted for 62 percent of the total day-ahead net exports and three interfaces accounted for 76 percent of the day-ahead net import volume.

In order to manage interactions with other market areas, PJM has entered into formal agreements with a number of balancing authorities. 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. However, more needs to be done to assure that market signals are used to manage constraints affecting interarea transactions. PJM and NYISO, as neighboring market areas, should develop market-based congestion management protocols as soon as practicable. In addition, PJM should continue its efforts to gain access to the data required to understand loop flows in real-time and to ensure that responsible parties pay their appropriate share of the costs of redispatch.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other balancing authorities 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 for specific units 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 balancing authorities to help ensure that transactions are free to respond to

13 See "WPC White Paper" (April 20, 2007) (Accessed July 6, 2008) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

market signals and to reduce the ability to game or hoard ramp. PJM also entered into agreements with specific balancing authorities for separate interface pricing that have been questioned with respect to transparency and equal access. PJM needs to ensure that such pricing is transparent and that all participants have access to the defined pricing when in the same position.

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 balancing authorities. PJM attempts to manage loop flows by creating interface prices that reflect the actual power flows, regardless of contract path. 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 continue not to be fully understood 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, shed light on the interactions among market and non market areas and permit market based congestion management across the Eastern Interconnection. 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. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

PJM needs to continue to pay careful attention to all the mechanisms used to manage flows at the interfaces between PJM and surrounding areas. PJM manages its interface with external areas, in part, through limitations on the amount of change in net interchange within 15-minute intervals. The change in net interchange is referred to as ramp. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. As a result of the fact that ramp is free but is a valuable resource, there are strong incentives to game the ramp rules. The same is true of spot import service. Up-to congestion service is a market option used to import power to or export power from PJM which can create mismatches between transactions in the Day-Ahead Energy Market and the Real-Time Energy Market that result in inaccurate pricing and can provide a gaming opportunity.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through June 2009 (See 2008 SOM, Figure 4-1)

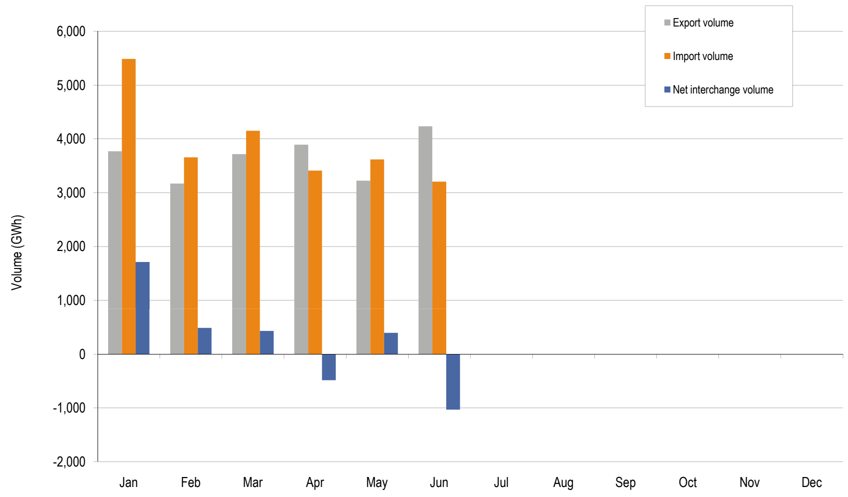


Figure 4-2 PJM day-ahead scheduled imports and exports: January through June 2009 (See 2008 SOM, Figure 4-2)

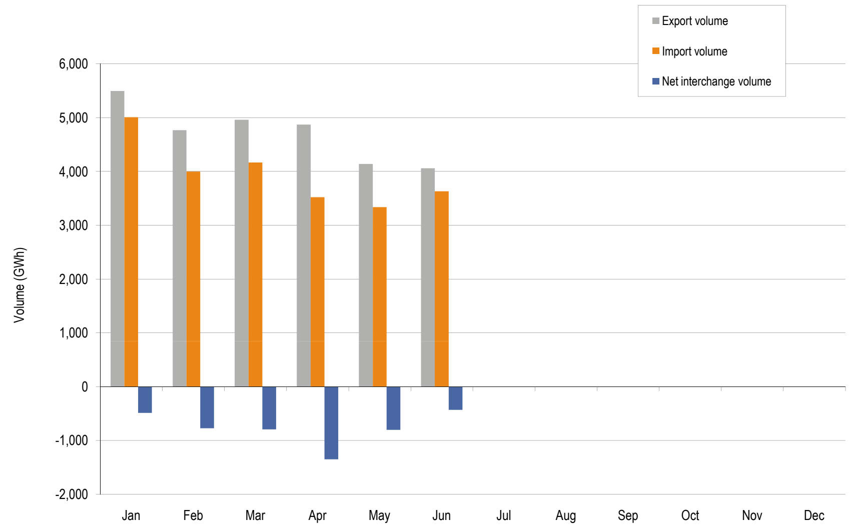
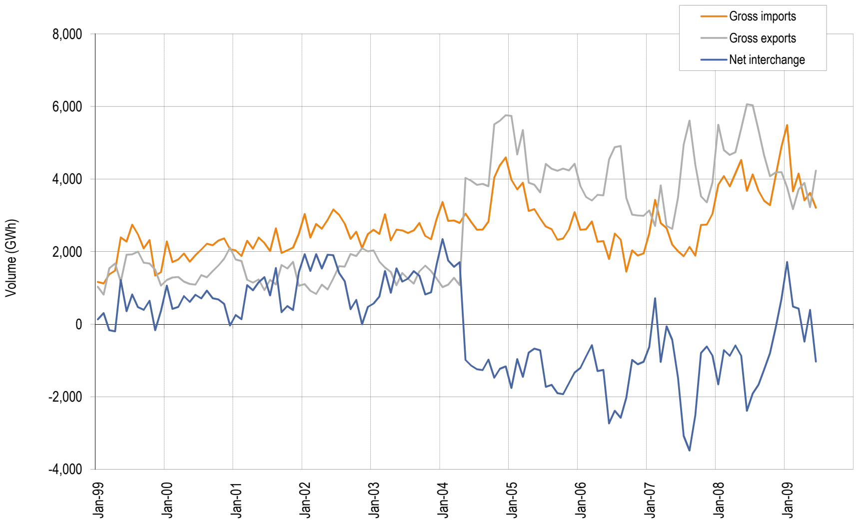


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through June 2009 (See 2008 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-1)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	44.4	(41.8)	(86.5)	(147.3)	(117.6)	(143.6)	(492.4)
ALTW	(65.6)	(69.6)	(74.3)	(97.5)	(66.4)	(175.3)	(548.7)
AMIL	126.2	23.7	8.7	(14.9)	28.0	(24.0)	147.7
CIN	102.6	(96.1)	(179.7)	(216.6)	14.7	(91.8)	(466.9)
CPLE	(62.7)	(161.8)	(208.1)	(281.1)	(113.8)	(293.2)	(1,120.7)
CPLW	(71.4)	(67.4)	(74.3)	(72.0)	(60.3)	(69.8)	(415.2)
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.7
DUK	622.7	67.8	89.9	10.6	60.9	(86.0)	765.9
EKPC	(173.5)	(78.8)	(88.6)	(57.4)	67.3	(9.7)	(340.7)
FE	(215.6)	(221.5)	(166.6)	(204.3)	(178.6)	(93.1)	(1,079.7)
IPL	47.1	(17.5)	(88.6)	(79.8)	101.5	(23.9)	(61.2)
LGEE	137.4	90.7	176.3	101.4	169.8	32.6	708.2
MEC	150.4	302.1	146.1	155.1	(148.4)	(239.8)	365.5
MECS	421.7	361.8	552.3	60.9	341.6	398.7	2,137.0
NEPT	(294.8)	(402.5)	(445.1)	(400.9)	(434.5)	(456.9)	(2,434.7)
NIPS	(8.2)	(51.5)	(35.5)	(60.0)	(3.9)	(38.1)	(197.2)
NYIS	(396.1)	(231.7)	(253.3)	(180.8)	(265.5)	(466.0)	(1,793.4)
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	6,162.0
TVA	244.0	128.7	167.6	35.2	69.3	(160.0)	484.8
WEC	(64.6)	(41.0)	(26.5)	(44.9)	(38.3)	(86.3)	(301.6)
Total	1,715.3	487.8	432.9	(481.8)	396.2	(1,031.0)	1,519.4

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-2)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	170.4	65.4	18.2	1.7	0.1	0.1	255.9
ALTW	45.7	22.2	1.7	0.0	1.9	3.5	75.0
AMIL	147.3	44.9	38.3	26.8	62.2	48.6	368.1
CIN	382.9	265.0	335.2	209.3	256.2	335.3	1,783.9
CPLE	223.9	69.4	66.8	39.9	115.1	16.8	531.9
CPLW	2.1	0.0	0.0	0.0	0.0	0.0	2.1
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.7
DUK	737.8	277.9	209.5	154.1	239.2	151.2	1,769.7
EKPC	2.7	6.1	12.9	2.5	90.3	33.2	147.7
FE	60.5	32.6	101.6	60.8	73.0	160.0	488.5
IPL	107.5	43.8	51.9	63.5	148.6	65.7	481.0
LGEE	187.4	125.2	183.6	125.8	172.0	55.7	849.7
MEC	337.6	428.2	371.7	361.2	77.8	26.5	1,603.0
MECS	573.5	500.4	679.7	264.3	458.0	486.8	2,962.7
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	32.5	8.1	0.5	0.0	11.0	0.0	52.1
NYIS	1,004.4	589.8	829.7	982.3	795.2	791.0	4,992.4
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	6,162.0
TVA	292.8	185.1	214.2	107.1	146.2	31.4	976.8
WEC	8.7	1.2	17.8	0.6	4.4	5.8	38.5
Total	5,489.0	3,659.5	4,152.4	3,412.4	3,621.6	3,206.8	23,541.7

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-3)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	126.0	107.2	104.7	149.0	117.7	143.7	748.3
ALTW	111.3	91.8	76.0	97.5	68.3	178.8	623.7
AMIL	21.1	21.2	29.6	41.7	34.2	72.6	220.4
CIN	280.3	361.1	514.9	425.9	241.5	427.1	2,250.8
CPLE	286.6	231.2	274.9	321.0	228.9	310.0	1,652.6
CPLW	73.5	67.4	74.3	72.0	60.3	69.8	417.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	115.1	210.1	119.6	143.5	178.3	237.2	1,003.8
EKPC	176.2	84.9	101.5	59.9	23.0	42.9	488.4
FE	276.1	254.1	268.2	265.1	251.6	253.1	1,568.2
IPL	60.4	61.3	140.5	143.3	47.1	89.6	542.2
LGEE	50.0	34.5	7.3	24.4	2.2	23.1	141.5
MEC	187.2	126.1	225.6	206.1	226.2	266.3	1,237.5
MECS	151.8	138.6	127.4	203.4	116.4	88.1	825.7
NEPT	294.8	402.5	445.1	400.9	434.5	456.9	2,434.7
NIPS	40.7	59.6	36.0	60.0	14.9	38.1	249.3
NYIS	1,400.5	821.5	1,083.0	1,163.1	1,060.7	1,257.0	6,785.8
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	48.8	56.4	46.6	71.9	76.9	191.4	492.0
WEC	73.3	42.2	44.3	45.5	42.7	92.1	340.1
Total	3,773.7	3,171.7	3,719.5	3,894.2	3,225.4	4,237.8	22,022.3

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-4)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	(142.2)	(61.4)	(518.5)	(673.0)	(779.1)	(521.6)	(2,695.8)
ALTW	(722.6)	(756.0)	(604.5)	(746.7)	(389.5)	(497.7)	(3,717.0)
AMIL	52.8	72.3	42.2	86.6	102.4	261.6	617.9
CIN	(225.4)	(96.3)	(47.8)	57.5	(36.7)	55.7	(293.0)
CPLE	49.1	(23.0)	(86.0)	(81.0)	(88.1)	(157.1)	(386.1)
CPLW	(176.6)	(166.0)	(184.5)	(180.0)	(155.9)	(176.2)	(1,039.2)
CWLP	(0.7)	(0.1)	0.0	0.0	0.0	0.0	(0.8)
DUK	255.9	26.4	1.1	22.3	120.9	58.7	485.4
EKPC	(31.1)	(22.8)	(1.1)	0.0	0.0	0.0	(55.0)
FE	(206.7)	(233.8)	(241.4)	(197.3)	(206.0)	(116.4)	(1,201.6)
IPL	(316.7)	(191.0)	(157.2)	(67.1)	85.2	143.0	(503.8)
LGEE	(16.5)	(8.9)	23.5	6.9	9.7	39.9	54.6
MEC	27.3	(90.0)	(173.4)	(185.3)	(209.3)	(252.9)	(883.6)
MECS	101.9	172.9	250.4	261.1	370.6	433.8	1,590.7
NEPT	(326.4)	(403.8)	(446.4)	(402.1)	(436.6)	(472.3)	(2,487.6)
NIPS	(233.7)	(320.9)	(71.3)	(194.6)	(286.2)	(62.2)	(1,168.9)
NYIS	158.7	146.5	130.8	7.5	(1.8)	(8.2)	433.4
OVEC	835.6	743.5	786.0	738.6	824.2	857.3	4,785.2
TVA	482.5	384.6	151.7	81.8	5.4	(42.8)	1,063.2
WEC	(52.5)	57.0	352.4	117.2	269.0	28.7	771.8
Total	(487.2)	(770.8)	(794.0)	(1,347.6)	(801.8)	(428.7)	(4,630.1)

Table 4-5 Day-ahead gross import volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-5)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	675.2	674.4	470.1	173.7	52.2	106.5	2,152.1
ALTW	190.8	183.6	33.2	2.3	0.0	12.5	422.4
AMIL	59.4	75.0	44.5	91.5	105.0	261.6	637.0
CIN	103.2	159.2	178.5	247.6	190.5	320.2	1,199.2
CPLE	187.6	75.8	14.4	21.0	24.0	7.8	330.6
CPLW	9.5	2.1	0.6	0.0	2.8	0.0	15.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	291.9	102.7	55.9	71.4	138.8	90.0	750.7
EKPC	0.8	0.0	0.0	0.0	0.0	0.0	0.8
FE	15.2	44.9	60.0	23.0	10.3	100.7	254.1
IPL	246.5	159.9	153.2	254.2	258.7	250.0	1,322.5
LGEE	2.9	0.2	24.9	8.1	11.4	41.0	88.5
MEC	173.2	0.0	0.0	0.0	0.0	0.0	173.2
MECS	504.9	400.1	488.5	606.8	631.9	626.5	3,258.7
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	284.5	248.4	490.5	208.0	135.6	151.4	1,518.4
NYIS	890.3	584.5	776.0	776.4	612.0	675.0	4,314.2
OVEC	866.7	766.6	810.5	763.1	828.4	858.2	4,893.5
TVA	496.4	407.2	172.8	104.0	20.2	12.0	1,212.6
WEC	11.2	113.8	393.7	172.7	316.2	118.3	1,125.9
Total	5,010.2	3,998.4	4,167.3	3,524.0	3,338.0	3,631.7	23,669.6

Table 4-6 Day-ahead gross export volume by interface (GWh): January through June 2009 (See 2008 SOM, Table 4-6)

	Jan	Feb	Mar	Apr	May	Jun	Total
ALTE	817.4	735.8	988.6	846.7	831.3	628.1	4,847.9
ALTW	913.4	939.6	637.7	749.0	389.5	510.2	4,139.4
AMIL	6.6	2.7	2.3	4.9	2.6	0.0	19.1
CIN	328.6	255.5	226.3	190.1	227.2	264.5	1,492.2
CPLE	138.5	98.8	100.4	102.0	112.1	164.9	716.7
CPLW	186.1	168.1	185.1	180.0	158.7	176.2	1,054.2
CWLP	0.7	0.1	0.0	0.0	0.0	0.0	0.8
DUK	36.0	76.3	54.8	49.1	17.9	31.3	265.3
EKPC	31.9	22.8	1.1	0.0	0.0	0.0	55.8
FE	221.9	278.7	301.4	220.3	216.3	217.1	1,455.8
IPL	563.2	350.9	310.4	321.3	173.5	107.0	1,826.3
LGEE	19.4	9.1	1.4	1.2	1.7	1.1	33.9
MEC	145.9	90.0	173.4	185.3	209.3	252.9	1,056.8
MECS	403.0	227.2	238.1	345.8	261.3	192.7	1,668.0
NEPT	326.4	403.8	446.4	402.1	436.6	472.3	2,487.6
NIPS	518.2	569.3	561.8	402.6	421.8	213.6	2,687.3
NYIS	731.6	438.0	645.2	768.9	613.8	683.2	3,880.8
OVEC	31.1	23.1	24.5	24.5	4.2	0.9	108.3
TVA	13.9	22.6	21.1	22.2	14.8	54.8	149.4
WEC	63.7	56.8	41.3	55.5	47.2	89.6	354.1
Total	5,497.4	4,769.2	4,961.3	4,871.6	4,139.8	4,060.4	28,299.7

Interface Pricing

Table 4-7 Active interfaces: January through June 2009 (See 2008 SOM, Table 4-7)

	Jan	Feb	Mar	Apr	May	Jun
ALTE	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active

Figure 4-4 PJM's footprint and its external interfaces (See 2008 SOM, Figure 4-4)

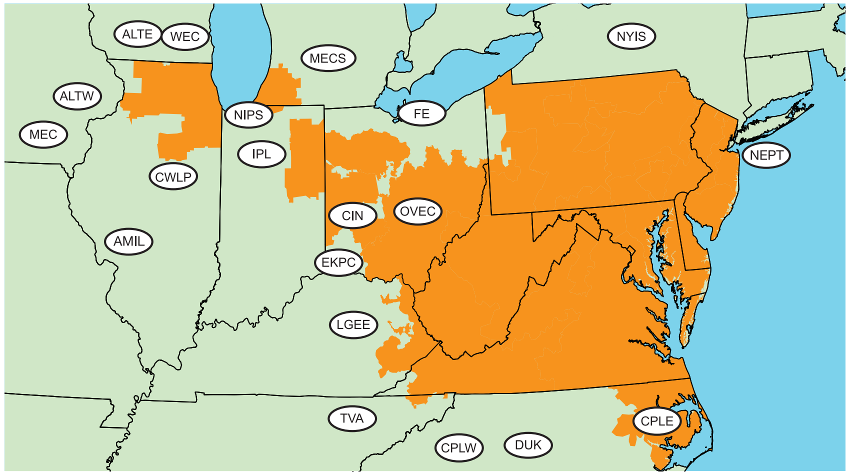


Table 4-8 Active pricing points: January through June 2009 (See 2008 SOM, Table 4-8)

PJM 2009 (Jan - Jun) Pricing Points				
MICHFE	MISO	NEPT	NIPSCO	Northwest
NYIS	Ontario IESO	OVEC	SOUTHEXP	SOUTHIMP

Interactions with Bordering Areas

PJM and Midwest ISO Interface Prices

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): January through June 2009 (See 2008 SOM, Figure 4-5)

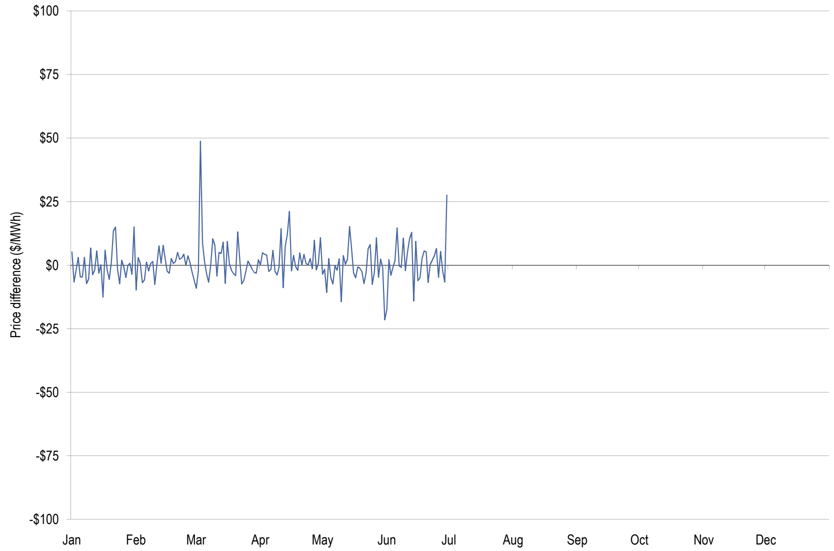


Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through June 2009 (See 2008 SOM, Figure 4-6)

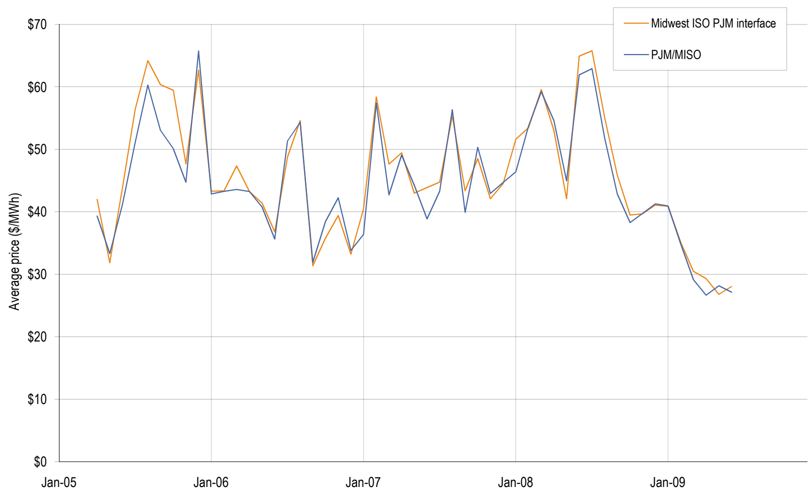


Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): January 1, 2006, through June 30, 2009 (See 2008 SOM, Table 4-9)

	2006	2007 (Pre-Marginal Losses)	2007 (Post-Marginal Losses)	2008	2009 (Jan - Jun)
Kincaid (PJM) & Coffeen (MISO)	$5.87	$4.31	$5.76	$8.26	$6.22
Beaver Valley (PJM) & Mansfield (MISO)	$2.28	($2.64)	$0.55	$0.89	$3.67
Miami Fort (PJM) & (MISO)	$1.95	($1.30)	($0.95)	$1.25	$2.60
Stuart (PJM) & (MISO)	$2.09	($0.81)	($0.64)	$0.85	$2.23
PJM/MISO Interface	($0.23)	($1.83)	($0.85)	($0.76)	($0.61)

Figure 4-7 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): January through June 2009 (New Figure)

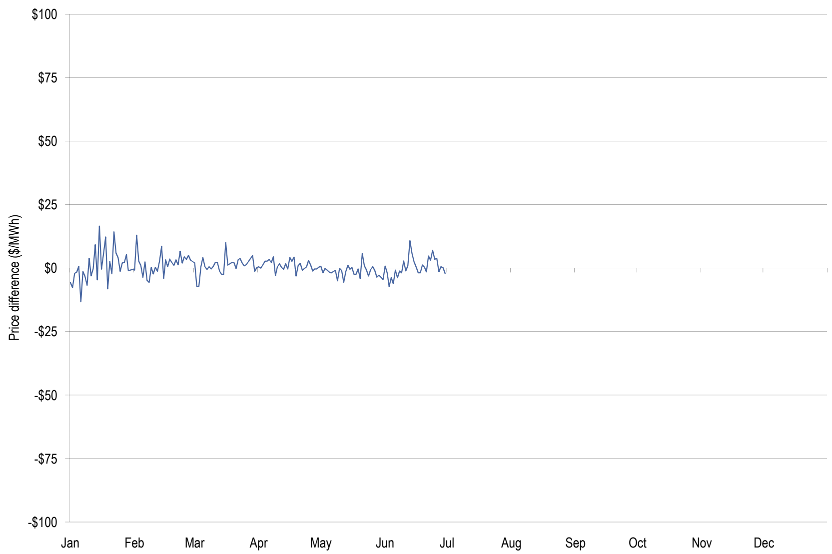


Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through June 2009 (New Figure)

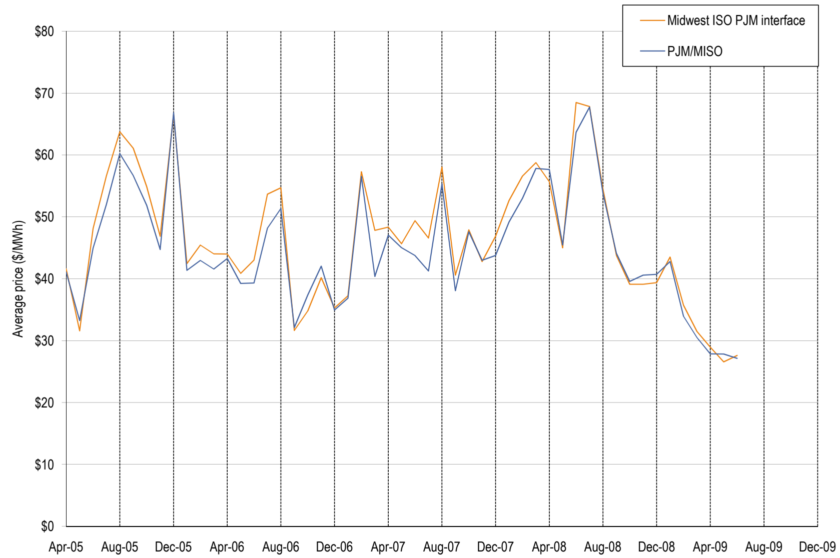


Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): January through June 2009 (New Table)

	2009 (Jan - Jun)
Kincaid (PJM) & Coffeen (MISO)	$5.59
Beaver Valley (PJM) & Mansfield (MISO)	$2.48
Miami Fort (PJM) & (MISO)	$2.36
Stuart (PJM) & (MISO)	$1.93
PJM/MISO Interface	($0.60)

PJM and NYISO Interface Prices

Figure 4-9 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): January through June 2009 (See 2008 SOM, Figure 4-7)

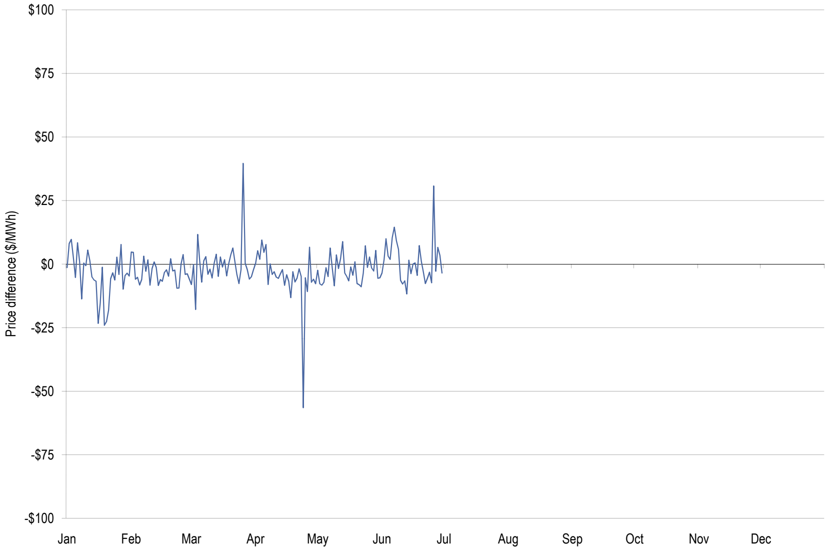


Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through June 2009 (See 2008 SOM, Figure 4-8)

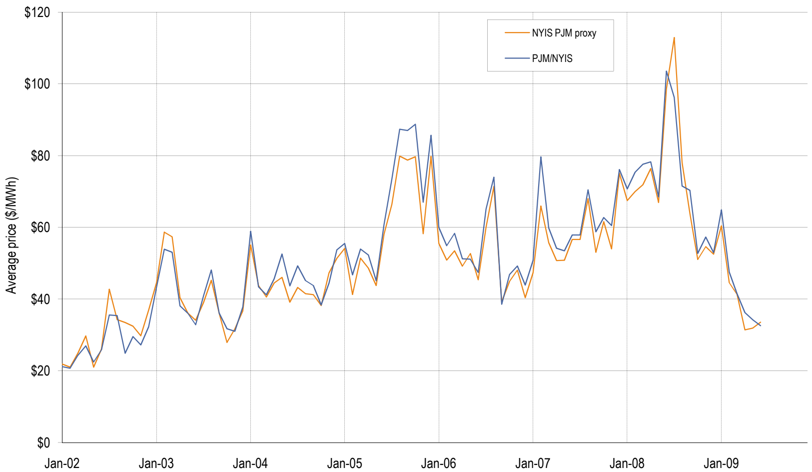


Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through June 2009 (New Figure)

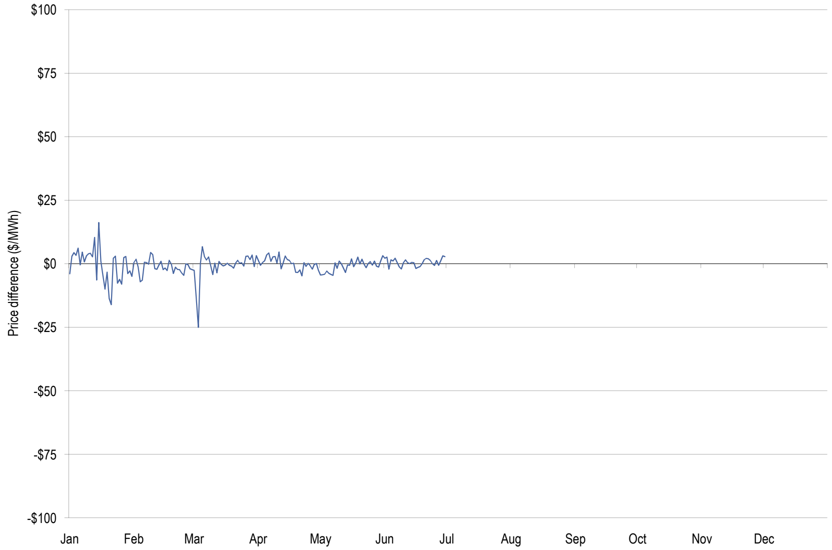
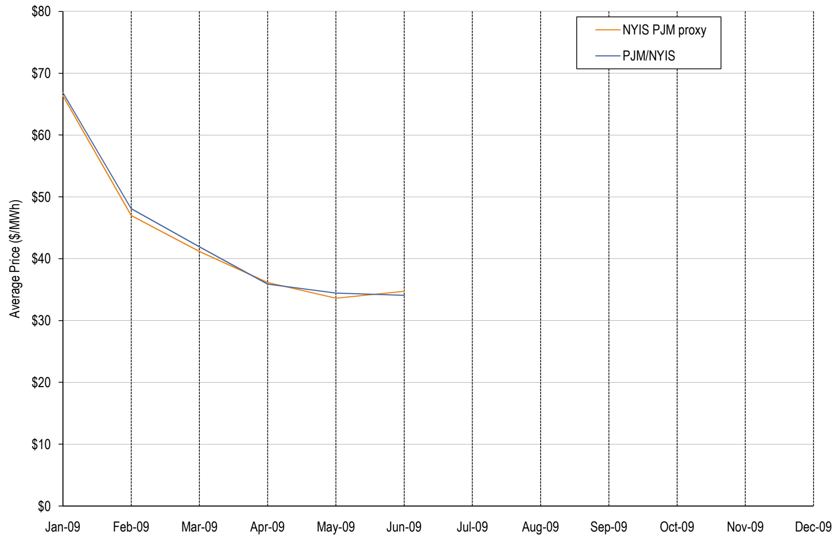


Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January through June 2009 (New Figure)



Summary of Interface Prices between PJM and Organized Markets

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: January through June 2009 (See 2008 SOM, Figure 4-9)

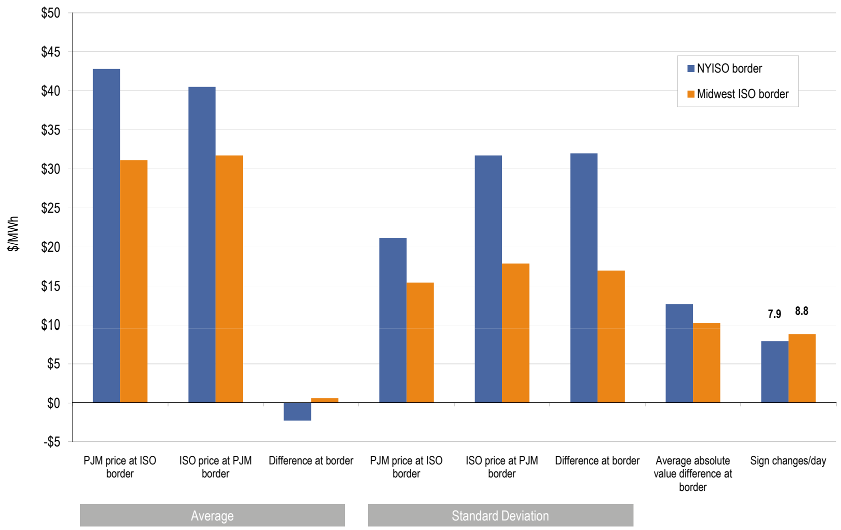
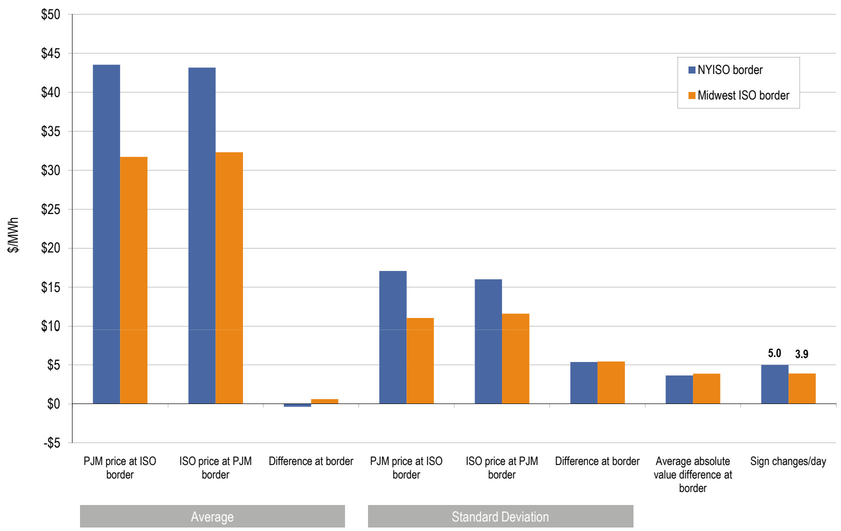


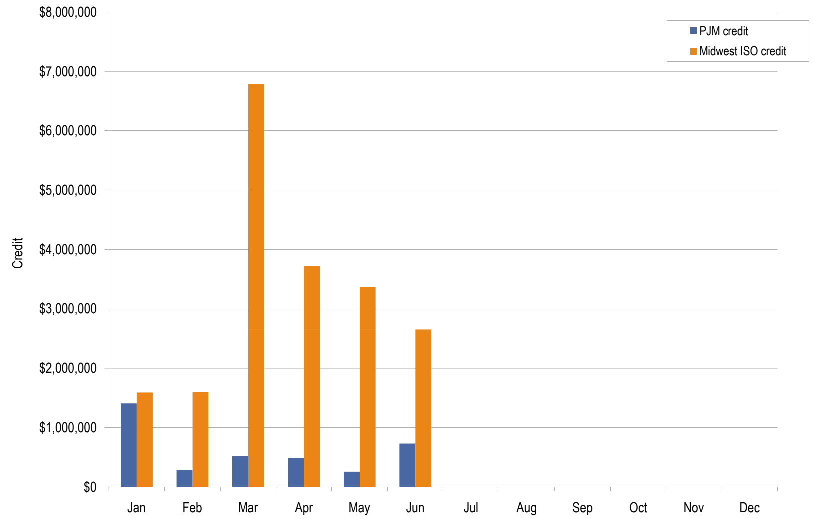
Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: January through June 2009 (New Figure)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement (JOA)

Figure 4-15 Credits for coordinated congestion management: January through June 2009 (See 2008 SOM, Figure 4-10)



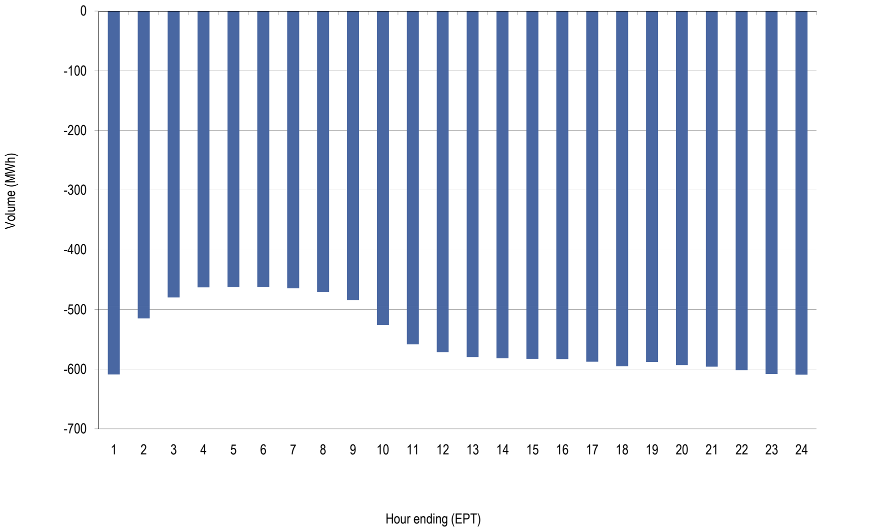
Con Edison and PSE&G Wheeling Contracts

Table 4-11 Con Edison and PSE&G wheeling settlement data: January through June 2009 (See 2008 SOM, Table 4-10)

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total Congestion Credit	$919,769	$1,900	$921,669	$2,962,871	$0	$2,962,871
Congestion Credit			$864,388			$2,978,822
Adjustments			$484,182			$11,879
Net Charge			($426,901)			($27,830)

Neptune Underwater Transmission Line to Long Island, New York

Figure 4-16 Neptune hourly average flow: January through June 2009 (See 2008 SOM, Figure 4-11)



Interface Pricing Agreements with Individual Companies

Table 4-12 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (See 2008 SOM, Table 4-11)

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$50.58	$47.29	$47.29	$3.29	$3.29
PEC	$52.21	$47.29	$47.29	$4.93	$4.93
NCMPA	$50.66	$47.29	$47.29	$3.37	$3.37

Table 4-13 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through June 2009 (See 2008 SOM, Table 4-11)

	IMPORT LMP	EXPORT LMP	SOUTH-IMP	SOUTH-EXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.58	$31.98	$30.92	$30.92	$0.66	$1.06
PEC	$31.94	$33.12	$30.92	$30.92	$1.02	$2.20
NCMPA	$31.79	$31.85	$30.92	$30.92	$0.87	$0.93

Figure 4-17 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2009 (New Figure)

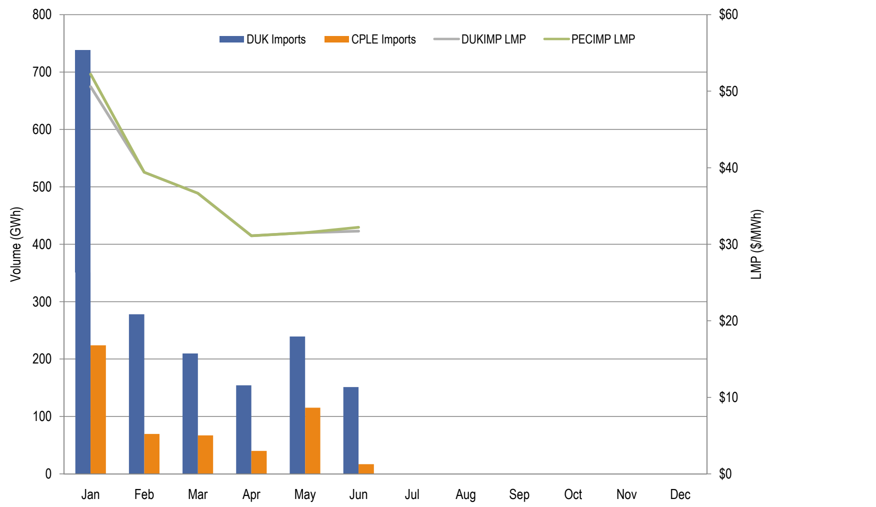


Figure 4-18 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2009 (New Figure)

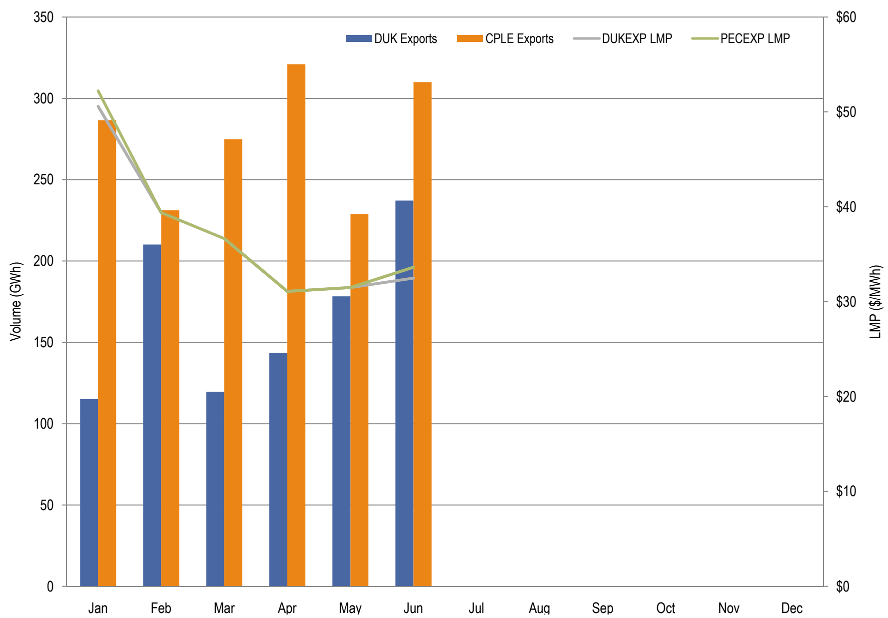


Table 4-14 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January 2009 (New Table)

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$52.01	$48.59	$48.59	$3.42	$3.42
PEC	$54.41	$48.59	$48.59	$5.82	$5.82
NCMPA	$52.10	$48.59	$48.59	$3.51	$3.51

Table 4-15 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through June 2009 (New Table)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.69	$32.49	$31.37	$31.37	$0.32	$1.12
PEC	$32.19	$33.64	$31.37	$31.37	$0.82	$2.27
NCMPA	$32.06	$32.13	$31.37	$31.37	$0.69	$0.76

Figure 4-19 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2009 (New Figure)

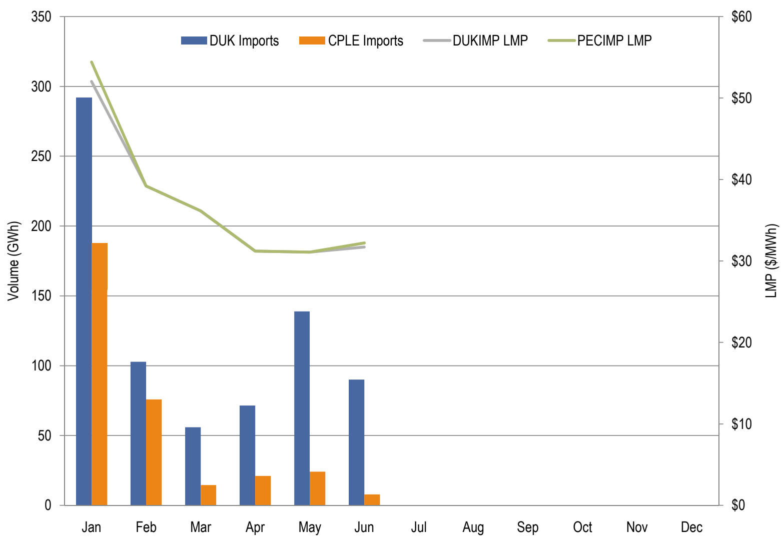
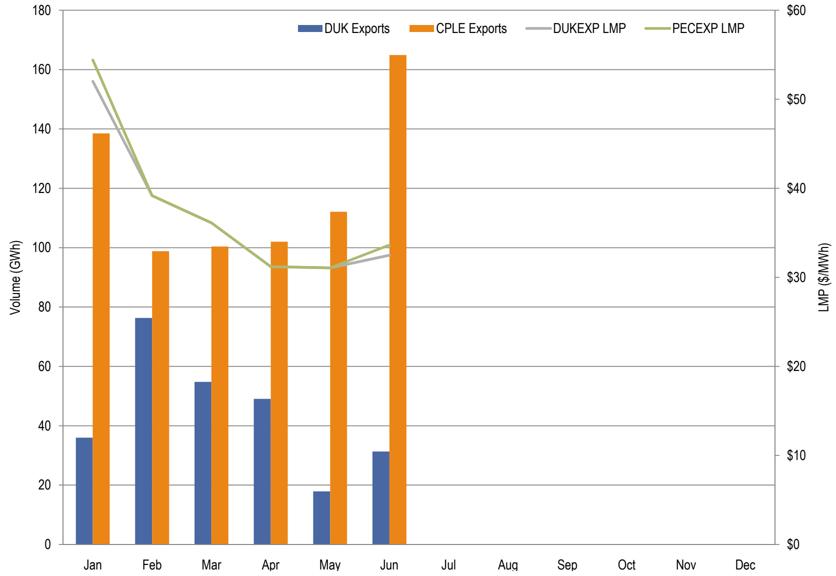


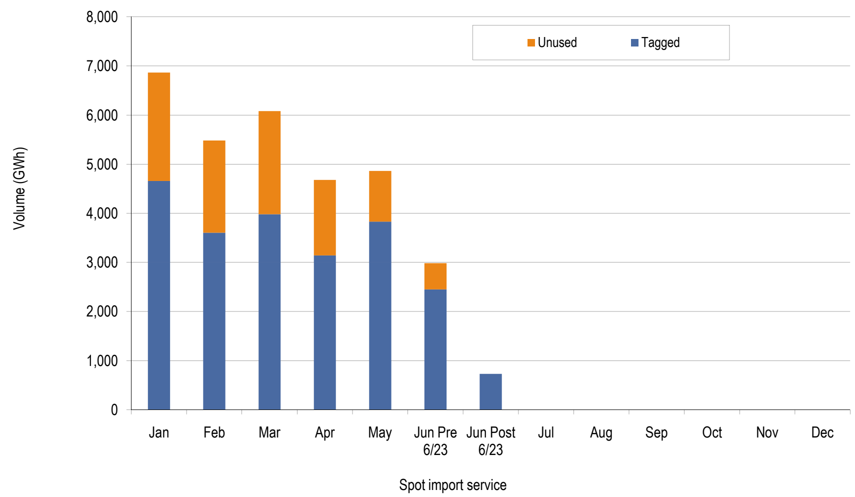
Figure 4-20 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2009 (New Figure)



Interchange Transaction Issues

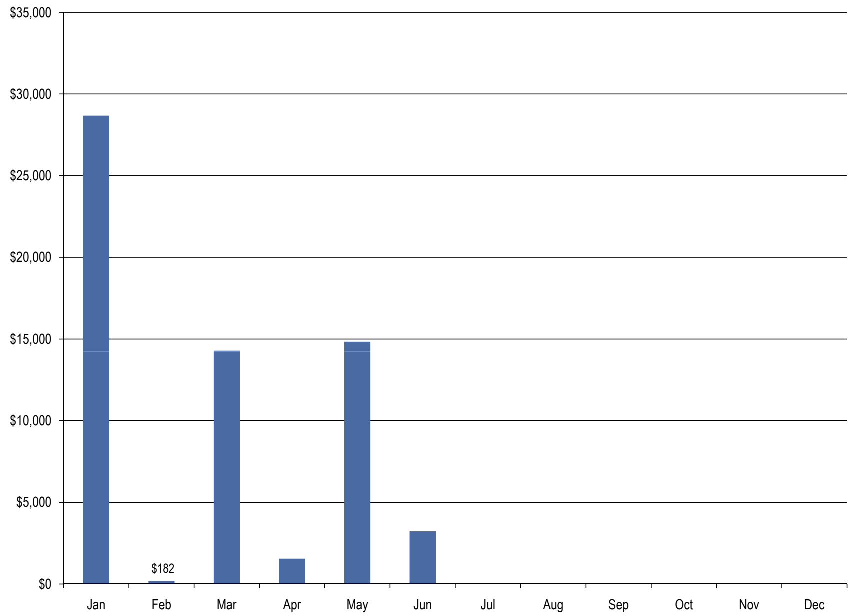
Spot Import

Figure 4-21 Spot import service utilization: January through June 2009 (See 2008 SOM, Figure 4-12)



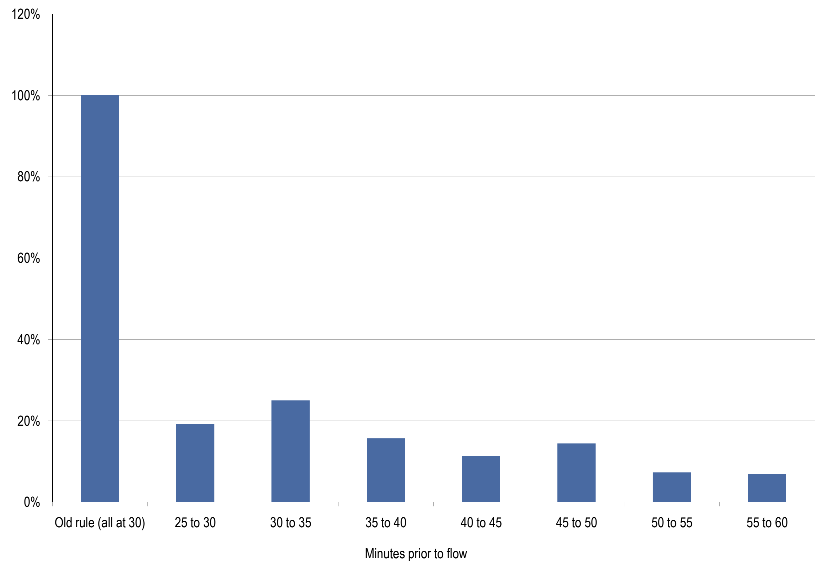
Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-22 Monthly uncollected congestion charges: January through June 2009 (See 2008 SOM, Figure 4-13)



Ramp Availability

Figure 4-23 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through June 2009 (See 2008 SOM, Figure 4-14)



Curtailment of Transactions

TLRs

Figure 4-24 PJM and Midwest ISO TLR procedures: Calendar year 2008 and January through June 2009 (See 2008 SOM, Figure 4-15)

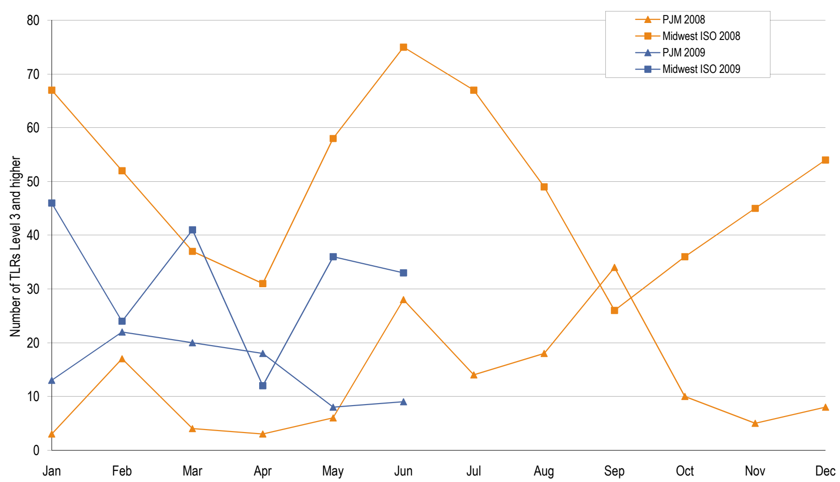


Figure 4-25 Number of different PJM flowgates that experienced TLRs: Calendar year 2008 and January through June 2009 (See 2008 SOM, Figure 4-16)

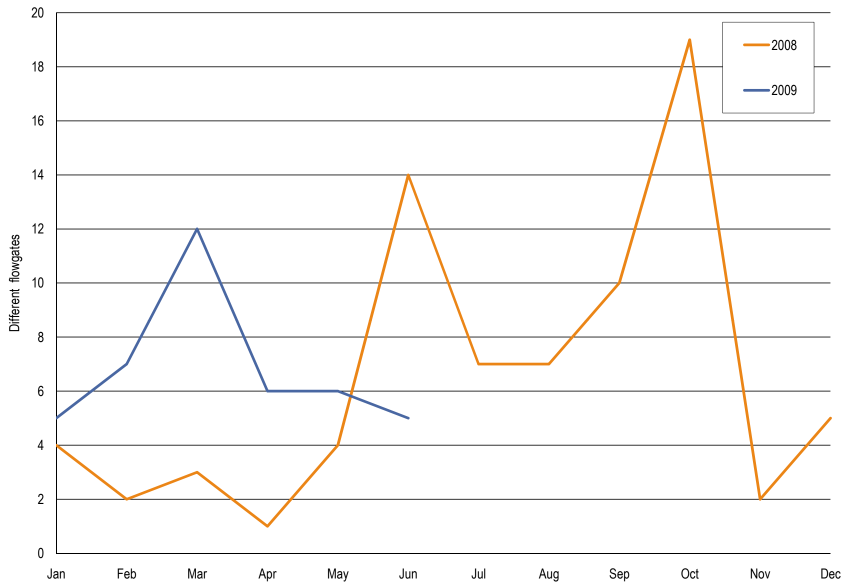
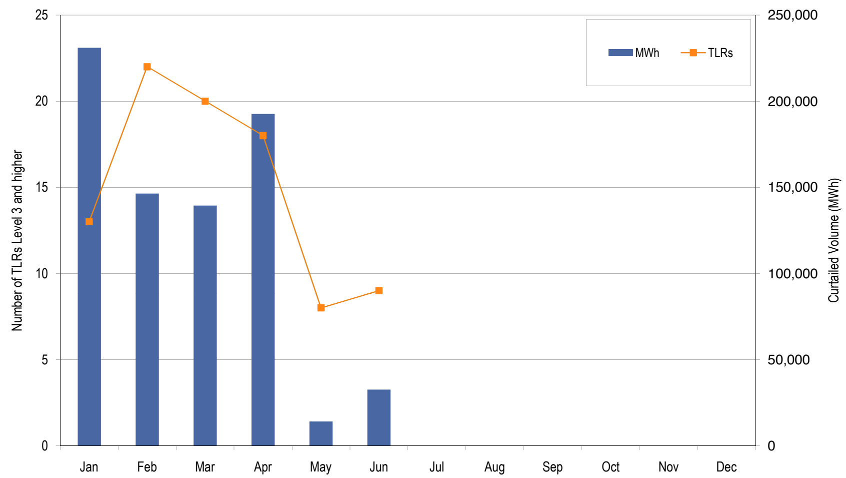
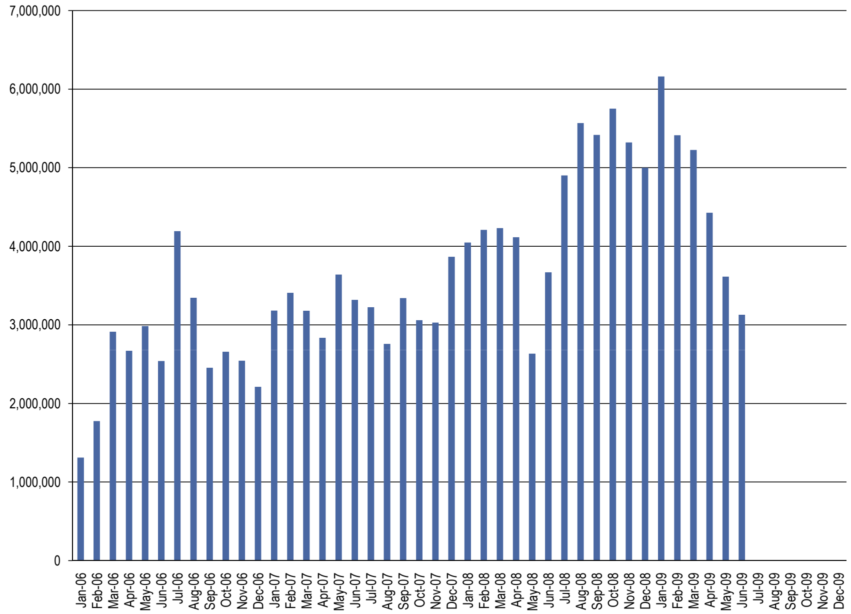


Figure 4-26 Number of PJM TLRs and curtailed volume: January through June 2009 (See 2008 SOM, Figure 4-17)



Up-To Congestion

Figure 4-27 Monthly up-to congestion bids in MWh: January 2006 through June 2009[14] (See 2008 SOM, Figure 4-18)



14 Prior MMU presentations to the Members Committee overstated the volume of up-to congestion bids.

Loop Flows

Table 4-16 Net scheduled and actual PJM interface flows (GWh): January through June 2009 (See 2008 SOM, Table 4-12)

Net scheduled and actual PJM interface flows: JAN - JUN 2009				Difference (percent of net scheduled)
	Actual	Net Scheduled	Difference (GMh)	
ALTE	(3,184)	(492)	(2,692)	547%
ALTW	(1,025)	(549)	(476)	87%
AMIL	4,830	106	4,724	4457%
CIN	1,027	(374)	1,401	(375%)
CPLE	3,882	(559)	4,441	(794%)
CPLW	(813)	(414)	(399)	96%
CWLP	(339)	-	(339)	0%
DUK	(994)	766	(1,760)	(230%)
EKPC	411	(341)	752	(221%)
FE	(999)	(1,463)	464	(32%)
IPL	1,165	(61)	1,226	(2010%)
LGEE	708	708	-	0%
MEC	(910)	369	(1,279)	(347%)
MECS	(5,426)	2,137	(7,563)	(354%)
NEPT	(2,385)	(2,385)	-	0%
NIPS	(1,332)	(197)	(1,135)	576%
NYIS	(1,000)	(1,904)	904	(47%)
OVEC	4,109	6,162	(2,053)	(33%)
TVA	2,312	485	1,827	377%
WEC	1,603	(302)	1,905	(631%)
YTD Total	1,640	1,692	(52)	(3.1%)

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

Figure 4-28 PJM/MECS Interface average actual minus scheduled volume: January through June 2009 (See 2008 SOM, Figure 4-19)

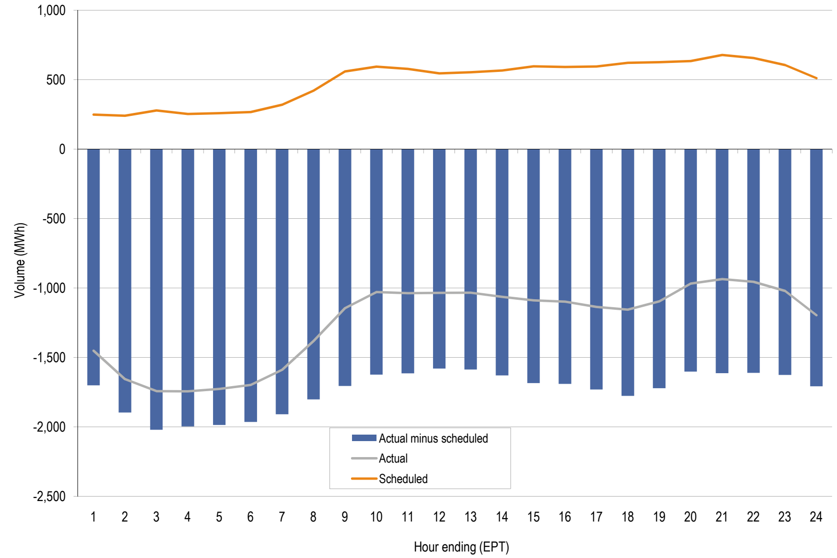


Figure 4-29 PJM/TVA average flows: January 1, through September 30, 2006, pre-consolidation (See 2008 SOM, Figure 4-20)

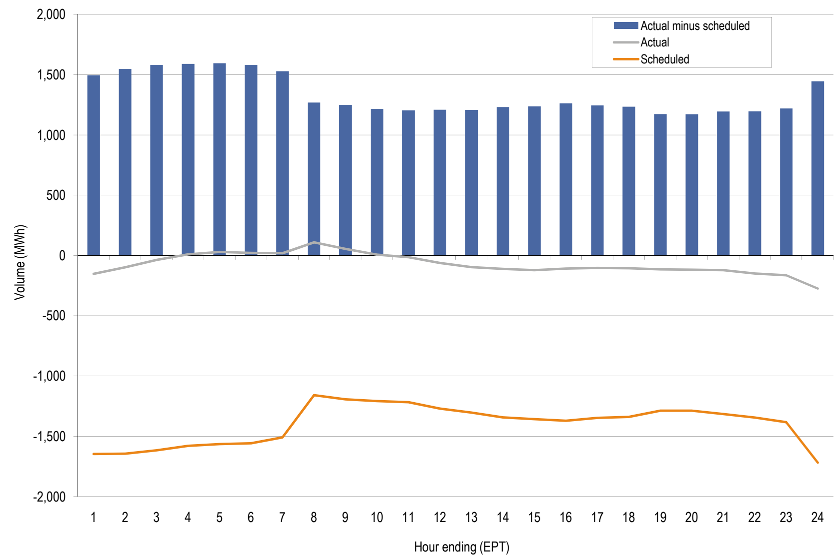


Figure 4-30 PJM/TVA average flows: January through June 2009 (See 2008 SOM, Figure 4-21)

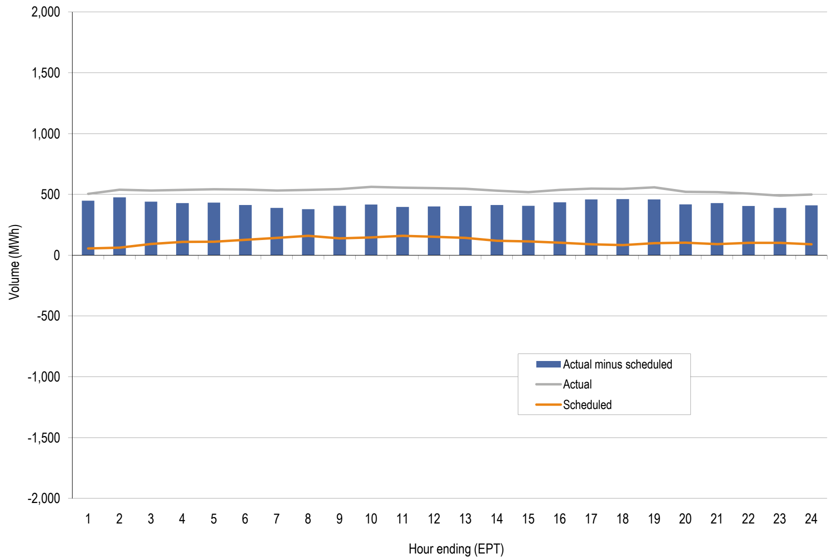
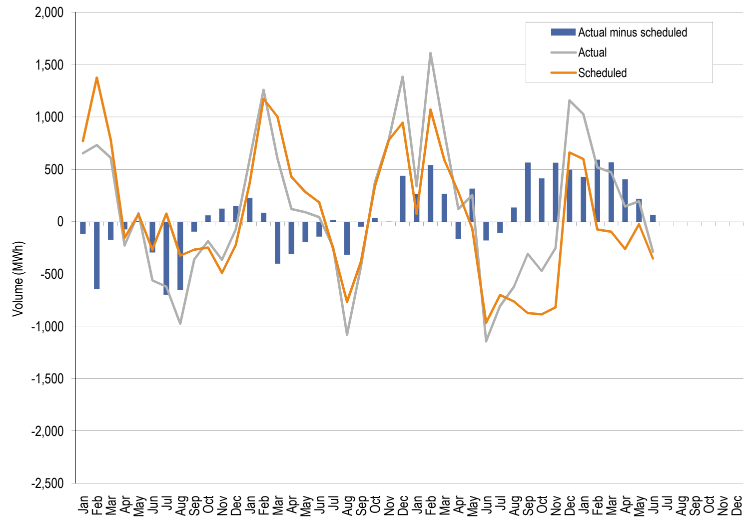


Figure 4-32 Southeast actual and scheduled flows: January 2006 through June 2009 (See 2008 SOM, Figure 4-23)



Loop Flows at PJM's Southern Interfaces

Figure 4-31 Southwest actual and scheduled flows: January 2006 through June 2009 (See 2008 SOM, Figure 4-22)