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.** PJM was a net importer of energy in the Real-Time Market in January, February, March and May of 2009, and a net exporter of energy in the remaining months. In the Real-Time Market, monthly net interchange averaged -117 GWh.[1] Gross monthly import volumes averaged 3,671 GWh while gross monthly exports averaged 3,788 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market.** PJM was a net importer of energy in the Day-Ahead Market in July, and a net exporter of energy in the remaining months. In the Day-Ahead Market, monthly net interchange averaged -753 GWh. Gross monthly import volumes averaged 4,073 GWh while gross monthly exports averaged 4,826 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** In 2009, gross imports in the Day-Ahead Energy Market were 111 percent of the Real-Time Market's gross imports (90 percent in 2008), gross exports in the Day-Ahead Market were 127 percent of the Real-Time Market's gross exports (106 percent in 2008) and net interchange in the Day-Ahead Energy Market was 642 percent of net interchange in the Real-Time Energy Market (-1,407 GWh in the Real-Time Market and -9,033 GWh in the Day-Ahead Market).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market in 2009, there were net exports at 12 of PJM's 21 interfaces.[2] The top three net exporting interfaces in the Real-Time Market accounted for 62 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 28 percent, PJM/Neptune (NEPT) with 25 percent and PJM/Carolina Power and Light-East (CPLE) with 9 percent of the net export volume. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 55 percent of the total net PJM exports in the Real-Time Market. Nine PJM interfaces had net imports, with two importing interfaces accounting for 88 percent of total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 68 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 14 of PJM's 21 interfaces. The top three net exporting interfaces accounted for 58 percent of the total net exports, PJM/western Alliant Energy Corporation (ALTW) with

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.
2 In September 2009, the Linden Variable Frequency Transformer (VFT) facility began testing. This facility is treated as a separate interface with PJM, bringing the total interfaces with PJM to 21.

24 percent, PJM/eastern Alliant Energy Corporation (ALTE) with 17 percent and PJM/Neptune (NEPT) with 17 percent. Seven PJM interfaces had net imports in the Day-Ahead Market, with three interfaces accounting for 85 percent of the total net imports: PJM/OVEC with 53 percent, PJM/Wisconsin Energy Corporation (WEC) with 18 percent and PJM/Michigan Electric Coordinated System (MECS) with 15 percent.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** During 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 Prices.** During 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 the NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and the NYISO.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[3] 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, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued into 2009. By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[4] After working in collaboration with PJM, the Midwest ISO and the Ontario Independent Electricity System Operator (IESO), including an opportunity to comment from their stakeholders and market monitors, the NYISO filed on January 12, 2010, a Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.[5]

- **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 2009. The market based congestion

3 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

4 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

5 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" (January 12, 2010) (Accessed January 25, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[6]

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 during the time period from April 2005 through June 2009. The resulting inaccuracies in the market flow calculation meant that the Midwest ISO received less compensation than appropriate. 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 shortfall. PJM reported an estimate of 77.5 million dollars.[7]

As of December 31, 2009, PJM and the Midwest ISO had not agreed upon a method to estimate the amount for the entire period. Differences have also emerged over how the parties are administering the JOA, such as the use by the Midwest ISO of proxy flowgates. This practice, if confirmed, measured and determined inconsistent with the JOA, would mean that the Midwest ISO received more compensation than appropriate. The parties are currently engaged in a confidential United States Federal Energy Regulatory Commission (FERC) mediated settlement process to resolve these issues.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[8] 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 2009.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[9] 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 2009. As part of this agreement, both parties agreed to develop a formal CMP. During 2009, PEC and PJM continued confidential 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.**[10] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region 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.

Other Agreements with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During 2009, PJM continued to operate under the terms of the operating protocol developed in 2005.[11]

6 See PJM. "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,294 KB).

7 See PJM. "PJM/MISO Market Flow Calculation Error"(September 10, 2009) (Accessed January 15, 2010) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

8 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

9 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2,983 KB).

10 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

11 111 FERC ¶ 61,228 (2005).

- **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, via undersea and underground cable, was placed in service, providing a direct connection from PJM to the New York Independent System Operator, Inc. (NYISO). This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[12] The average hourly flow for 2009 was -555 MW.

- **Linden Variable Frequency Transformer (VFT) Facility.** On November 1, 2009, the Linden VFT facility was placed in service, providing an additional direct connection from PJM to the NYISO. A variable frequency transformer allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle regulating transformer.[13] The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line, with a capacity of 300 MW. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[14] The average hourly flow for 2009 was -136 MW.[15]

Interchange Transaction Issues

- **Loop Flows.** Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. Loop flows arise from transactions 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 2.2 percent in 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 (-14,441 GWh during 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 (3,840 GWh during 2009 and 4,065 GWh during the calendar year 2008). 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.** 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) was significant during 2009.

12 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed January 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,403 KB).
13 A phase angle regulating transformer (PAR) allows dispatchers to change the flow of MW over a transmission line by changing the impedance of the transmission facility.
14 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed January 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,884 KB).
15 The average hourly flow reported for the Linden Variable Frequency Transformer includes the scheduled flow during the testing period that occurred starting in September 2009.

The southern interfaces have historically experienced significant loop flows.[16] A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP). At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. (The average difference between the Locational Marginal Price (LMP) at the Southeast pricing points and the SouthEXP pricing point was $2.61 in 2009 and the average difference between LMP at the Southwest pricing points and the SouthEXP pricing point was -$1.42 in 2009. In other words, it was more expensive to buy from PJM for export to the south under the old pricing for Southeast pricing point and less expensive to buy from PJM for export to the south under the old pricing for the Southwest pricing point.) These agreements remain in place. The MMU recommends that these agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match pricing with physical flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SWPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SWPP, through the Midwest ISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (the Midwest ISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incurring additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SWPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both the Midwest ISO border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows).

— **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.[17] PJM's interface pricing calculations correctly

16 See *2002 State of the Market Report*, Part 2, Section 3, "Interchange Transactions." (March 5, 2003) (Accessed January 19, 2010) <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2002/SOM2002-part2.pdf> (4,068 KB).

17 See the *2008 State of the Market Report for PJM*, Volume II, "Interchange Transactions."

reflected the actual power flows, but the 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 appropriately disregarded the scheduled path.

By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[18]

Consistent with the Commission's direction, during the third quarter of 2009, the NYISO convened the Broader Regional Markets group, which included representatives from PJM, the NYISO, the Midwest ISO and the IESO, to develop a solution to the northeastern loop flow issues. The group solicited comments from stakeholders and the market monitors. The MMU filed comments on November 13, 2009.[19]

The group developed several recommendations, including the use of phase angle regulators (PARs) to control energy flows, a buy-through congestion method, the development of a new tool, using existing functionality within the NERC Interchange Distribution Calculator (IDC), to visualize the loop flows and an interregional transaction coordination approach to align business rules across the northeast ISOs/RTOs. On January 12, 2010, in compliance with the Commission's directive, NYISO submitted its *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.*[20]

Engineering approaches to address loop flows, such as PARs and variable frequency transformers, are a means to help ameliorate loop flow issues, but they do not address the root cause of loop flows. So long as these physical solutions are used in conjunction with more comprehensive market solutions, the MMU supports cost effective investment in additional PARs for system control. With the possible exception of cost allocation issues, the use of PARs does not appear to be controversial. Engineering approaches should not serve as a basis to defer or deflect attention from the development of market solutions.

Implementing a buy-through congestion methodology is also unlikely to resolve the underlying pricing issue. PJM offers a similar product, where market participants are allowed to continue to flow their transactions when they would otherwise be curtailed by a transmission loading relief procedure (TLR), if they are willing to pay the congestion costs of their parallel flows affecting the PJM system. This product, called "TLR Buy-Through", was implemented in PJM in 2001. In the nearly eight years that PJM has offered this product, it has never been

18 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

19 See "IMM Comments on Draft Loop Flow Recommendations of the Broader Regional Markets"(November 13, 2009) (Accessed January 21, 2010) <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_Comments_on_Draft_Loop_Flow_Recommendations_20091113.pdf> (86 KB).

20 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" (January 12, 2010) (Accessed January 25, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

used by market participants. Instead, the transactions were curtailed in the TLR process to alleviate the loop flows.

The report also included a recommendation that the NYISO move to a less than hourly dispatch timeframe through interregional coordination. While this recommendation did not include details, redispatch on the quarter hour would allow NYISO market participants to respond more quickly to the NYISO pricing signals.

Parallel flow visualization will provide additional information to the reliability coordinators, and will also assign a non-firm generation to load component to congestion within non-market areas. The MMU supports this project, as it will provide additional details and archived data to better analyze loop flows. However, the work of the Broader Regional Market group and the continued development of this tool within the North American Electric Reliability Corporation (NERC)/North American Energy Standards Board (NAESB) arena do not require linkage. It would be more productive to focus on direct solutions to loop flow issues rather than the already ongoing development of loosely related industry tools.

Faulty market rules, which provided incentives to market participants to schedule energy on paths inconsistent with the physical flows, were responsible for the loop flows that motivated the NYISO's initial filing in this proceeding. The solution to this problem should start with and give priority to appropriate interface pricing that reflects the actual flow of energy. Although the buy-through congestion approach also attempts to address this issue, a more cost effective solution would assign interface prices based on the Generation Control Area (GCA) for imports and Load Control Area (LCA) for exports, as designated on the NERC e-Tag. This method for interface pricing has been used by PJM and the Midwest ISO for several years, and could be implemented immediately by other RTOs/ISOs at minimal cost.

The MMU recommends that a change in the interface pricing methodology be addressed directly. The MMU recommends that the parties consider the uniform adoption of a GCA to LCA pricing methodology, similar to that used by PJM, to set transaction prices based on the actual flow of energy from source to sink. With the appropriate pricing, the incentive for market participants to schedule around specific RTOs/ISOs would be eliminated.

— **Data Required for Full Loop Flow Analysis.** Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Actual power flows are the metered flows at an interface for a defined period. Scheduled power flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for a balancing authority (net actual interchange) and the total scheduled flows for the balancing authority (net scheduled interchange) for a defined period. Loop flows are defined as the difference between actual and scheduled power 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 system actual and scheduled flow could net to a zero difference. As an illustration, although PJM's total scheduled and actual flows differed by only 2.2 percent in 2009, much greater differences existed at individual interfaces.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority 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 can also result from actions within balancing authorities.

Loop flows 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 as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow would provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market areas and among market and non market areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (non market areas), 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 flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. NERC Tag data, dynamic schedule and pseudo-tie data and actual tie line data are required in order to analyze the differences between actual and scheduled transactions. The area control error (ACE) data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions. All data should be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

- **Dynamic Interface Pricing.** According to the *PJM Interface Price Definition Methodology*, dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[21] The weighting factors are determined in such a manner that the interface reflects actual system conditions. The topology of the transmission system is constantly changing, as generation comes on and

21 See "*PJM Interface Pricing Definition Methodology.*" (September 29, 2006) (Accessed January 20, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx> (33 KB).

off line, and transmission lines come in and out of service. The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified only occasionally. The MMU recommends that PJM monitor, and adjust as necessary, the buses and weightings applied to the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.

- **PJM Transmission Loading Relief Procedures (TLRs).** During 2009, PJM issued 129 TLRs. Of the 129 TLRs issued, the highest levels reached were TLR 3a in 61 instances and TLR 3b in the remaining 68 events. This represents a decrease of 14 percent in TLRs from the 150 TLRs issued during 2008 (55 TLR 3a, 92 TLR 3b, 2 TLR 4 and 1 TLR 5b).

- **Up-To Congestion.** The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Market. This product was offered as a tool for market participants to limit their congestion exposure on physical transactions in the Real-Time Market.

  Submitting an up-to congestion bid is similar to entering a matched pair of incremental offers (INC) and decrement bids (DEC). However, there are a number of advantages to using the up-to congestion product relative to using sets of INC and DEC bids. For example: an up-to congestion transaction is approved or denied as a single transaction; an up-to congestion bid will only clear the Day-Ahead Market if the maximum congestion bid criterion is met; and an up-to congestion transaction is not subject to day-ahead or balancing operating reserve charges.

  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.[22] 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 increase the cleared volume of up-to congestion transactions, and aggravate the issue.

  On February 21, 2008, the PJM Markets and Reliability Committee (MRC) approved PJM's proposed resolution to the request for implementation on March 1, 2008.[23] The proposal allowed for a modification to the offer cap from $25 to ± $50, including an explicit allowance for negative offers. PJM also eliminated a relatively small number of available sources and sinks in an effort to partially address the mismatch between the Day-Ahead and Real-Time Market scheduling. In the period following the March 1, 2008 modifications to the up-to congestion bids, through December 31, 2009, the monthly average of up-to congestion bidding increased from 3,027.1 GWh to 4,556.8 GWh.

22 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221/20080221-item-03-up-to-congestion-transactions.ashx> (39KB).

23 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221/20080221-minutes.ashx> (61KB).

The up-to congestion transactions in 2009 were comprised of 45.6 percent imports, 51.7 percent exports and 2.7 percent wheeling transactions. Only 0.2 percent of the up-to congestion transactions had matching Real-Time Market transactions. Of the up-to congestion transactions with matching Real-Time Market transactions, 26.5 percent were imports, 58.5 percent were exports and 15.0 percent were wheel through transactions.

When the up-to congestion product was used as intended, with matching Real-Time Market transactions, 57.0 percent of the total cleared transaction MW were profitable in 2009. The net profit on all these transactions was approximately $100,000. When up-to congestion transactions did not have a matching Real-Time Market transaction, 61.7 percent of the total cleared transaction MW were profitable. The net loss on all these transactions was approximately $31.5 million.

The MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges.

The MMU also recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding and for all import and export transactions in the Day-Ahead and the Real-Time Markets. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

- **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 available for interface pricing between PJM and neighboring balancing authorities (BA).[24] These options are: the existing SouthIMP/SouthEXP prices; the "Hi/Low" method; and the "Marginal Cost Proxy Method."

24 The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model" (August 2008) (Accessed January 20, 2010) <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf> (381 KB).

The proposed tariff revisions were filed with FERC on December 2, 2008, and approved on May 1, 2009. [25] 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 marginal cost proxy pricing method beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[26] As of December 31, 2009, Duke Energy Carolinas and Progress Energy Carolinas were in the process of negotiating a congestion management agreement with PJM.

In September 2009, Progress Energy Carolinas provided an update to the PJM Market Implementation Committee (MIC) on the proposed congestion management agreement.[27] As presented, the proposal includes three parts: enhanced available transmission capability (ATC) coordination; monitoring of real-time parallel flow impacts; and managing real-time congestion.

The MMU supports congestion management agreements but recommends that such agreements be implemented on a regional basis rather than between RTOs and individual external utility companies. In addition, there are a number of issues in the PJM/PEC agreement that need to be addressed. Most fundamentally, any congestion management agreement must ensure that the interface price established reflects the economic fundamentals of an LMP market.

- **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 JOA with the 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.[28] 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, willing to pay congestion (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 within two hours from the queue time when queued the day prior. On June 23, 2009, PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage has been over 99 percent, compared to 70 percent prior to the modification. The MMU will continue to monitor participant use of spot import service.

25 PJM Interconnection, L.L.C., Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008). PJM Interconnection, L.L.C., Letter Order, Docket No. ER09-369-000 (May 1, 2009).
26 127 FERC ¶61,101.
27 See "PJM-Progress Draft Congestion Management Agreement"(September 10, 2009) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mic/20090910/20090910-item-08-pjm-progress-draft-congestion-management-agreement.ashx> (69 KB).
28 See "WPC White Paper" (April 20, 2007) (Accessed January 15, 2010) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** When reserving non-firm transmission, the market participant has the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow.

  If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction.

  Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. The method that PJM uses to curtail not willing to pay congestion requires the transaction to be loaded. While loaded, if congestion occurs for a not willing to pay congestion transaction, a message is sent to the PJM operators requesting the transaction be curtailed at the next 15 minute interval.

  The total uncollected congestion charges for 2009 were $688,547 which was a reduction of 92 percent from the 2008 total of $8,662,695. The MMU recommends modifying the evaluation criteria via a change to PJM's market software, to ensure that a not willing to pay congestion transactions is not permitted to flow in the presence of congestion.

- **Ramp Availability.** The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit was set based on the generally available ramping capability of generators on the PJM system. PJM must limit the amount of imports or exports at each 15 minute interval to account for the physical characteristics of the generation to meet the imports and exports. In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intra-hour LMP changes. As a result, a new business rule was proposed, and approved, to require all transactions to be at least 45 minutes in duration.[29] On May 1, 2008, the Enhanced Energy Scheduling (EES) system was modified to require that transactions be 45 minutes in duration. Since that modification, market participants have scheduled 1 MW for the first 30 minutes, and increased to a larger MW value for the last 15 minutes, thus continuing to create significant swings in imports and exports. The MMU recommends that the EES application be modified further to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible.

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 not transparent.

29 PJM "Manual 41: Managing Interchange," Revision 03 (November 24, 2008), p. 5.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities for 2009, including evolving transaction patterns, economics and issues. During 2009, PJM was 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 62 percent of the total real-time net exports and two interfaces accounted for 88 percent of the real-time net import volume. Three interfaces accounted for 58 percent of the total day-ahead net exports and three interfaces accounted for 85 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 ensure that market signals are used to manage constraints affecting interarea transactions. PJM and the NYISO, as neighboring market areas, should develop market based congestion management protocols as soon as practicable. The NYISO and the neighboring balancing authorities have taken initial steps to do so. 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 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, accurately reflects actual LMP impacts on PJM, and that all participants have access to the defined pricing when in the same position. The goal of such pricing agreements should be to replicate LMP price signals that reflect the actual loads and the actual dispatch of units for all parties to such agreements.

Loop flows are defined as the difference between actual and scheduled (contract path) power 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. 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 can 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 Day-Ahead 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. The MMU recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding and for all import and export transactions in the Day-Ahead and the Real-Time Markets. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM was a monthly net importer of energy in the Real-Time Market in January, February, March and May of 2009, and a net exporter of energy in the remaining months. (See Figure 4-1, Figure 4-2 and Figure 4-3.)[30] Total net interchange of -1,407 GWh was less than net interchange of -12,124 GWh in 2008. The peak month for net exporting interchange was June in 2009, -1,031 GWh; it had also been June in 2008, -2,388 GWh. The peak month for net importing interchange was January in 2009, 1,715 GWh; it had been December in 2008, 695 GWh. Monthly gross exports averaged 3,788 GWh and monthly gross imports averaged 3,671 GWh, for an average monthly net interchange of -117 GWh.

PJM was a net importer of energy in the Day-Ahead Market in July (182 GWh), and a net exporter of energy in the remaining months. Total net interchange was -9,033 GWh. The peak month for net exporting interchange was October, -2,204 GWh. Monthly gross exports averaged 4,826 GWh and monthly gross imports averaged 4,073 GWh, for an average monthly net interchange of -753 GWh.

While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. Transactions in the Day-Ahead Market create financial obligations to deliver in the Real-Time Market and to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Energy Markets. In 2009, gross imports in the Day-Ahead Energy Market were 111 percent of the Real-Time Market's gross imports (90 percent in 2008), gross exports in the Day-Ahead Market were 127 percent of the Real-Time Market's gross exports (106 percent in 2008) and net interchange in the Day-Ahead Energy Market exceeded the net interchange in the Real-Time Energy Market by 642 percent (-1,407 GWh in the Real-Time Market and -9,033 GWh in the Day-Ahead Market).

30 Calculated values shown in Section 4, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Figure 4-1 PJM real-time scheduled imports and exports: Calendar year 2009

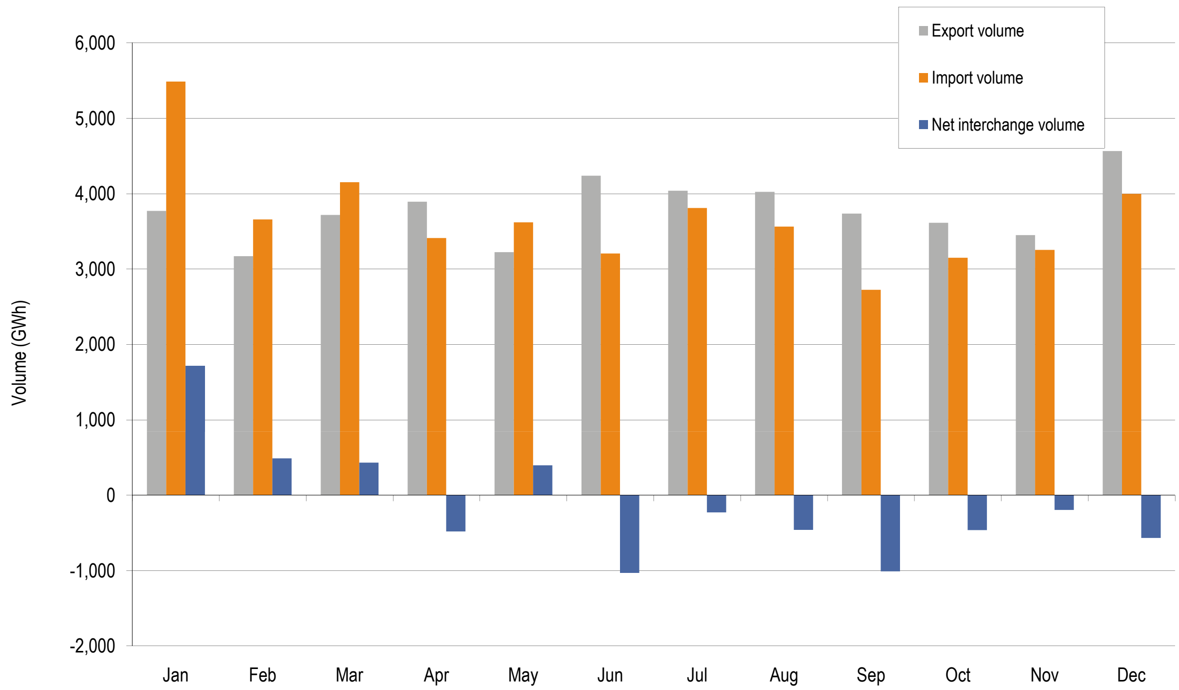


Figure 4-2 PJM day-ahead scheduled imports and exports: Calendar year 2009

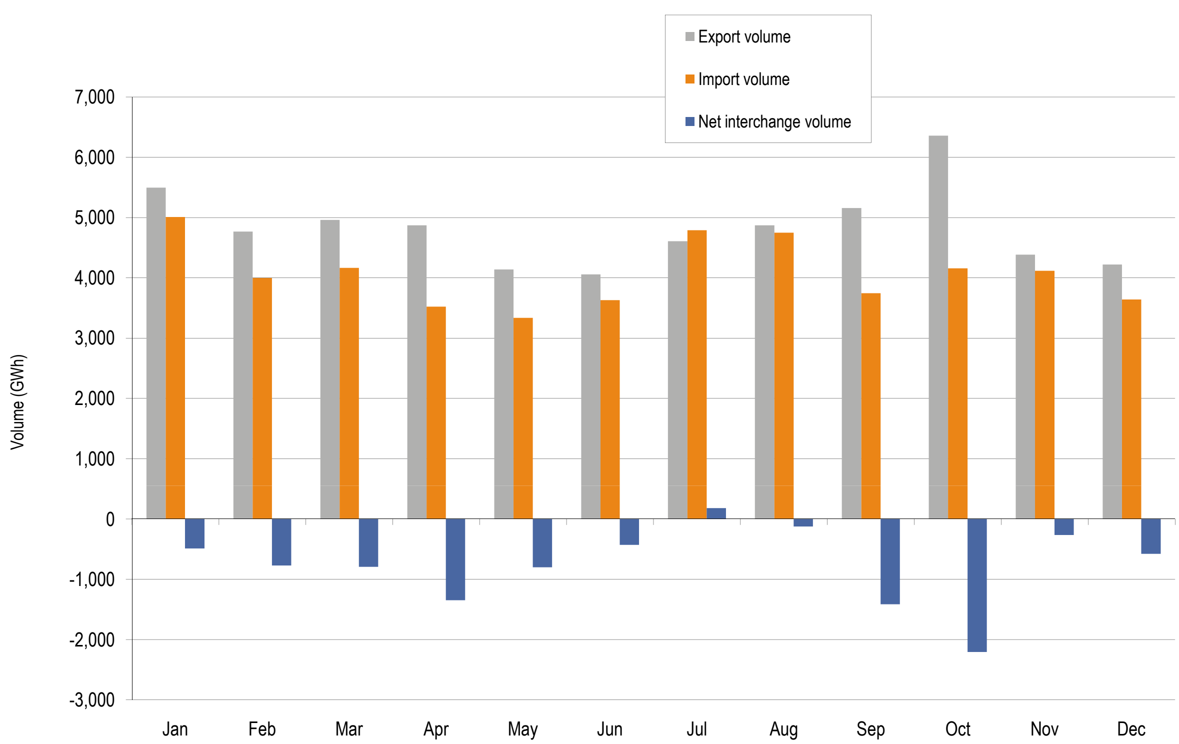
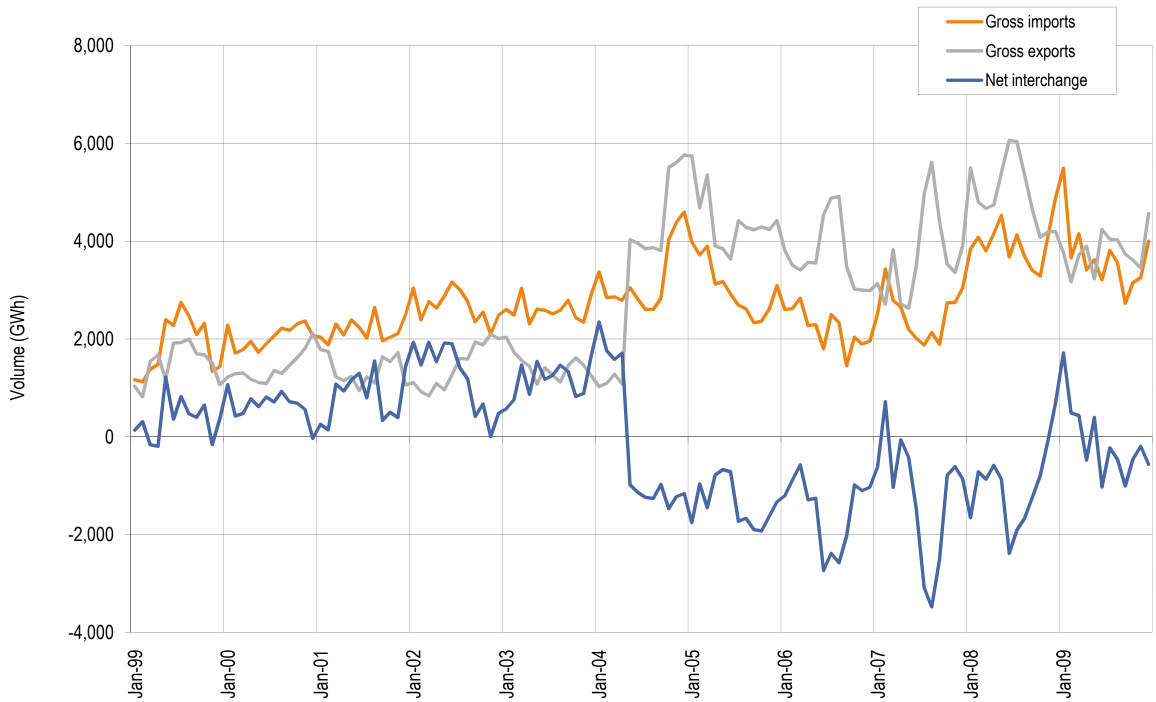


Figure 4-3 shows real-time import and export volume for PJM from 1999 through 2009. PJM became a consistent net exporter of energy in 2004, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time.

Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through December 2009



Interface Imports and Exports

In November of 2009, the Linden variable frequency transformer (VFT) facility was placed in service. As a result, a new interface was created, bringing the total number of interfaces between PJM and other balancing authorities to 21. The Linden (LIND) interface and the Neptune (NEPT) Interface are separate from the NYIS Interface. However, all three are between PJM and the NYISO. Table 4-1 through Table 4-6 show the interchange totals at the individual interfaces with the NYISO, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and the Midwest ISO are shown, as well as with the Midwest ISO as a whole.

Total imports and exports are comprised of flows at each PJM interface. Net interchange in the Real-Time Market is shown by interface for 2009 in Table 4-1 while gross imports and exports are shown in Table 4-2 and Table 4-3. Net interchange in the Day-Ahead Market is shown by interface for 2009 in Table 4-4 while gross imports and exports are shown in Table 4-5 and Table 4-6.

In 2009, there were net exports in the Real-Time Market at 12 of PJM's 21 interfaces. (See Table 4-7 for active interfaces during 2009.) The top three exporting interfaces accounted for 62 percent of PJM's total net exports: PJM/NYIS with 28 percent, PJM/NEPT with 25 percent and PJM/CPLE with 9 percent of the net export volume. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND). Combined, these interfaces made up 55 percent of the total net PJM exports in the Real-Time Market.

Economic fundamentals were the key driver for the net exports through the NYIS Interface in the Real-Time Market. Figure 4-13 shows that PJM's PJM/NYIS average hourly interface price was $1.79 less than the NYISO's NYIS/PJM Interface price, and net exports are consistent with purchasing at a lower price and selling at a higher price. The PJM/NEPT flow averaged approximately -550 MW for each hour through 2009. As with the PJM/NYIS interface, the PJM/NEPT Interface price was, on average lower than the NYIS/NEPT bus price ($41.94 in PJM vs. $49.24 in the NYISO). Similarly, the PJM/LIND Interface price averaged $38.19, while the NYISO/Linden bus price averaged $43.22.

The PJM/CPLE exports are based on economic fundamentals. Figure 4-26 and Figure 4-27 show the correlation between the price available to CPLE imports and exports and their corresponding interchange. As the average hourly price available to CPLE decreases, exports to CPLE increase.

In 2009, there were net exports in the Day-Ahead Market at 14 of PJM's 21 interfaces. The top three exporting interfaces accounted for 58 percent of PJM's total net exports, PJM/ALTW with 24 percent, PJM/ALTE with 17 percent and PJM/NEPT with 17 percent.

There were net imports in the Real-Time Market at nine of PJM's interfaces. Two net importing interfaces accounted for 88 percent of PJM's net import volume, PJM/OVEC with 68 percent and PJM/MECS with 20 percent of the net import volume.

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of the shares of ownership belong to load serving entities, or their affiliates, within the PJM footprint. The agreement requires delivery of approximately 70 percent of the generation output into the PJM footprint.[31] OVEC itself does not serve load, and therefore does not import energy. The nature of the ownership of OVEC and the location of its affiliates within the PJM footprint account for the large percentage of PJM's net interchange volume.

The primary reason for the imports at the PJM/MECS Interface is that excess generation from the IESO is often scheduled through the Midwest ISO and into PJM through the PJM/MECS Interface. This is the path with the lowest cost of transmission between the IESO and PJM. While there is an alternate transmission path through the NYISO, transmission charges are higher on this path. This is a result of the fact that the transmission through the Midwest ISO, for transactions sinking in PJM, would be a free service due to the regional through and out rate. The fact that there is an additional transmission charge through the NYISO makes this a more costly transmission path for transactions from the IESO into PJM.

There were net imports in the Day-Ahead Market at seven of PJM's 21 interfaces. The top three net importing interfaces accounted for 85 percent of PJM's total net imports, PJM/OVEC with 53 percent, PJM/WEC with 18 percent and PJM/MECS with 15 percent.

31 See "Ohio Valley Electric Corporation: Company Background." (Accessed January 24, 2010) <http://www.ovec.com/OVECHistory.pdf> (26 KB).

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(62.7)	(161.8)	(208.1)	(281.1)	(113.8)	(293.2)	(317.7)	(242.9)	(241.7)	35.9	3.1	53.2	(1,830.8)
CPLW	(71.4)	(67.4)	(74.3)	(72.0)	(60.3)	(69.8)	(74.6)	(76.7)	(57.6)	0.0	(3.5)	(56.1)	(683.7)
DUK	622.7	67.8	89.9	10.6	60.9	(86.0)	(135.9)	(67.5)	(180.9)	(70.2)	(39.2)	126.6	398.8
EKPC	(173.5)	(78.8)	(88.6)	(57.4)	67.3	(9.7)	(45.0)	(57.3)	(113.1)	(40.8)	(35.6)	(41.8)	(674.3)
LGEE	137.4	90.7	176.3	101.4	169.8	32.6	(3.9)	54.6	43.5	69.4	80.9	62.6	1,015.3
MEC	150.4	302.1	146.1	155.1	(148.4)	(239.8)	(117.9)	(26.8)	(446.6)	(483.0)	(451.8)	(446.7)	(1,607.3)
MISO	388.0	(153.5)	(96.0)	(804.4)	81.0	(277.4)	405.6	(78.5)	9.5	1.9	383.7	349.0	208.9
ALTE	44.4	(41.8)	(86.5)	(147.3)	(117.6)	(143.6)	(136.3)	(94.9)	(39.1)	(27.7)	(9.0)	39.4	(760.0)
ALTW	(65.6)	(69.6)	(74.3)	(97.5)	(66.4)	(175.3)	(230.4)	(151.1)	(92.2)	(70.8)	(29.5)	(4.2)	(1,126.9)
AMIL	126.2	23.7	8.7	(14.9)	28.0	(24.0)	(6.8)	(13.6)	24.6	39.8	17.7	(43.6)	165.8
CIN	102.6	(96.1)	(179.7)	(216.6)	14.7	(91.8)	154.0	133.9	206.5	70.9	109.9	187.2	395.5
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
FE	(215.6)	(221.5)	(166.6)	(204.3)	(178.6)	(93.1)	(16.8)	(80.2)	(168.8)	(45.9)	(63.6)	(78.1)	(1,533.1)
IPL	47.1	(17.5)	(88.6)	(79.8)	101.5	(23.9)	173.4	(5.7)	(14.2)	(18.0)	25.3	67.8	167.4
MECS	421.7	361.8	552.3	60.9	341.6	398.7	512.8	258.3	157.3	113.9	276.8	163.6	3,619.7
NIPS	(8.2)	(51.5)	(35.5)	(60.0)	(3.9)	(38.1)	(13.9)	(71.5)	(28.0)	(11.4)	(0.6)	(19.3)	(341.9)
WEC	(64.6)	(41.0)	(26.5)	(44.9)	(38.3)	(86.3)	(30.4)	(53.7)	(36.6)	(48.9)	56.7	36.2	(378.3)
NYISO	(690.9)	(634.2)	(698.4)	(581.7)	(700.0)	(922.9)	(983.5)	(1,068.2)	(844.6)	(970.7)	(1,143.3)	(1,682.4)	(10,920.8)
LIND									(8.9)	(44.5)	(151.8)	(148.8)	(354.0)
NEPT	(294.8)	(402.5)	(445.1)	(400.9)	(434.5)	(456.9)	(493.9)	(484.6)	(382.6)	(265.4)	(426.0)	(473.5)	(4,960.7)
NYIS	(396.1)	(231.7)	(253.3)	(180.8)	(265.5)	(466.0)	(489.6)	(583.6)	(453.1)	(660.8)	(565.5)	(1,060.1)	(5,606.1)
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	1,116.3	1,125.0	865.0	1,015.1	1,041.3	1,198.6	12,523.3
TVA	244.0	128.7	167.6	35.2	69.3	(160.0)	(73.1)	(23.1)	(42.7)	(21.0)	(30.1)	(131.2)	163.6
Total	1,715.3	487.8	432.9	(481.8)	396.2	(1,031.0)	(229.7)	(461.4)	(1,009.2)	(463.4)	(194.5)	(568.2)	(1,407.0)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	223.9	69.4	66.8	39.9	115.1	16.8	9.3	17.0	5.2	139.8	115.7	325.2	1,144.1
CPLW	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1
DUK	737.8	277.9	209.5	154.1	239.2	151.2	101.4	98.5	72.6	155.4	90.9	308.5	2,597.0
EKPC	2.7	6.1	12.9	2.5	90.3	33.2	11.6	4.2	0.9	11.8	9.4	11.8	197.4
LGEE	187.4	125.2	183.6	125.8	172.0	55.7	48.0	72.1	44.3	70.4	84.5	89.5	1,258.5
MEC	337.6	428.2	371.7	361.2	77.8	26.5	113.5	182.9	4.8	15.5	26.4	51.7	1,997.8
MISO	1,529.0	983.6	1,245.6	627.0	1,015.4	1,105.8	1,482.9	1,058.8	909.6	864.9	1,050.8	1,110.4	12,983.8
ALTE	170.4	65.4	18.2	1.7	0.1	0.1	1.7	0.0	2.1	0.0	0.0	44.4	304.1
ALTW	45.7	22.2	1.7	0.0	1.9	3.5	5.1	0.3	4.8	0.0	24.9	14.3	124.4
AMIL	147.3	44.9	38.3	26.8	62.2	48.6	65.8	54.0	46.5	76.9	51.3	66.3	728.9
CIN	382.9	265.0	335.2	209.3	256.2	335.3	332.8	402.7	443.7	315.4	279.0	388.5	3,946.0
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
FE	60.5	32.6	101.6	60.8	73.0	160.0	251.7	180.8	130.3	207.3	185.4	177.1	1,621.1
IPL	107.5	43.8	51.9	63.5	148.6	65.7	199.1	52.0	33.0	34.4	53.7	79.2	932.4
MECS	573.5	500.4	679.7	264.3	458.0	486.8	601.6	368.9	246.7	220.0	355.6	248.8	5,004.3
NIPS	32.5	8.1	0.5	0.0	11.0	0.0	18.2	0.0	0.0	1.3	1.4	0.0	73.0
WEC	8.7	1.2	17.8	0.6	4.4	5.8	6.9	0.1	2.5	9.6	99.5	91.8	248.9
NYISO	1,004.4	589.8	829.7	982.3	795.2	791.0	862.5	915.8	738.0	810.7	763.7	819.8	9,902.9
LIND									0.0	0.5	0.2	0.0	0.7
NEPT	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
NYIS	1,004.4	589.8	829.7	982.3	795.2	791.0	862.5	915.8	738.0	810.2	763.5	819.8	9,902.2
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	1,116.3	1,125.0	865.0	1,015.1	1,041.3	1,198.6	12,523.3
TVA	292.8	185.1	214.2	107.1	146.2	31.4	65.9	88.9	86.0	66.6	72.5	83.0	1,439.7
Total	5,489.0	3,659.5	4,152.4	3,412.4	3,621.6	3,206.8	3,811.4	3,563.2	2,726.4	3,150.2	3,255.2	3,998.5	44,046.6

Table 4-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	286.6	231.2	274.9	321.0	228.9	310.0	327.0	259.9	246.9	103.9	112.6	272.0	2,974.9
CPLW	73.5	67.4	74.3	72.0	60.3	69.8	74.6	76.7	57.6	0.0	3.5	56.1	685.8
DUK	115.1	210.1	119.6	143.5	178.3	237.2	237.3	166.0	253.5	225.6	130.1	181.9	2,198.2
EKPC	176.2	84.9	101.5	59.9	23.0	42.9	56.6	61.5	114.0	52.6	45.0	53.6	871.7
LGEE	50.0	34.5	7.3	24.4	2.2	23.1	51.9	17.5	0.8	1.0	3.6	26.9	243.2
MEC	187.2	126.1	225.6	206.1	226.2	266.3	231.4	209.7	451.4	498.5	478.2	498.4	3,605.1
MISO	1,141.0	1,137.1	1,341.6	1,431.4	934.4	1,383.2	1,077.3	1,137.3	900.1	863.0	667.1	761.4	12,774.9
ALTE	126.0	107.2	104.7	149.0	117.7	143.7	138.0	94.9	41.2	27.7	9.0	5.0	1,064.1
ALTW	111.3	91.8	76.0	97.5	68.3	178.8	235.5	151.4	97.0	70.8	54.4	18.5	1,251.3
AMIL	21.1	21.2	29.6	41.7	34.2	72.6	72.6	67.6	21.9	37.1	33.6	109.9	563.1
CIN	280.3	361.1	514.9	425.9	241.5	427.1	178.8	268.8	237.2	244.5	169.1	201.3	3,550.5
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
FE	276.1	254.1	268.2	265.1	251.6	253.1	268.5	261.0	299.1	253.2	249.0	255.2	3,154.2
IPL	60.4	61.3	140.5	143.3	47.1	89.6	25.7	57.7	47.2	52.4	28.4	11.4	765.0
MECS	151.8	138.6	127.4	203.4	116.4	88.1	88.8	110.6	89.4	106.1	78.8	85.2	1,384.6
NIPS	40.7	59.6	36.0	60.0	14.9	38.1	32.1	71.5	28.0	12.7	2.0	19.3	414.9
WEC	73.3	42.2	44.3	45.5	42.7	92.1	37.3	53.8	39.1	58.5	42.8	55.6	627.2
NYISO	1,695.3	1,224.0	1,528.1	1,564.0	1,495.2	1,713.9	1,846.0	1,984.0	1,582.6	1,781.4	1,907.0	2,502.2	20,823.7
LIND									8.9	45.0	152.0	148.8	354.7
NEPT	294.8	402.5	445.1	400.9	434.5	456.9	493.9	484.6	382.6	265.4	426.0	473.5	4,960.7
NYIS	1,400.5	821.5	1,083.0	1,163.1	1,060.7	1,257.0	1,352.1	1,499.4	1,191.1	1,471.0	1,329.0	1,879.9	15,508.3
OVEC	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
TVA	48.8	56.4	46.6	71.9	76.9	191.4	139.0	112.0	128.7	87.6	102.6	214.2	1,276.1
Total	3,773.7	3,171.7	3,719.5	3,894.2	3,225.4	4,237.8	4,041.1	4,024.6	3,735.6	3,613.6	3,449.7	4,566.7	45,453.6

Table 4-4 Day-ahead net interchange volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	49.1	(23.0)	(86.0)	(81.0)	(88.1)	(157.1)	(158.8)	(109.9)	(91.0)	(43.0)	(103.0)	(109.6)	(1,001.4)
CPLW	(176.6)	(166.0)	(184.5)	(180.0)	(155.9)	(176.2)	(184.7)	(184.0)	(147.8)	7.7	(5.0)	(165.5)	(1,718.5)
DUK	255.9	26.4	1.1	22.3	120.9	58.7	88.5	45.5	(30.9)	85.8	(6.0)	70.3	738.6
EKPC	(31.1)	(22.8)	(1.1)	0.0	0.0	0.0	0.0	(1.4)	(0.3)	(1.2)	(0.1)	(1.4)	(59.4)
LGEE	(16.5)	(8.9)	23.5	6.9	9.7	39.9	38.0	2.7	46.4	(0.4)	(0.5)	4.2	145.0
MEC	27.3	(90.0)	(173.4)	(185.3)	(209.3)	(252.9)	(216.0)	(207.8)	(448.7)	(497.0)	(482.6)	(491.7)	(3,227.4)
MISO	(1,745.7)	(1,357.3)	(995.7)	(1,356.4)	(870.3)	(275.1)	57.2	(252.5)	(948.0)	(2,141.7)	26.3	130.9	(9,728.3)
ALTE	(142.2)	(61.4)	(518.5)	(673.0)	(779.1)	(521.6)	(340.1)	(409.7)	(542.5)	(573.2)	(321.9)	(26.8)	(4,910.0)
ALTW	(722.6)	(756.0)	(604.5)	(746.7)	(389.5)	(497.7)	(392.8)	(552.0)	(417.7)	(1,261.5)	(320.2)	(246.4)	(6,907.6)
AMIL	52.8	72.3	42.2	86.6	102.4	261.6	153.3	32.6	6.3	33.8	7.7	47.9	899.5
CIN	(225.4)	(96.3)	(47.8)	57.5	(36.7)	55.7	(8.5)	85.2	80.3	23.1	20.5	(97.6)	(190.0)
CWLP	(0.7)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.8)
FE	(206.7)	(233.8)	(241.4)	(197.3)	(206.0)	(116.4)	(119.4)	(76.8)	(115.4)	(152.1)	53.3	(21.5)	(1,633.5)
IPL	(316.7)	(191.0)	(157.2)	(67.1)	85.2	143.0	254.3	165.3	(34.8)	(35.4)	(1.3)	(46.3)	(202.0)
MECS	101.9	172.9	250.4	261.1	370.6	433.8	548.7	356.0	257.0	9.2	111.6	77.8	2,951.0
NIPS	(233.7)	(320.9)	(71.3)	(194.6)	(286.2)	(62.2)	(81.7)	(287.8)	(591.0)	(828.0)	(341.6)	(77.6)	(3,376.6)
WEC	(52.5)	57.0	352.4	117.2	269.0	28.7	43.4	434.7	409.8	642.4	818.2	521.4	3,641.7
NYISO	(167.7)	(257.3)	(315.6)	(394.7)	(438.4)	(480.5)	(489.0)	(533.8)	(564.7)	(534.1)	(710.3)	(920.5)	(5,806.6)
LIND									(2.7)	(44.0)	(82.8)	(55.1)	(184.6)
NEPT	(326.4)	(403.8)	(446.4)	(402.1)	(436.6)	(472.3)	(496.9)	(491.7)	(408.7)	(262.6)	(440.2)	(476.6)	(5,064.3)
NYIS	158.7	146.5	130.8	7.5	(1.8)	(8.2)	7.9	(42.1)	(153.3)	(227.5)	(187.3)	(388.8)	(557.7)
OVEC	835.6	743.5	786.0	738.6	824.2	857.3	1,028.8	1,038.7	795.4	914.6	1,004.2	938.3	10,505.2
TVA	482.5	384.6	151.7	81.8	5.4	(42.8)	18.0	79.6	(22.7)	5.4	10.6	(33.9)	1,120.2
Total	(487.2)	(770.8)	(794.0)	(1,347.6)	(801.8)	(428.7)	182.0	(122.9)	(1,412.3)	(2,203.9)	(266.4)	(578.9)	(9,032.5)

Table 4-5 Day-ahead gross import volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	187.6	75.8	14.4	21.0	24.0	7.8	7.4	19.8	12.4	40.7	12.4	44.4	467.7
CPLW	9.5	2.1	0.6	0.0	2.8	0.0	2.2	2.0	0.0	9.7	1.4	1.5	31.8
DUK	291.9	102.7	55.9	71.4	138.8	90.0	123.6	66.8	83.6	116.1	28.9	103.9	1,273.6
EKPC	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	1.1
LGEE	2.9	0.2	24.9	8.1	11.4	41.0	40.1	5.2	46.4	0.1	0.1	4.2	184.6
MEC	173.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	1.5	0.0	6.8	183.2
MISO	2,090.9	2,059.3	2,312.2	1,779.9	1,700.4	1,947.7	2,704.6	2,558.3	2,005.4	2,239.6	2,257.1	1,739.4	25,394.8
ALTE	675.2	674.4	470.1	173.7	52.2	106.5	367.9	191.1	171.6	314.2	285.0	396.0	3,877.9
ALTW	190.8	183.6	33.2	2.3	0.0	12.5	29.9	40.4	15.8	47.7	59.5	20.4	636.1
AMIL	59.4	75.0	44.5	91.5	105.0	261.6	155.7	76.1	17.7	33.8	8.4	48.3	977.0
CIN	103.2	159.2	178.5	247.6	190.5	320.2	273.2	328.9	391.8	316.2	193.2	134.5	2,837.0
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
FE	15.2	44.9	60.0	23.0	10.3	100.7	206.1	227.7	242.0	140.3	341.6	177.1	1,588.9
IPL	246.5	159.9	153.2	254.2	258.7	250.0	389.3	374.6	77.6	126.5	32.6	1.2	2,324.3
MECS	504.9	400.1	488.5	606.8	631.9	626.5	769.8	595.9	390.9	336.1	359.3	285.6	5,996.3
NIPS	284.5	248.4	490.5	208.0	135.6	151.4	338.2	231.6	152.0	72.6	74.6	29.2	2,416.6
WEC	11.2	113.8	393.7	172.7	316.2	118.3	174.5	492.0	546.0	852.2	902.9	647.1	4,740.6
NYISO	890.3	584.5	776.0	776.4	612.0	675.0	840.6	958.6	710.3	748.1	733.2	731.1	9,036.1
LIND									0.0	0.1	0.0	0.0	0.1
NEPT	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
NYIS	890.3	584.5	776.0	776.4	612.0	675.0	840.6	958.6	710.3	748.0	733.2	731.1	9,036.0
OVEC	866.7	766.6	810.5	763.1	828.4	858.2	1,032.0	1,043.8	840.5	954.7	1,036.2	981.4	10,782.1
TVA	496.4	407.2	172.8	104.0	20.2	12.0	40.4	96.3	46.0	46.9	50.7	30.7	1,523.6
Total	5,010.2	3,998.4	4,167.3	3,524.0	3,338.0	3,631.7	4,790.9	4,750.8	3,746.3	4,157.7	4,120.0	3,643.4	48,878.7

Table 4-6 Day-ahead gross export volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	138.5	98.8	100.4	102.0	112.1	164.9	166.2	129.7	103.4	83.7	115.4	154.0	1,469.1
CPLW	186.1	168.1	185.1	180.0	158.7	176.2	186.9	186.0	147.8	2.0	6.4	167.0	1,750.3
DUK	36.0	76.3	54.8	49.1	17.9	31.3	35.1	21.3	114.5	30.3	34.9	33.6	535.0
EKPC	31.9	22.8	1.1	0.0	0.0	0.0	0.0	1.4	0.3	1.5	0.1	1.4	60.5
LGEE	19.4	9.1	1.4	1.2	1.7	1.1	2.1	2.5	0.0	0.5	0.6	0.0	39.6
MEC	145.9	90.0	173.4	185.3	209.3	252.9	216.0	207.8	450.4	498.5	482.6	498.5	3,410.6
MISO	3,836.6	3,416.6	3,307.9	3,136.3	2,570.7	2,222.8	2,647.4	2,810.8	2,953.4	4,381.3	2,230.8	1,608.5	35,123.1
ALTE	817.4	735.8	988.6	846.7	831.3	628.1	708.0	600.8	714.1	887.4	606.9	422.8	8,787.9
ALTW	913.4	939.6	637.7	749.0	389.5	510.2	422.7	592.4	433.5	1,309.2	379.7	266.8	7,543.7
AMIL	6.6	2.7	2.3	4.9	2.6	0.0	2.4	43.5	11.4	0.0	0.7	0.4	77.5
CIN	328.6	255.5	226.3	190.1	227.2	264.5	281.7	243.7	311.5	293.1	172.7	232.1	3,027.0
CWLP	0.7	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
FE	221.9	278.7	301.4	220.3	216.3	217.1	325.5	304.5	357.4	292.4	288.3	198.6	3,222.5
IPL	563.2	350.9	310.4	321.3	173.5	107.0	135.0	209.3	112.4	161.9	33.9	47.5	2,526.3
MECS	403.0	227.2	238.1	345.8	261.3	192.7	221.1	239.9	133.9	326.9	247.7	207.8	3,045.3
NIPS	518.2	569.3	561.8	402.6	421.8	213.6	419.9	519.4	743.0	900.6	416.2	106.8	5,793.2
WEC	63.7	56.8	41.3	55.5	47.2	89.6	131.1	57.3	136.2	209.8	84.7	125.7	1,098.9
NYISO	1,058.0	841.8	1,091.6	1,171.1	1,050.4	1,155.5	1,329.6	1,492.4	1,275.0	1,282.2	1,443.5	1,651.6	14,842.7
LIND									2.7	44.1	82.8	55.1	184.7
NEPT	326.4	403.8	446.4	402.1	436.6	472.3	496.9	491.7	408.7	262.6	440.2	476.6	5,064.3
NYIS	731.6	438.0	645.2	768.9	613.8	683.2	832.7	1,000.7	863.6	975.5	920.5	1,119.9	9,593.7
OVEC	31.1	23.1	24.5	24.5	4.2	0.9	3.2	5.1	45.1	40.1	32.0	43.1	276.9
TVA	13.9	22.6	21.1	22.2	14.8	54.8	22.4	16.7	68.7	41.5	40.1	64.6	403.4
Total	5,497.4	4,769.2	4,961.3	4,871.6	4,139.8	4,060.4	4,608.9	4,873.7	5,158.6	6,361.6	4,386.4	4,222.3	57,911.2

Transactions Basics

Interchange Transactions – Real-Time Energy Market

There are three steps required for market participants to enter external interchange transactions in PJM's Real-Time Energy Market. The steps are: acquisition of valid transmission via the Open Access Same Time Information System (OASIS); acquisition of available ramp via PJM's Enhanced Energy Scheduler system (EES); and the creation of a valid NERC Tag. In addition, the interchange request must pass the neighboring balancing authority checkout process in order for the request to be implemented. After a successful implementation of an external energy schedule, the energy will flow between balancing authorities. Such a transaction will continue to flow at its designated energy profile as long as the system can support it, it is deemed economic based on options set at the time of scheduling, or until the market participant chooses to curtail the transaction.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction.

Interchange Transactions – Day-Ahead Energy Market

Entering external energy transactions in the Day-Ahead Market requires fewer steps than the Real-Time Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Market. Day-Ahead Market schedules need to be cleared through the Day-Ahead Market process in order to become an approved schedule. The Day-Ahead Market transactions are financially binding but will not physically flow. In the Day-Ahead Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: Fixed; Up-to congestion; and Dispatchable.

A fixed Day-Ahead Market transaction request means that the market participant agrees to be a price taker for the MW amount of the offer. There is no price associated with the request and the market participant agrees to take the day-ahead LMP at the associated source or sink. If the market participant has met the required deadline and has acquired a valid willing-to-pay congestion OASIS reservation, a fixed day-ahead transaction request will be accepted in the Day-Ahead Market. These approved transactions are a financial obligation. If the market participant does not provide a corresponding transaction in the Real-Time Market, they are subject to the balancing market settlement.

To submit an up-to congestion offer, the market participant is required to submit an energy profile (start time, stop time and MW value) and specify the amount of congestion they are willing to pay. If, in the Day-Ahead Market, congestion on the desired path is less than that specified, the up-to congestion request is approved. Approved up-to congestion offers are financial obligations.

Dispatchable transactions in the Day-Ahead Market are similar to those in the Real-Time Market in that they are evaluated against a floor or ceiling price at the designated import or export pricing point. For import dispatchable transactions, if the LMP at the interface clears higher than the specified bid, the transaction is approved. For export dispatchable transactions, if the LMP at the interface clears lower than the specified bid, the transaction is approved. As with fixed and up-to congestion transactions, cleared dispatchable transactions in the Day-Ahead Market represent a financial obligation. If the market participant does not meet the commitment in the Real-Time Market, they are subject to the balancing market settlement.

Source and Sink in the Real-Time Market

Real-Time Market transaction sources and sinks are determined through a combination of defaulted values and market participant selections.

- **Real-Time Market Imports.** For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is DUK and the POD is PJM, the source would initially default to DUK's Interface pricing point (i.e. SouthIMP). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.

- **Real-Time Market Exports.** For a real-time export energy transaction, when a market participant selects the POR and POD on their OASIS reservation, the sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is DUK, the sink would initially default to DUK's Interface pricing point (i.e. SouthEXP). At the time the energy is scheduled, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the SouthEXP Interface, the sink would then default to that new interface. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.

- **Real-Time Market Wheels.** For a real-time wheel through energy transaction, when a market participant selects the POR and POD on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is DUK and the POD is NYIS, the source would initially default to DUK's Interface pricing point (i.e. SouthIMP), and the sink would initially default to NYIS's Interface pricing point (i.e. NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Source and Sink in the Day-Ahead Market

Day-Ahead Market transaction sources and sinks are determined solely by the market participants.

- **Day-Ahead Market Imports.** For day-ahead import energy transactions, the market participant chooses any import pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.

- **Day-Ahead Market Exports.** For day-ahead export energy transactions, the market participant chooses any export pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.

- **Day-Ahead Market Wheels.** For day-ahead wheel through energy transactions, the market participant chooses any import pricing point and export pricing point they wish to have associated with their transaction. These selections are made through the EES user interface.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed under several conditions, including economic and reliability considerations.

There are three types of economic curtailments: curtailments of dispatchable schedules, OASIS designation curtailments (willing to pay congestion or not willing to pay congestion), and market participant self-curtailments. System reliability curtailments are termed TLRs or transmission loading relief.

A dispatchable external energy transaction (also known as "real-time with price") is one in which the market participant designates a floor or ceiling price on their external transaction from which they would like the energy to flow. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface where the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP at which they are willing to sell energy into PJM). An export dispatchable schedule specifies the maximum LMP at the interface where the market participant wishes to purchase energy from PJM.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If the system operator does not feel that the transaction will be economic, they will elect to not load the transaction, or to curtail the dispatchable transaction at the top of the next hour if it has already been loaded. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. If the resulting hourly integrated prices are such that the transaction should not have been loaded, the transaction will be made whole through operating reserve credits.

Not willing to pay congestion transactions should be curtailed if there is realized congestion between the designated source and sink.

Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero.

A market participant may curtail their transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

Interface Pricing

Interface pricing points differ from interfaces. (See Table 4-7 for a list of active interfaces in 2009. Figure 4-4 shows the approximate geographic location of the interfaces.)

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[32] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area and Load Control Area as specified on the NERC Tag. According to the *PJM Interface Price Definition Methodology* dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[33] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. The challenge is to create interface prices, composed of external pricing points, that accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[34] Table 4-8 presents the interface pricing points used during 2009.

Table 4-7 Active interfaces: Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND									Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	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
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

32 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1,369 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

33 See "PJM Interface Pricing Definition Methodology." (September 29, 2006) (Accessed January 20, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx> (33 KB).

34 See the *2007 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

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

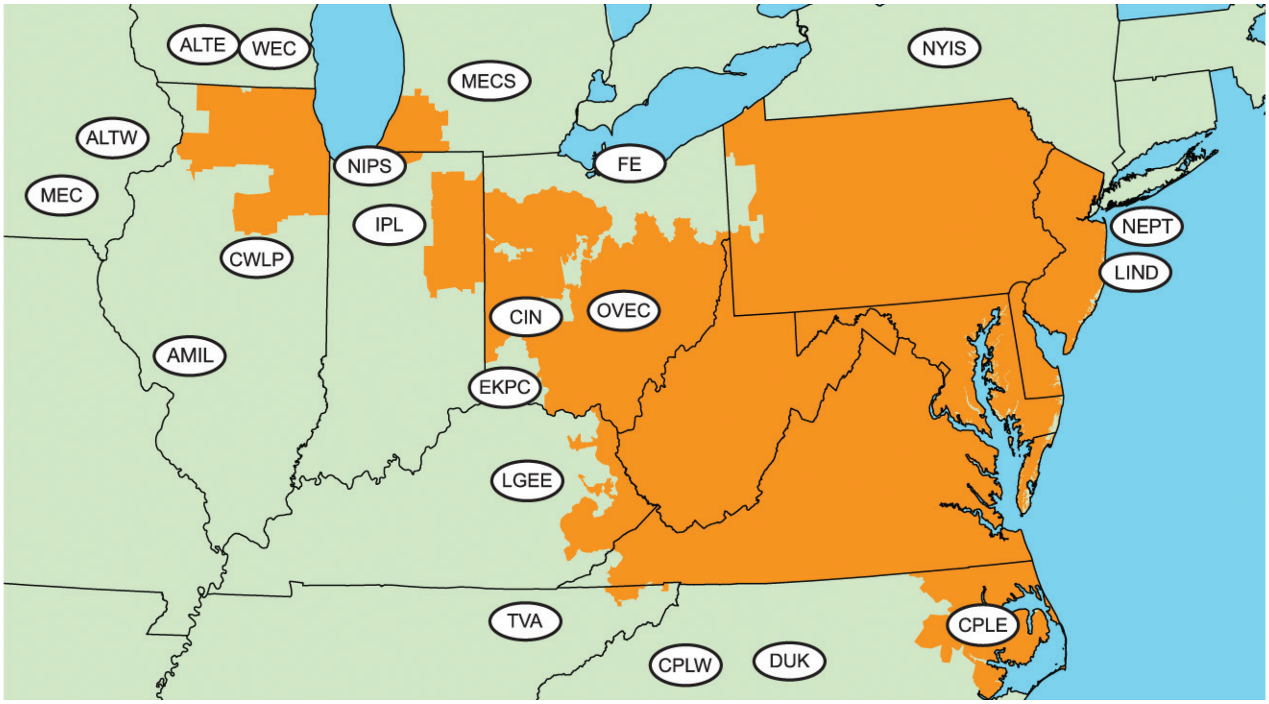


Table 4-8 Active pricing points: 2009

PJM 2009 Pricing Points			
LIND	MICHFE	MISO	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO
OVEC	SOUTHEXP	SOUTHIMP	

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

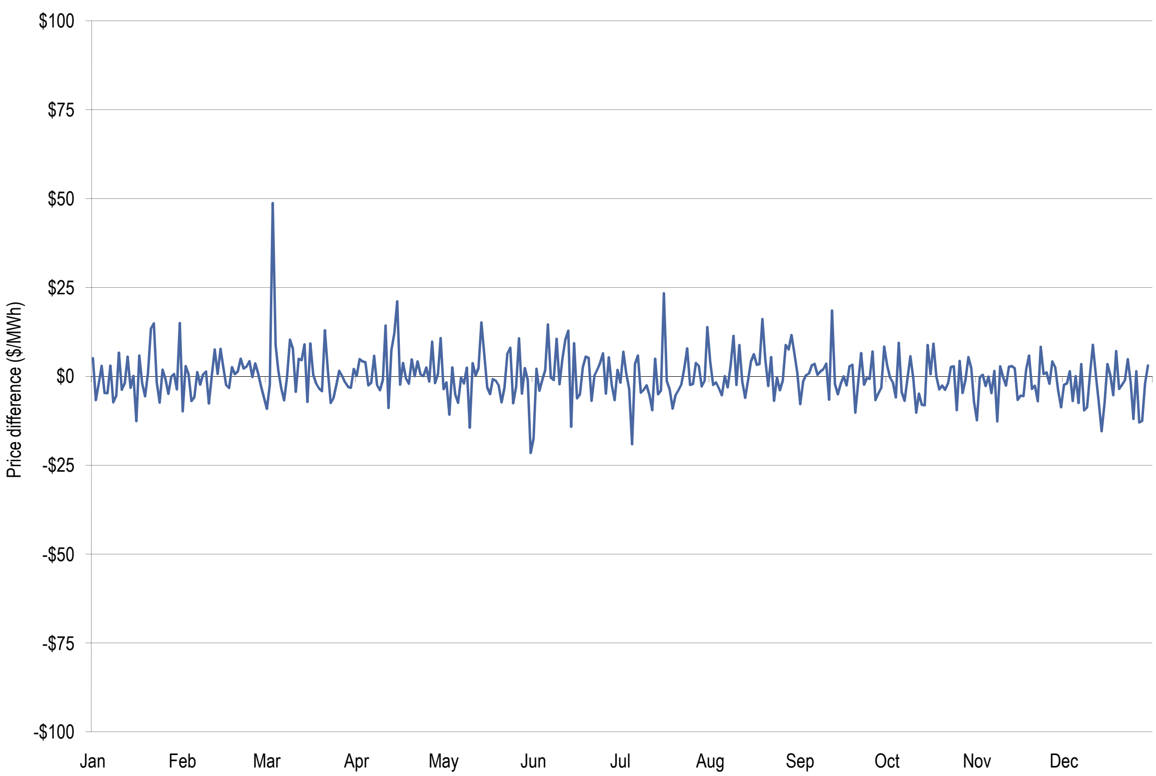
During 2009, Real-Time Market prices at the borders between PJM and the Midwest ISO and between PJM and the NYISO were consistent with competitive forces.

PJM and Midwest ISO Interface Prices

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 Interface 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 the Midwest ISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into the Midwest ISO from PJM would receive the MISO/PJM Interface price. PJM and the 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[35] within the Midwest ISO to calculate the PJM/MISO Interface price, while the Midwest ISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[36]

The 2009 real-time hourly average interface prices for PJM/MISO and MISO/PJM were $29.67 and $29.68. The simple average difference between the real-time MISO/PJM Interface price and the PJM/MISO Interface price decreased from $1.17 per MWh in 2008 to $0.01 per MWh in 2009.[37] This is consistent with the fact that PJM net exports in 2009 were significantly lower than in 2008, as the price convergence in 2009 did not provide the incentives to purchase power from PJM and export to or through the Midwest ISO. (In the Real-Time Market in 2008, gross exports were 15,890.0 GWh vs. 12,774.9 GWh in 2009.) (See Figure 4-5.)

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2009



The simple average interface price difference does not reflect the underlying hourly variability in prices. 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.

35 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1,369 KB). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

36 Based on information obtained from the Midwest ISO Extranet (January 15, 2010) <http://extranet.midwestiso.org>.

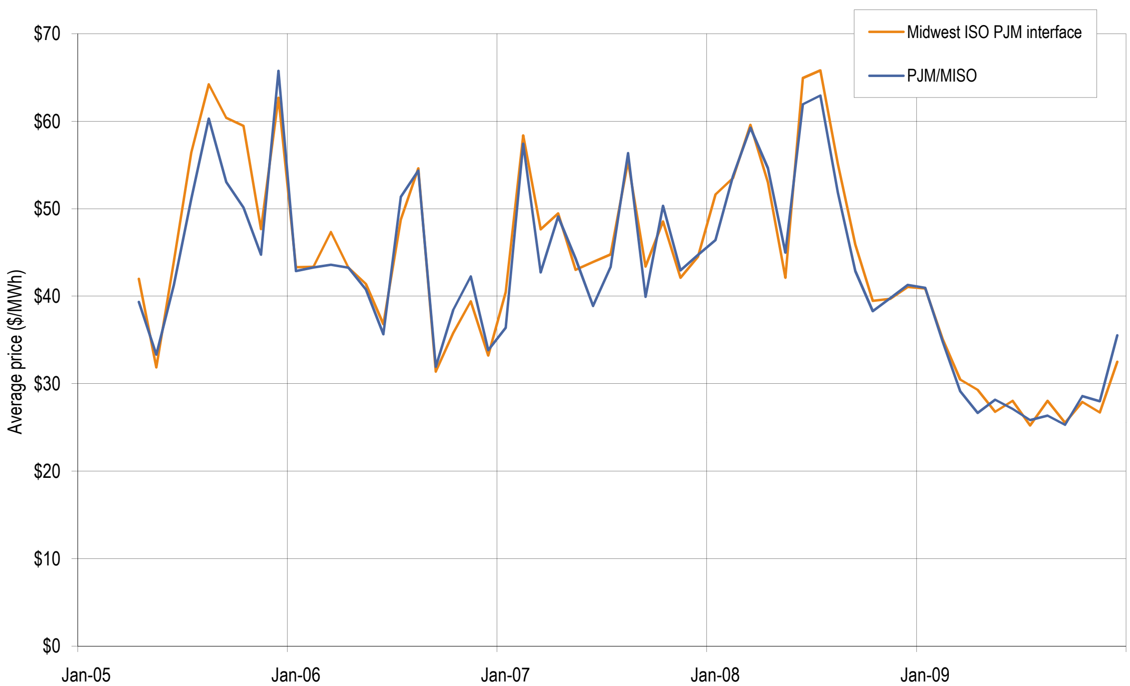
37 Table 4-9 in the *2008 State of the Market Report for PJM* incorrectly shows the simple average difference between the PJM and MISO Interface price as -$0.76. The report and Figure 4-9 correctly indicate that the simple average price difference was -$1.17 for 2008.

During 2009, the difference between the real-time PJM/MISO Interface price and the real-time MISO/PJM Interface price fluctuated between positive and negative about eight times per day. The standard deviation of the hourly price was $13.79 for the PJM/MISO Interface price and $17.83 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $17.14. The average of the absolute value of the hourly price difference was $9.94. 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 the real-time monthly average hourly PJM/MISO and MISO/PJM Interface prices during the 2009 period. (See Figure 4-6.)

Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through December 2009



The difference in real-time PJM and MISO Interface prices can also be measured by comparing the LMP for pairs of generating units that are located close together but on opposite sides of the border between PJM and the Midwest ISO and by comparing the LMP for jointly owned units that participate in both markets. The MMU compared two pairs of units and two jointly owned units. The LMP differences were compared over the calendar years 2008 and 2009.

Table 4-9 shows that in 2008 and 2009 both unit pairs and jointly owned units had real-time LMP differences larger than the difference at the PJM/MISO Interface, while the marginal congestion component and the marginal loss components of the total LMP were smaller than the difference at the PJM/MISO Interface. While the sample is not adequate to permit general conclusions, the data from these units indicate that actual price differences at the border between PJM and the Midwest ISO have varied from the interface pricing differences. Price differences at Kincaid reflect actual operational issues that make the price adjustment process less continuous.

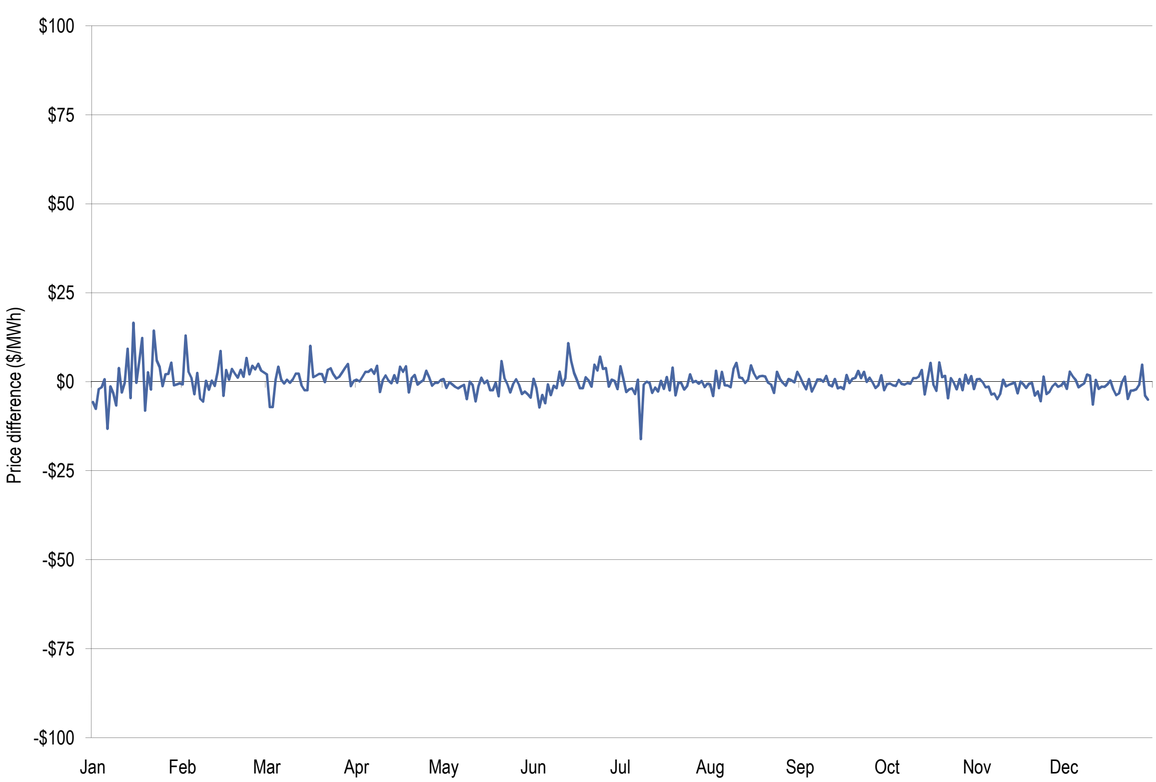
Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): Calendar years 2008 and 2009

	2008			2009		
	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$8.26	($6.56)	($2.86)	$4.81	($2.65)	($2.06)
Beaver Valley (PJM) & Mansfield (MISO)	$0.89	($14.42)	($2.38)	$3.22	($4.92)	($1.38)
Miami Fort (PJM) & (MISO)	$1.25	($12.27)	($4.16)	$2.20	($4.64)	($2.70)
Stuart (PJM) & (MISO)	$0.87	($12.04)	($4.77)	$1.81	($4.63)	($3.07)
PJM/MISO Interface	($1.16)	($15.34)	($3.51)	$0.01	($6.94)	($2.58)

LMP: Locational Marginal Price, MCC: Marginal Congestion Component, MLC: Marginal Loss Component

The 2009 day-ahead hourly average interface prices for PJM/MISO and MISO/PJM were $29.94 and $29.91. The simple average difference between the day-ahead MISO/PJM Interface price and the PJM/MISO Interface price decreased from $0.62 in 2008 to $0.03 in 2009. (See Figure 4-7.) The day-ahead net gross exports to the Midwest ISO increased from 31,051.9 GWh in 2008 to 35,123.1 GWh in 2009.

Figure 4-7 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): Calendar year 2009



During 2009, the difference between the day-ahead PJM/MISO Interface price and the day-ahead MISO/PJM Interface price fluctuated between positive and negative about five times per day. The standard deviation of the hourly price was $10.73 for the PJM/MISO price and $10.05 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $5.05. The average of the absolute value of the hourly price difference was $3.50.

In addition, there is a significant correlation between the day-ahead monthly average hourly PJM and Midwest ISO Interface prices during the 2009 period. Figure 4-8 shows this correlation between hourly PJM and Midwest ISO Interface prices.

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

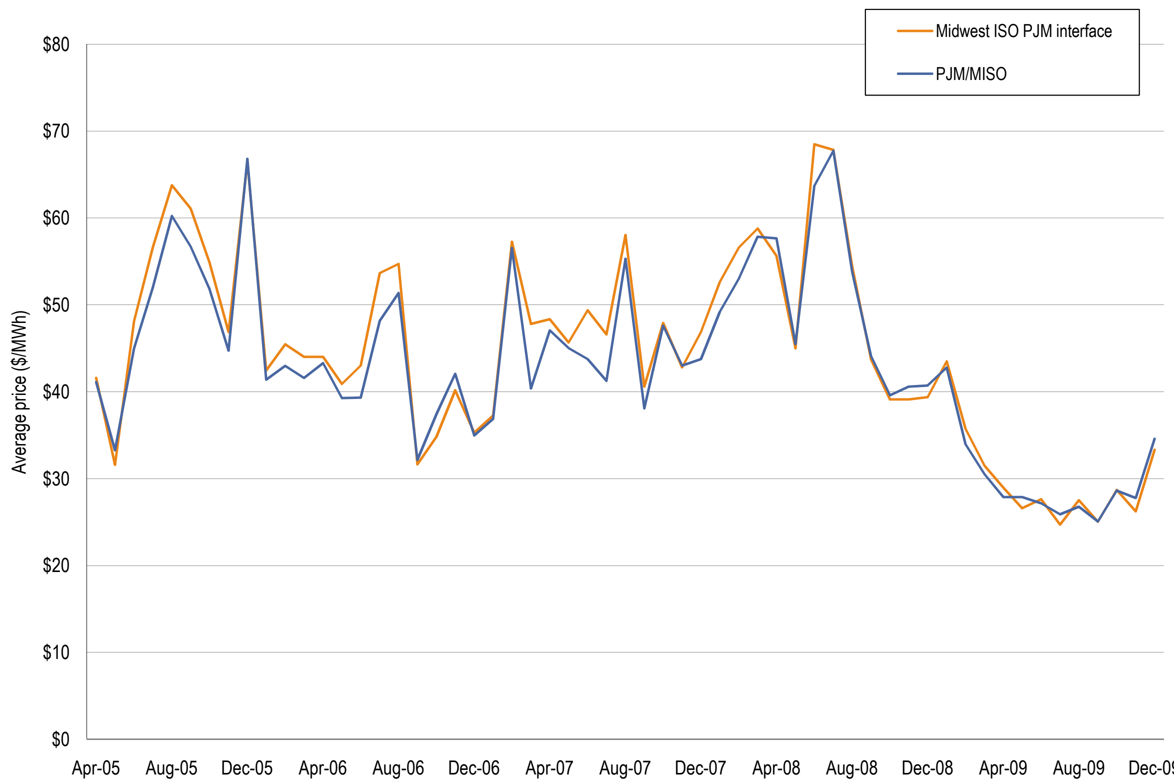


Table 4-10 shows that in 2008 and 2009 both unit pairs and jointly owned units had day-ahead LMP differences larger than the difference at the PJM/MISO Interface, while the marginal congestion component and the marginal loss components of the total LMP were smaller than the difference at the PJM/MISO Interface. While the sample is not adequate to permit general conclusions, the data from these units indicate that actual price differences at the border between PJM and the Midwest ISO have varied from the interface pricing differences. Price differences at Kincaid reflect actual operational issues that make the price adjustment process less continuous.

Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): Calendar years 2008 and 2009

	2008			2009		
	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$9.19	($3.00)	($4.25)	$4.02	($2.06)	($2.80)
Beaver Valley (PJM) & Mansfield (MISO)	$3.40	($9.88)	($3.16)	$2.48	($4.72)	($1.67)
Miami Fort (PJM) & (MISO)	($0.05)	($11.17)	($5.32)	$1.87	($3.85)	($3.16)
Stuart (PJM) & (MISO)	($0.56)	($11.00)	($6.00)	$1.40	($3.87)	($3.61)
PJM/MISO Interface	($0.62)	($12.51)	($4.55)	($0.03)	($5.75)	($3.16)

LMP: Locational Marginal Price, MCC: Marginal Congestion Component, MLC: Marginal Loss Component

PJM and NYISO Interface Prices

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-RTO/ISO power flows, and those price differentials.

PJM operators must verify all requested energy schedules with its neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the NYISO, all neighboring balancing authorities handle transaction requests the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, they utilize their Market Information System (MIS) as their primary scheduling tool. The NYISO's Real-Time Commitment (RTC) tool evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. This evaluation accepts or denies individual transactions in whole or in part. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour (as discussed in the "Ramp" section).

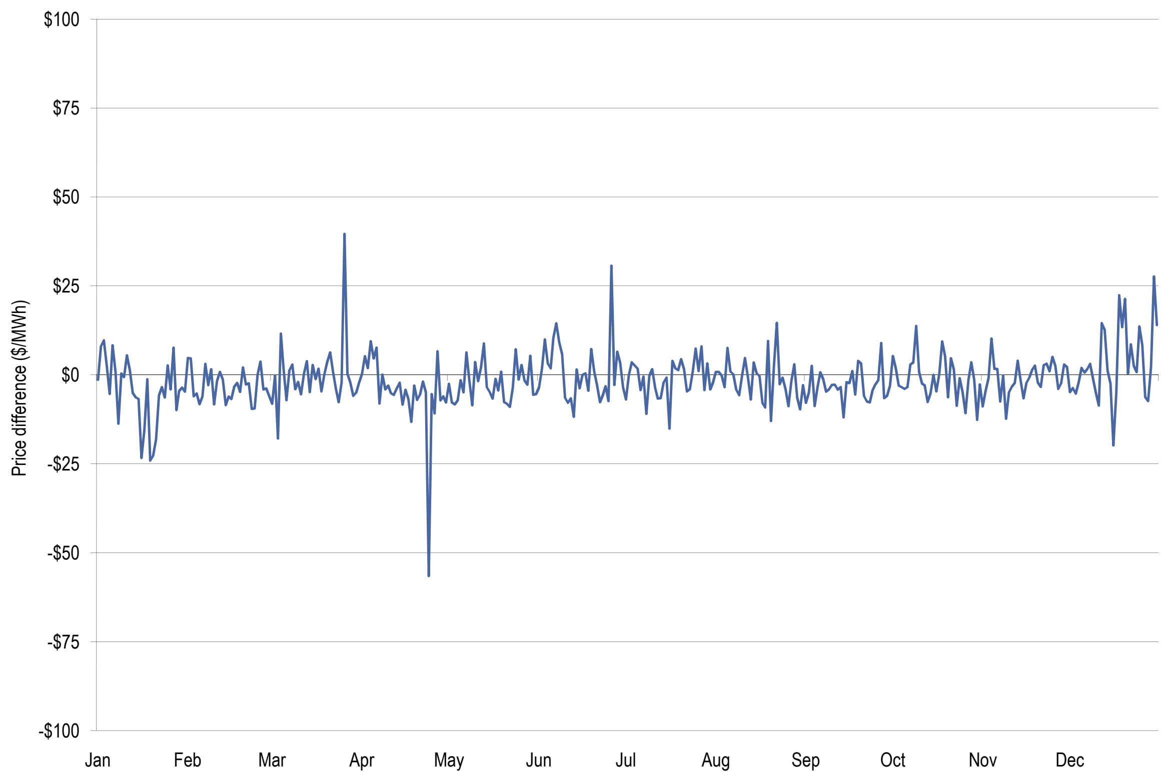
PJM's price for transactions with the NYISO (excluding those transactions across the Neptune and Linden lines), termed the NYIS Interface pricing point by PJM, represents the value of power at the PJM/NYISO border, as determined by the PJM market. PJM defines its NYIS Interface pricing point using two buses.[38] 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

38 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1,369 KB). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

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 load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

The 2009 real-time hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $37.37 and $39.16. The simple average difference between the PJM/NYIS Interface price and the NYISO/PJM proxy bus price increased from $0.86 per MWh in 2008 to $1.79 per MWh in 2009 (See Figure 4-9.) PJM's net export volume to the NYIS Interface for 2009 was significantly higher than in 2008. This is consistent with the fact that the PJM/NYIS price was, on average, lower than the NYISO/PJM price in 2009.

Figure 4-9 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2009



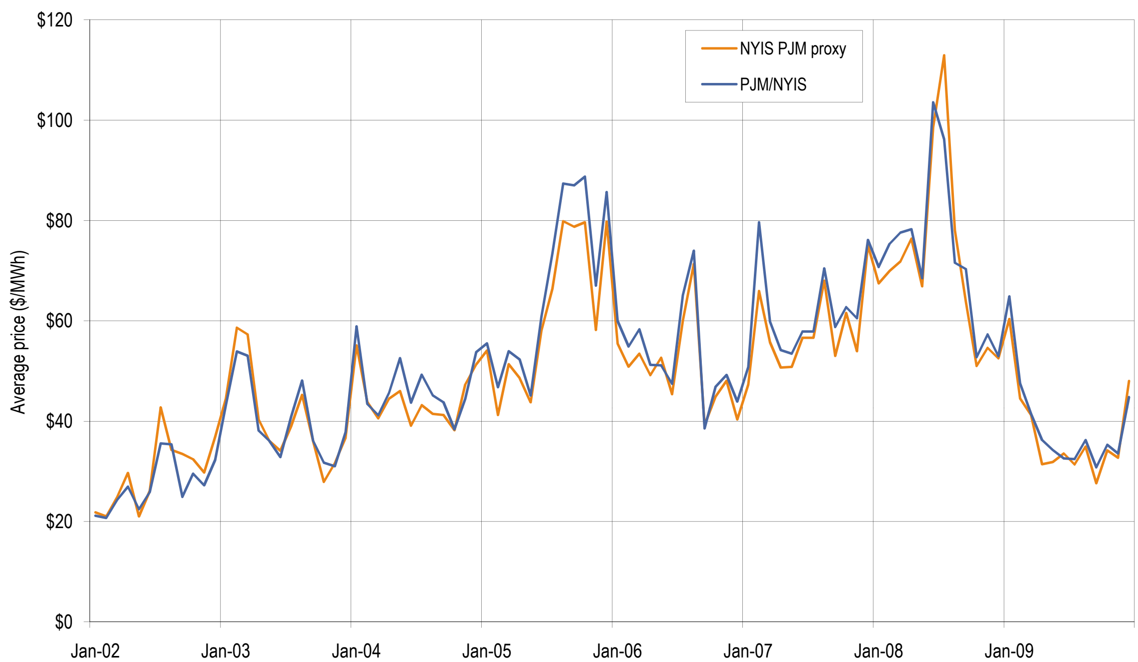
The simple average interface price difference does not reflect the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

The difference between the real-time PJM/NYIS Interface price and the real-time NYISO/PJM proxy bus price continued to fluctuate between positive and negative about eight times per day during 2009 as it has since 2003. The standard deviation of hourly price was $18.69 in 2009 for the PJM/NYIS Interface price and $27.37 in 2009 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $25.80 in 2009. The average of the absolute value of the hourly price difference was $11.58 in 2009. Absolute values reflect 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 price differences 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.

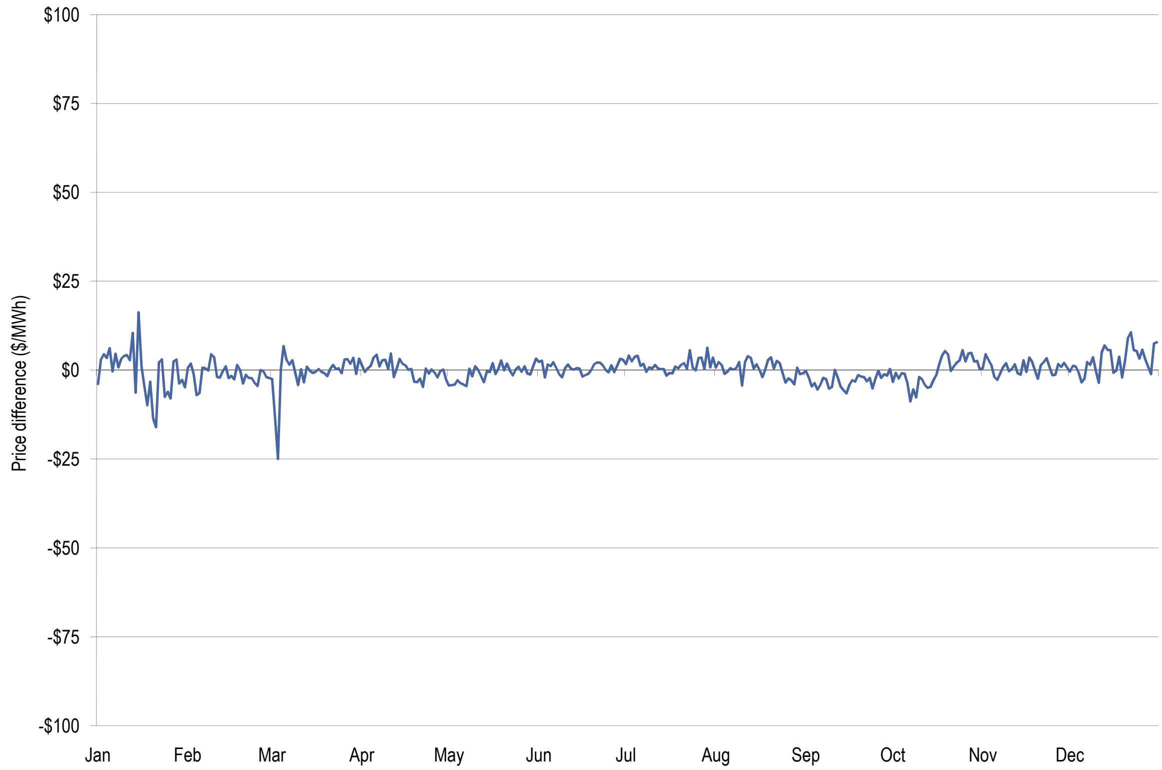
There has been a significant correlation between real-time monthly average hourly PJM/NYIS Interface and NYISO's PJM proxy bus prices during the entire period 2002 to 2009. (See Figure 4-10.)

Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through December 2009



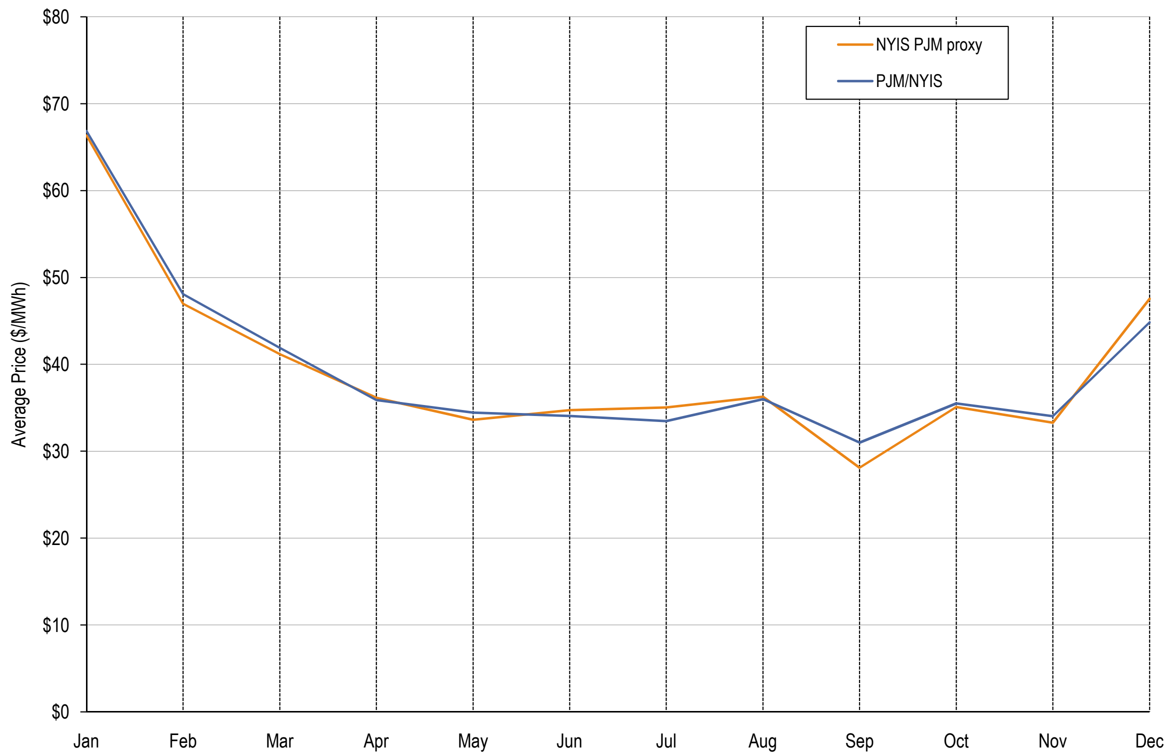
The 2009 day-ahead hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $39.53 and $39.66. The simple average difference between the day-ahead PJM/NYISO Interface price and the NYISO/PJM proxy bus price decreased from $2.79 in 2008 to $0.13 in 2009. (See Figure 4-11.) The day-ahead net gross exports to the NYISO decreased from 6,500.0 GWh in 2008 to 5,806.6 GWh in 2009.

Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2009



There has been a significant correlation between day-ahead monthly average hourly PJM/NYIS Interface and NYISO's PJM proxy bus prices during 2009. (See Figure 4-12.)

Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar year 2009



Summary of Interface Prices between PJM and Organized Markets

The key features of the real-time and day-ahead PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-13 and Figure 4-14 including average prices and measures of variability.

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: Calendar year 2009

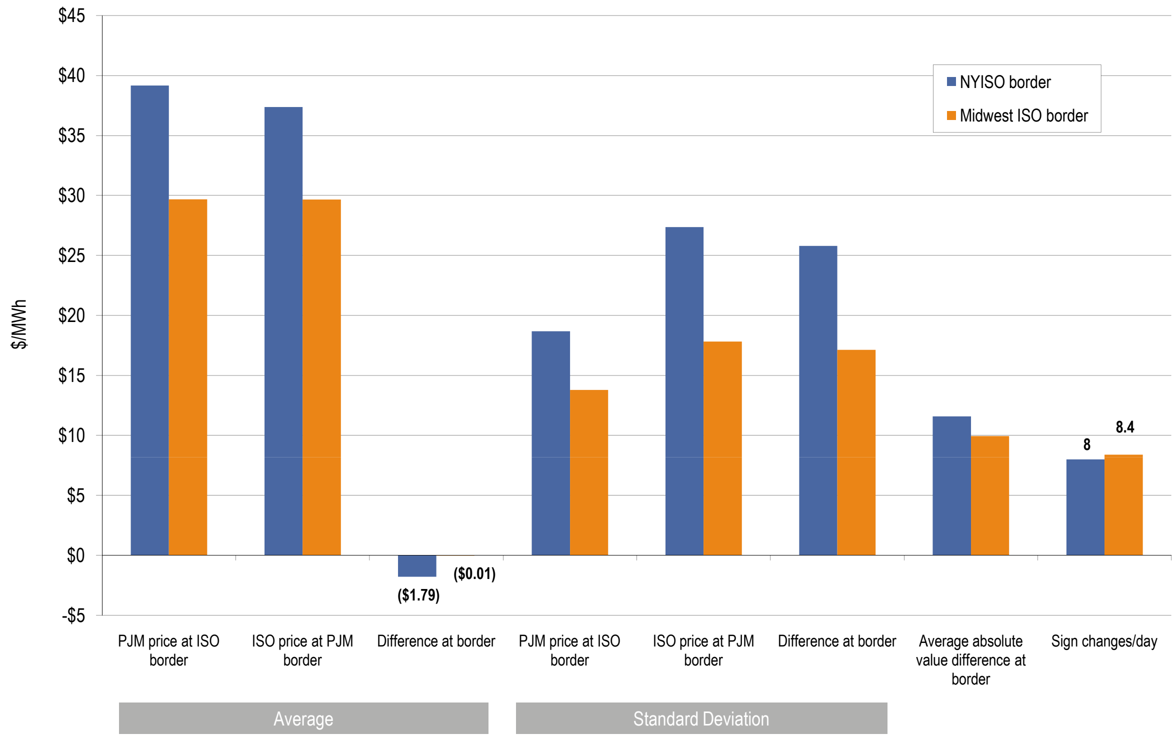
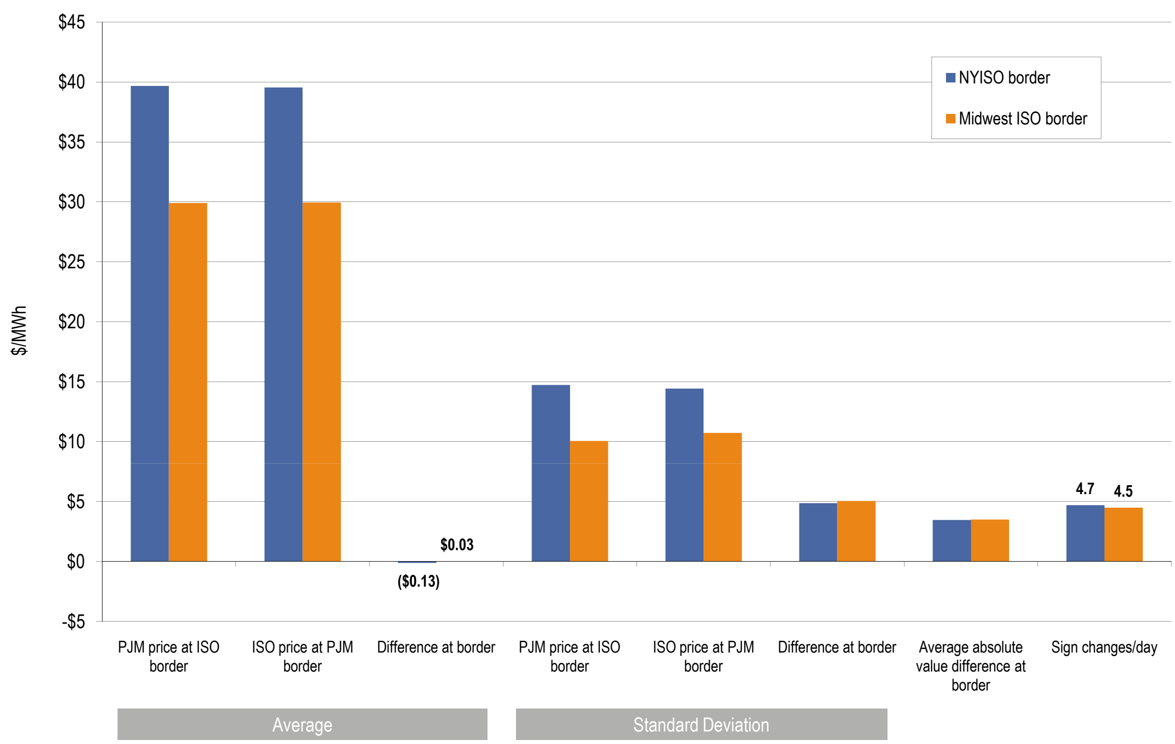


Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: Calendar year 2009



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 a reliability agreement with the NYISO, an implemented operating agreement with the Midwest ISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., that is not yet fully implemented, and a reliability coordination agreement with VACAR South.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)

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, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued into 2009. By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order." [39] After working in collaboration with PJM, the Midwest ISO and the IESO, including an opportunity to comment from their stakeholders and market monitors, the NYISO filed on January 12, 2010, a *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.*[40] The MMU filed comments on November 13, 2009.[41]

PJM and Midwest ISO Joint Operating Agreement

The market to market coordination between PJM and the Midwest ISO continued in 2009. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculate an LMP 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 Interface 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 Interface pricing point.

In 2009, the Midwest ISO requested that PJM review the components of the Congestion Management Process (CMP) to verify data accuracy. During this review, it was found that some data inputs to the market flow calculator were incorrect during the period from April 2005 through June 2009. The resulting inaccuracies in the market flow calculation meant that the Midwest ISO received less compensation than appropriate. 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 shortfall. PJM reported an estimate of 77.5 million dollars.[42]

39 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

40 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" (January 12, 2010) (Accessed January 25, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

41 See "IMM Comments on Draft Loop Flow Recommendations of the Broader Regional Markets" (November 13, 2009) (Accessed January 21, 2010) <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_Comments_on_Draft_Loop_Flow_Recommendations_20091113.pdf> (86 KB).

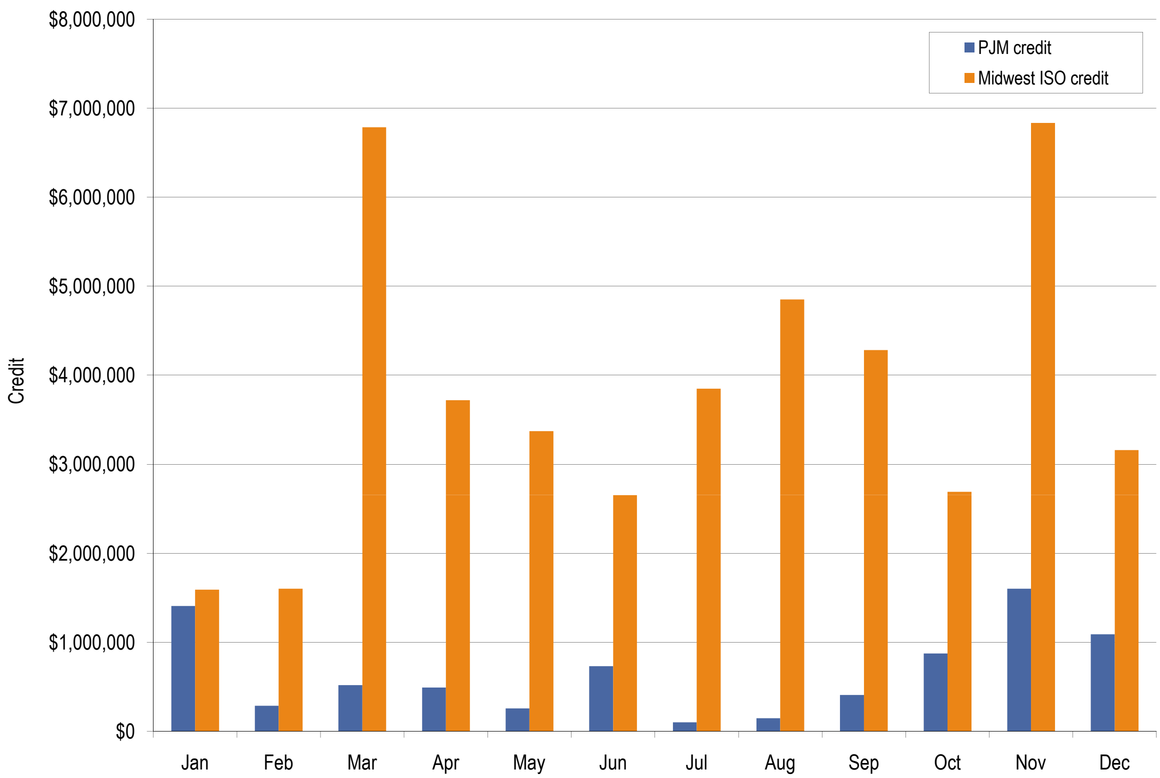
42 See PJM. "PJM/MISO Market Flow Calculation Error" (September 10, 2009) (Accessed January 15, 2010) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

As of December 31, 2009, PJM and the Midwest ISO had not agreed upon a method to estimate the amount for the entire period. Differences have also emerged over how the parties are administering the JOA, such as the use by the Midwest ISO of proxy flowgates. This practice, if confirmed, measured and determined inconsistent with the JOA, would mean that the Midwest ISO received more compensation than appropriate. The parties are currently engaged in a confidential FERC mediated settlement process to resolve these issues.

Generating units that do not respond to RTO dispatch signals may contribute to the need for PJM and the Midwest ISO to implement market to market redispatch and result in payments under the JOA. The MMU recommends that the JOA be modified so as to eliminate payments between RTOs in the event that payments result from the failure of generating units to respond to appropriate pricing signals.

The market to market operations resulted both in the Midwest ISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each reciprocal coordinated flowgate (RCF) used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE. Figure 4-15 presents the monthly credits each organization received from redispatching for the other. A PJM credit is a payment by the Midwest ISO to PJM and a Midwest ISO credit is a payment by PJM to the Midwest ISO. The largest payments from PJM to the Midwest ISO during 2009 were the result of redispatch by the Midwest ISO to relieve congestion on the Crete-St Johns Tap 345 kV for the loss of Dumont-Wilton Center 765 kV line. Total PJM payments to the Midwest ISO were $45.4 million, a 23 percent decrease from the 2008 level. The largest payments from the Midwest ISO to PJM during 2009 were the result of redispatch by PJM to relieve congestion on the Paddock-Townline 138 for the loss of Paddock-Blackhawk 138 line. Total Midwest ISO payments to PJM were $7.9 million, a 40 percent decrease from the 2008 level.

Figure 4-15 Credits for coordinated congestion management: Calendar year 2009



PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement (JRCA)

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 during 2009. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining 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 remains in effect. Since PEC is not a market system, the coordination agreement between PEC and PJM is similar to the agreement that existed between the Midwest ISO and PJM during the first phase of their JOA. The ATC coordination that had been expected to be completed during the first half of 2006 remained under development during 2009. PJM and Progress continued to develop the congestion management process as required by the agreement. A phased approach to development of congestion management is being discussed.

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems. The agreement remained in effect through 2009.

Other Agreements with Bordering Areas

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 the NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. 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 two companies, PJM and the NYISO.[43] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[44] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[45] PJM continued to operate under the terms of the protocol through 2009.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City. Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

The protocol allows Con Edison to elect up to the flow specified in 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

43 111 FERC ¶61,228 (2005).
44 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).
45 FERC Order Denying Rehearing, Order, Docket No. EL02-23 (August 15, 2007).

costs 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.

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 2009, PSE&G's revenues were less than its congestion charges by $5,417 after adjustments. (Revenues exceeded its charges by $13,768 in 2008.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2009, Con Edison's congestion credits were $232,744 less than its day-ahead congestion charges. Con Edison also had a day-ahead congestion credit. With appropriate adjustments accounted for, the result was that Con Edison's total charges exceeded its congestion credits by $251,102. (Credits had been $213,535 less than charges in 2008.) (See Table 4-11.)

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$251,102 in 2009. The parties should address this issue.

Table 4-11 Con Edison and PSE&G wheeling settlement data: Calendar year 2009

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total Congestion Credit	$1,488,379	$894	$1,489,274	$4,119,216	$0	$4,119,216
Congestion Credit			$1,255,635			$4,099,812
Adjustments			$484,741			$13,987
Net Charge			($251,102)			$5,417

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. This occurred in 2 percent of the hours in 2009.

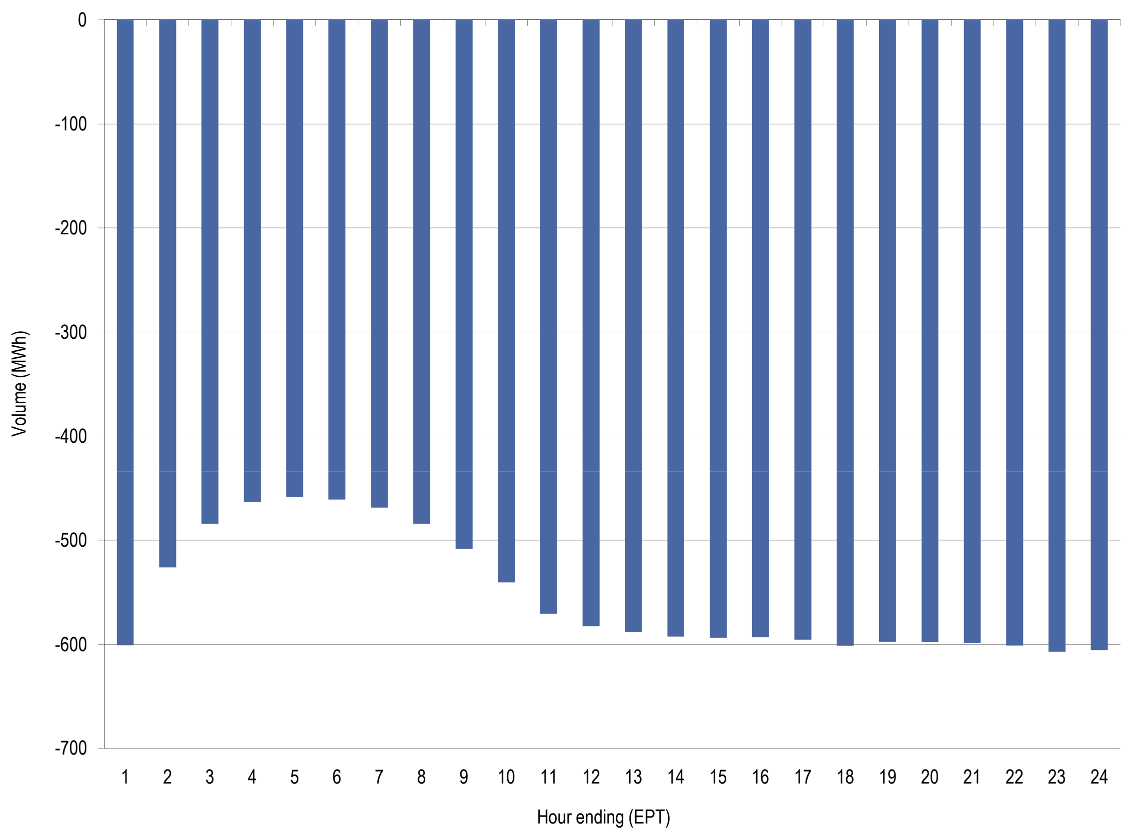
Neptune Underwater Transmission Line to Long Island, New York

On July 1, 2007, a 65-mile, DC transmission line from Sayreville, New Jersey, to Nassau County on Long Island via undersea and underground cable was placed in service, providing an additional connection between PJM and the NYISO. This is a merchant 230 kV transmission line with a capacity of 660 MW. While the Neptune line is a bidirectional facility, Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[46] For 2009, the total real-time scheduled net exports on the Neptune line were 4,961 GWh while the day-ahead scheduled net exports were 5,064 GWh. Figure 4-16 shows the average flow, by hour of the day, on the Neptune line for the calendar year 2009. The average hourly flow during 2009 was -555 MWh. For the calendar year 2009, the average hourly PJM/NEPT Interface price was $41.94

46 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed January 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,884 KB).

per MWh, while in the NYISO the Neptune bus average price was $49.24 per MWh. Although the yearly average interface price differentials are consistent with flows from PJM to the NYISO, the PJM/NYIS Interface price was lower than the NYISO Neptune bus price in 37.0 percent of the hours in 2009.

Figure 4-16 Neptune hourly average flow: Calendar year 2009

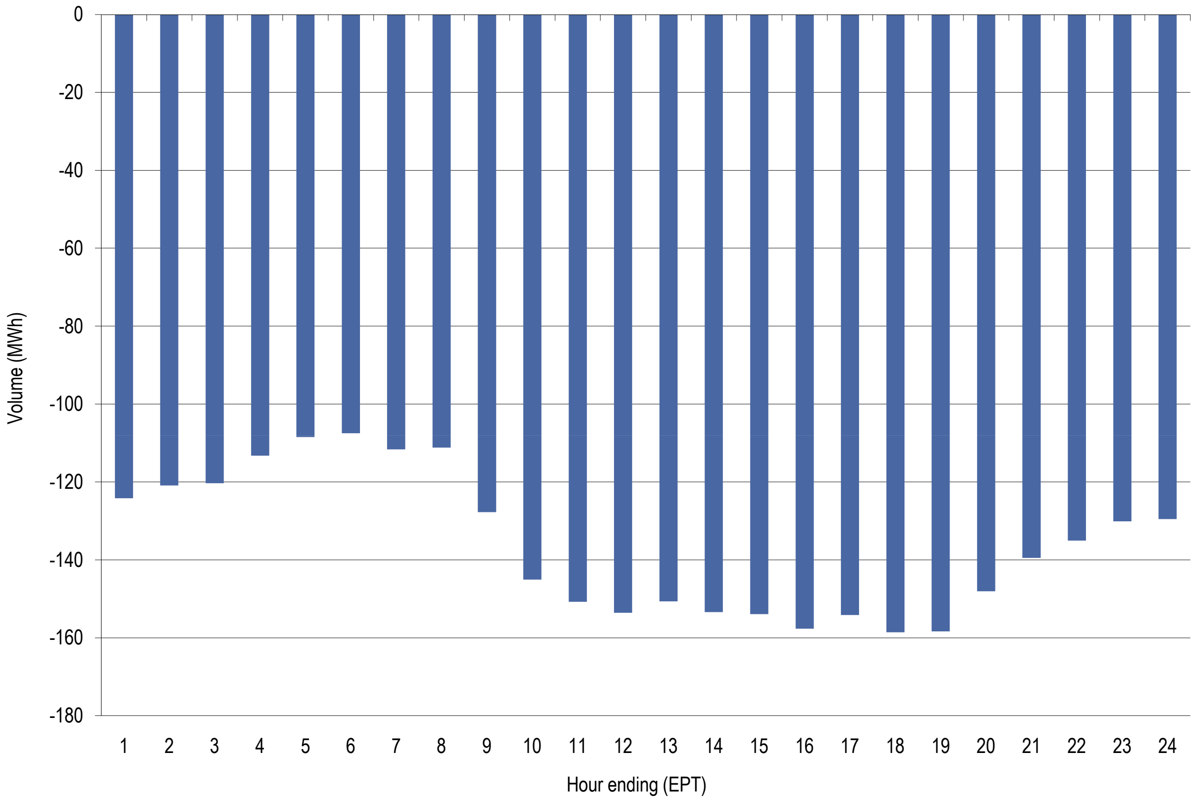


Linden Variable Frequency Transformer (VFT) facility

On November 1, 2009, the Linden VFT facility was placed in service, providing an additional connection between PJM and the NYISO. A variable frequency transformer is a technology which allows for fast responding continuous bidirectional power flow control, similar to that of a PAR. The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line, with a capacity of 300 MW. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[47] Figure 4-17 shows the average flow, by hour of the day, on the Linden line for the calendar year 2009. The average hourly flow during 2009 was -136 MWh.[48] For the calendar year 2009, the average hourly PJM/LIND Interface price was $38.19 per MWh, while in the NYISO the Linden VFT bus average price was $43.22 per MWh. Although the yearly average interface price differentials are consistent with flows from PJM to the NYISO, the PJM/LIND Interface price was lower than the NYISO Linden VFT bus price in 40.1 percent of the hours in 2009.

47 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed January 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,884 KB).
48 The average hourly flow reported for the Linden Variable Frequency Transformer includes the scheduled flow during the testing period that occurred starting in September 2009.

Figure 4-17 Linden hourly average flow: September through December 2009



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 defined as the difference between actual and scheduled power 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 system actual and scheduled flow 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 can also exist as a result of transactions within a market based area in the absence of an explicit agreement to price congestion. 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.

Loop flows are a significant concern. Loop flows can 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.

The fact that total PJM net actual interface flows were close to net scheduled interface flows, on average for 2009 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 4-12.) 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 balancing authorities.

During 2009, for PJM as a whole, net scheduled and actual interchange differed by 2.2 percent. (See Table 4-12.) Actual system net imports were 274 GWh, 6 GWh more than the scheduled total net imports of 268 GWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 10,821 GWh exceeding scheduled imports of 3,620 GWh by 14,441 GWh or 399 percent, an average of 1,649 MW during each hour of the year. At the PJM/CPLE Interface, scheduled flows were exports of 747 GWh and actual flows were imports of 7,664 GWh, creating an imbalance of 8,411 GWh or 1126 percent, an average of 960 MW during each hour of the year.

Table 4-12 Net scheduled and actual PJM interface flows (GWh): Calendar year 2009

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	7,664	(747)	8,411	(1126%)
CPLW	(1,793)	(683)	(1,110)	163%
DUK	(2,728)	398	(3,126)	(785%)
EKPC	550	(674)	1,224	(182%)
LGEE	1,377	1,016	361	36%
MEC	(2,667)	(1,606)	(1,061)	66%
MISO	(6,291)	901	(7,192)	(798%)
ALTE	(5,561)	(760)	(4,801)	632%
ALTW	(2,370)	(1,128)	(1,242)	110%
AMIL	8,198	83	8,115	9777%
CIN	3,117	2,055	1,062	52%
CWLP	(560)	-	(560)	0%
FE	(1,981)	(2,418)	437	(18%)
IPL	2,441	166	2,275	1370%
MECS	(10,821)	3,620	(14,441)	(399%)
NIPS	(2,149)	(342)	(1,807)	528%
WEC	3,395	(375)	3,770	(1005%)
NYISO	(8,331)	(11,035)	2,704	(25%)
LIND	(349)	(349)	-	0%
NEPT	(4,863)	(4,863)	-	0%
NYIS	(3,119)	(5,823)	2,704	(46%)
OVEC	8,493	12,538	(4,045)	(32%)
TVA	4,000	160	3,840	2400%
Total	274	268	6	2.2%

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 (-14,441 GWh during 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 (3,840 GWh during 2009 and 4,065 GWh during the calendar year 2008). 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

Figure 4-18 and Figure 4-19 illustrate the reduction in the previously 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 to its largest volumes through the summer of 2006. A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP). At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. (The average difference between LMP at the Southeast pricing points and the SouthEXP pricing point was $2.61 in 2009 and the average difference between LMP at the Southwest pricing points and the SouthEXP pricing point was -$1.42 in 2009. In other words, it was more expensive to buy from PJM for export to the south under the old pricing for Southeast pricing point and less expensive to buy from PJM for export to the south under the old pricing for the Southwest pricing point.) These agreements remain in place. The MMU recommends that these agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

Despite some improvements, significant loop flows persist. While the SouthIMP and SouthEXP pricing points have replaced the Southeast and Southwest pricing points Figure 4-18 and Figure 4-19 are included for comparison.

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match pricing with physical flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SWPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SWPP, through the Midwest ISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (the Midwest ISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SWPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both the Midwest ISO border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows).

Figure 4-18 Southwest actual and scheduled flows: January 2006 through December 2009

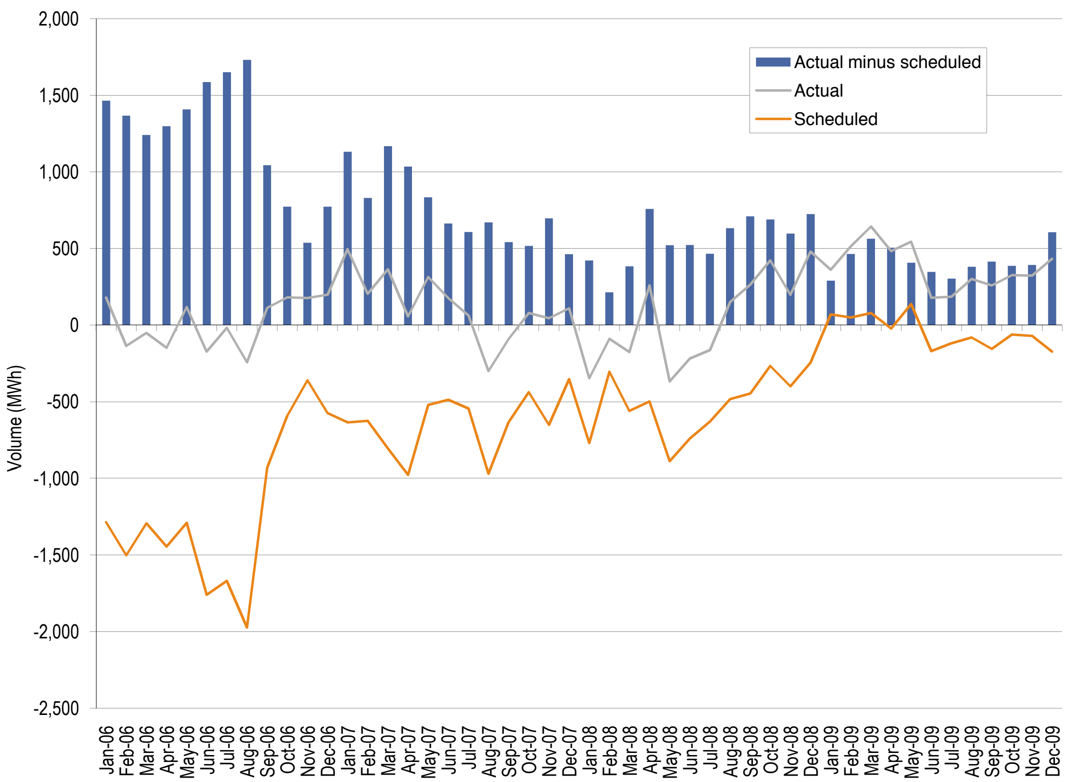
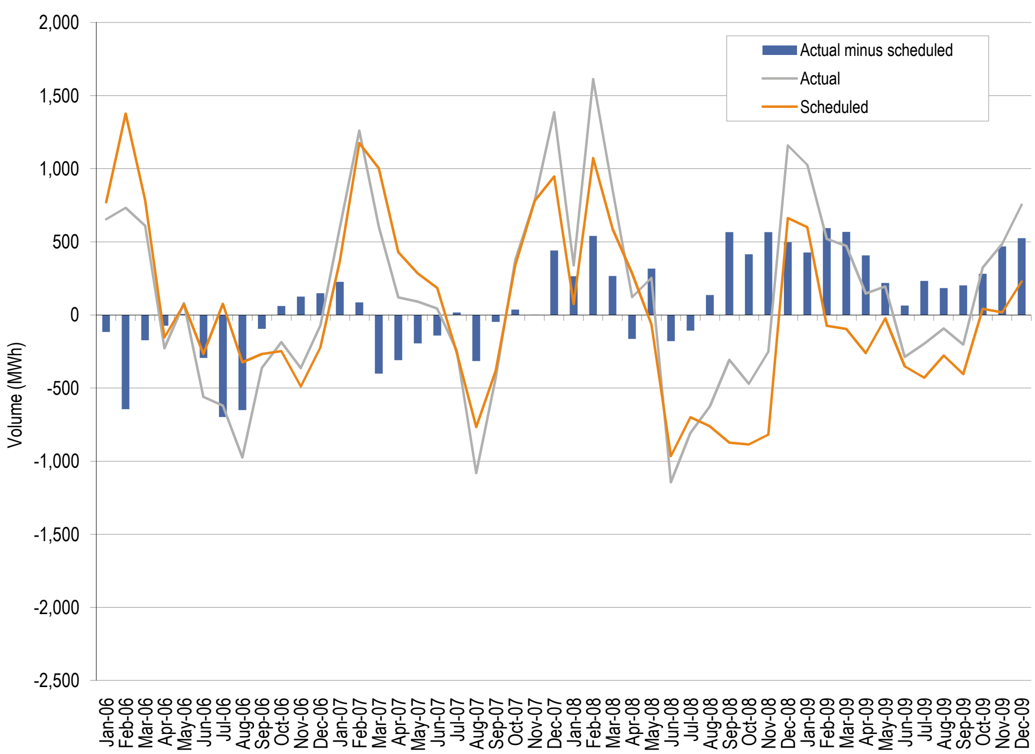


Figure 4-19 Southeast actual and scheduled flows: January 2006 through December 2009



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.[49] PJM's interface pricing calculations correctly reflected the actual power flows, but the 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.

By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[50]

Consistent with the Commission's direction, during the third quarter of 2009, the NYISO convened the Broader Regional Markets group, which included representatives from PJM, the NYISO, the Midwest ISO and the IESO, to develop a solution to the northeastern loop flow issues. The group solicited comments from stakeholders and the market monitors. The MMU filed comments on November 13, 2009.[51]

The group developed several recommendations, including the use of PARs to control energy flows, a buy-through congestion methodology, the development of a new tool, using existing functionality within NERCs Interchange Distribution Calculator (IDC), to visualize the loop flows and an interregional transaction coordination approach to align business rules across the northeast ISOs/RTOs. On January 12, 2010, in compliance with the Commission's directive, the NYISO submitted its *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow*.[52]

Engineering approaches to address loop flows, such as phase angle regulators and variable frequency transformers, are a means to help ameliorate loop flow issues, but they do not address the root cause of loop flows. So long as these physical solutions are used in conjunction with more comprehensive market solutions, the MMU supports cost effective investment in additional PARs for system control. With the possible exception of cost allocation issues, the use of PARs does not appear to be controversial. Engineering approaches should not serve as a basis to defer or deflect attention to the development of market solutions.

Implementing a buy-through congestion methodology is also unlikely to resolve the underlying pricing issue. PJM offers a similar product, where market participants will be allowed to continue to flow their transactions when they would otherwise be curtailed by a TLR, if they were willing to pay the congestion costs of their parallel flows affecting the PJM system. This product, called "TLR Buy-Through", was implemented in PJM in 2001. In the nearly eight years that PJM has offered this product, it has never been used by market participants. Instead, the transactions were curtailed in the TLR process to alleviate the loop flows.

49 See the *2008 State of the Market Report for PJM*, Volume II, "Section 4, Interchange Transactions"

50 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

51 See "IMM Comments on Draft Loop Flow Recommendations of the Broader Regional Markets" (November 13, 2009) (Accessed January 21, 2010) <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_Comments_on_Draft_Loop_Flow_Recommendations_20091113.pdf> (86 KB).

52 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" (January 12, 2010) (Accessed January 25, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

The report also included a recommendation that the NYISO move to a less than hourly dispatch timeframe through interregional coordination. While this recommendation did not include details, redispatch on the quarter hour would allow NYISO market participants to respond more quickly to the NYISO pricing signals.

Parallel flow visualization will provide additional information to the reliability coordinators, and will also assign a non-firm generation to load component to congestion within non-market areas. The MMU supports this project, as it will provide additional details and archived data to better analyze loop flows. However, the work of the Broader Regional Market group and the continued development of this tool within the NERC/NAESB arena do not require linkage. It would be more productive to focus on direct solutions to loop flow issues rather than the already ongoing development of loosely related industry tools.

Faulty market rules, which provided incentives to market participants to schedule energy on paths inconsistent with the physical flows, were responsible for the loop flows that motivated the NYISO's initial filing in this proceeding. The solution to this problem should start with and give priority to appropriate interface pricing that reflects the actual flow of energy. Although the buy-through congestion approach also attempts to address this issue, a more cost effective solution would assign interface prices based on the Generation Control Area (GCA) for imports and Load Control Area (LCA) for exports, as designated on the NERC e-Tag. This method for interface pricing has been used by PJM and the Midwest ISO for several years, and could be implemented immediately by other RTOs/ISOs at minimal cost.

The MMU recommends that a change in the interface pricing methodology be addressed directly. The MMU recommends that the parties consider the uniform adoption of a GCA to LCA pricing methodology, similar to that used by PJM, to set transaction prices based on the actual flow of energy from source to sink. With the appropriate pricing, the incentive for market participants to schedule around specific RTOs/ISOs would be eliminated.

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Actual power flows are the metered flows at an interface for a defined period. Scheduled power flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for a balancing authority (net actual interchange) and the total scheduled flows for the balancing authority (net scheduled interchange) for a defined period. Loop flows are defined 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 system actual and scheduled flow could net to a zero difference. As an illustration, although PJM's total scheduled and actual flows differed by only 2.2 percent in 2009, much greater differences existed at individual interfaces.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority 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 can also result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows can 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 as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and non market areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (non market areas), 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 flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. NERC Tag data, dynamic schedule and pseudo-tie data and actual tie line data are required in order to analyze the differences between actual and scheduled transactions. The ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions. All data should be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

- **NERC Tag Data**

  An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag Data includes the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Additionally, complete tag data include the identity of the specific market participants.

  Currently, the MMU has obtained some NERC Tag data via a set of “Tag Dump” files. The existing Tag Dump files include many data items from the overall NERC Tag data. Included in each file are the following data items: Tag Name, Tag Start Date/Time, Tag End Date/Time, Source Security Coordinator, Sink Security Coordinator, Source Control Area, Sink Control Area, Source, sink, Transmission Start Date/Time, Transmission End Date/Time, Transmission Provider Name, Priority, Transmission Product, OASIS Reservation, MW, Point of Receipt, Point of Delivery, Energy Start Date/Time, Energy End Data/Time, Schedule MW and Active MW. Each tag dump file is created hourly, and is in csv format. The files include active tags from the hour in which the data is created and for the next 24 hours.

  The Tag Dump files do not include the following data items: tag type, complete market path, miscellaneous information (token and value fields), tag creation timing, approval timing, denial reasons, denied tags, curtailment reasons, loss provision information, individual request information, and other data items including contact information.

Of the data items not included in the Tag Dump files, the most important elements required for loop flow analysis are the complete market path and the loss provision information. These data items would complete the picture of the scheduled interchange among all balancing authorities.

- **Dynamic Schedule and Pseudo-Tie Data**

  Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

  Pseudo-ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo-ties only differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo-ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo-tie transactions are not required to be tagged. Pseudo-tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

- **Actual Tie Line Flow Data**

  An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. Additionally, the available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

- **Area Control Error (ACE) Data**

  Area Control Error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

  NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

- **Market Flow Impact Data**

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, and requests that FERC and NERC ensure that the underlying data are provided in a downloadable format to market monitors and other approved entities.

- **Generation and Load Data**

  Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities (or individual generation owners) are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

  Market areas are transparent in providing real-time load while non market areas are not. For example, PJM posts real-time load via its eDATA application. Most non market balancing authorities provide only the expected peak load on their individual web sites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. The MMU has been attempting to obtain access to this data for several years without success. Attempts to obtain the data from NERC or tagging vendors have led to denials or to the option of very expensive subscriptions that would still require obtaining approval from every entity registered in the NERC Transmission System Information Network (TSIN) due to data confidentiality agreements, including Transmission Providers and Market Participants.

Dynamic Interface Pricing

According to the *PJM Interface Price Definition Methodology*, dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[53] The weighting factors are determined in such a manner that the interface reflects actual system conditions. The topology of the transmission system is constantly changing, as generation comes on and off line, and transmission lines come in and out of service. The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified only occasionally. The MMU recommends that PJM monitor, and adjust as necessary, the buses

53 See "PJM Interface Pricing Definition Methodology." (September 29, 2006) (Accessed January 20, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx> (33 KB).

and weightings applied to the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.

TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM called fewer TLRs in 2009 than in 2008. One reason for the decrease in TLR activity in 2009 was the result of transmission line outages caused by storms and tornados in 2008. The transmission line outages in 2008 reduced the ability to control power flows via redispatch, creating the need to utilize TLRs more often in 2008. Additionally, the lighter loads seen in 2009, as compared to 2008, likely contributed to a decrease in TLR activity. PJM TLRs decreased by 14 percent, from 150 during 2008 to 129 in 2009. (See Figure 0-20.) In addition, the number of different flowgates for which PJM declared TLRs decreased from 37 during 2008 to 28 in 2009. (See Figure 0-21.) The total MWh of transaction curtailments increased by 80 percent, from 506,617 MWh in 2008 to 912,528 MWh in 2009. (See Figure 0-22.) Of the 129 TLRs called by PJM in 2009, two facilities comprised 53 percent of the total. The two facilities were:

- **15502 Nels-Electric Junction for 15616 Cher-Silv Line.** This line is located in northern Illinois.[54] TLRs were used to control the constraints (41 TLRs in 2009; 11 TLRs in 2008);

- **East Frankfort – Crete 345 kV Line for Loss of Dumont – Wilton Center 765 kV Line.** These lines are located in northern Illinois, close to the border of Indiana. TLRs on this flowgate were generally utilized to control flows across the Illinois-Indiana border through the Northern Indiana Public Service system. While PJM and the Midwest ISO work together to control these flows using the mechanisms prescribed in the JOA, the actions were not always sufficient. This flowgate resulted in the largest amount of market to market settlements in 2009. TLRs on this flowgate were used to control the constraints (28 TLRs in 2009; 35 TLRs in 2008).

The Midwest ISO called significantly fewer TLRs in 2009 than in 2008. The Midwest ISO TLRs decreased by about 36 percent, from 599 during 2008 to 381 in 2009. (See Figure 4-20.)

54 The reasons for the high levels of TLRs on this flowgate are considered confidential.

Figure 4-20 PJM and Midwest ISO TLR procedures: Calendar years 2008 and 2009

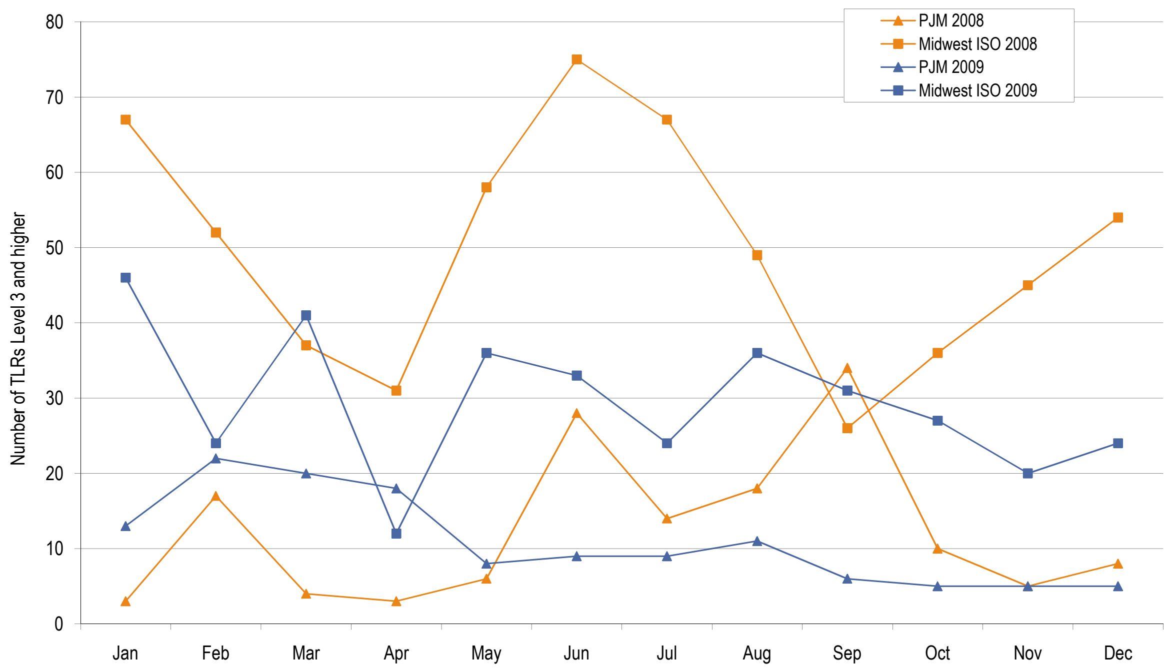


Figure 4-21 Number of different PJM flowgates that experienced TLRs: Calendar years 2008 and 2009

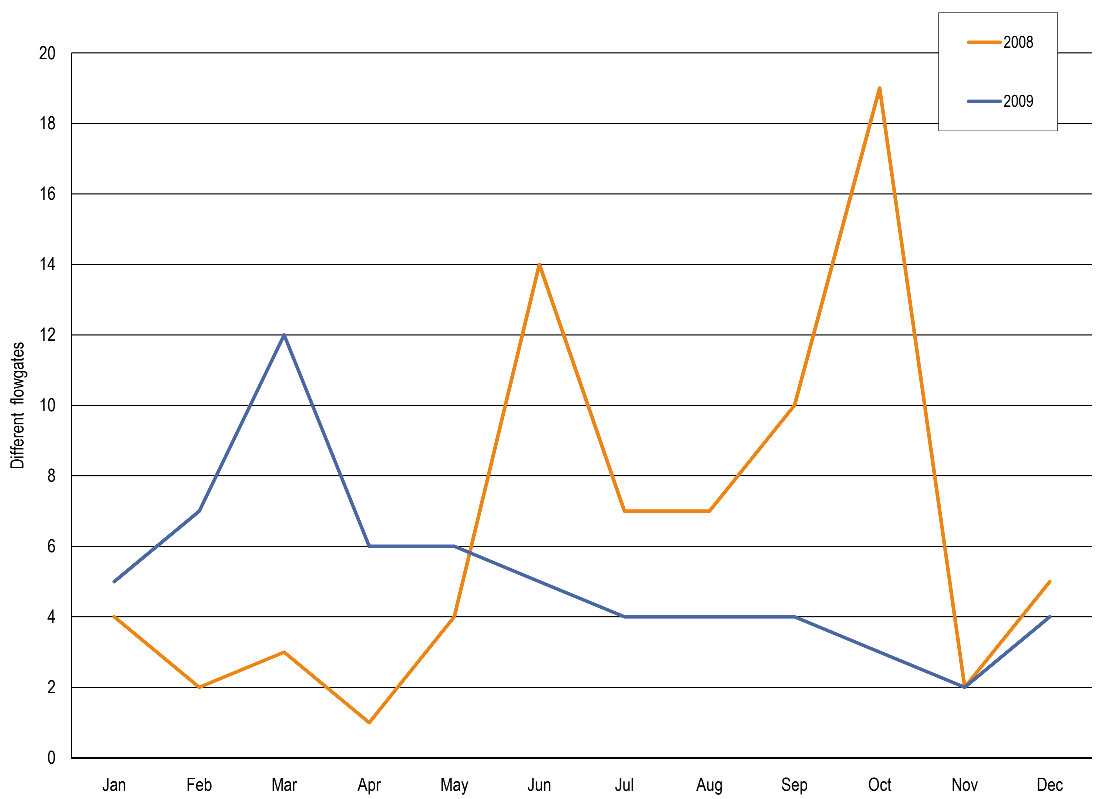


Figure 4-22 Number of PJM TLRs and curtailed volume: Calendar year 2009

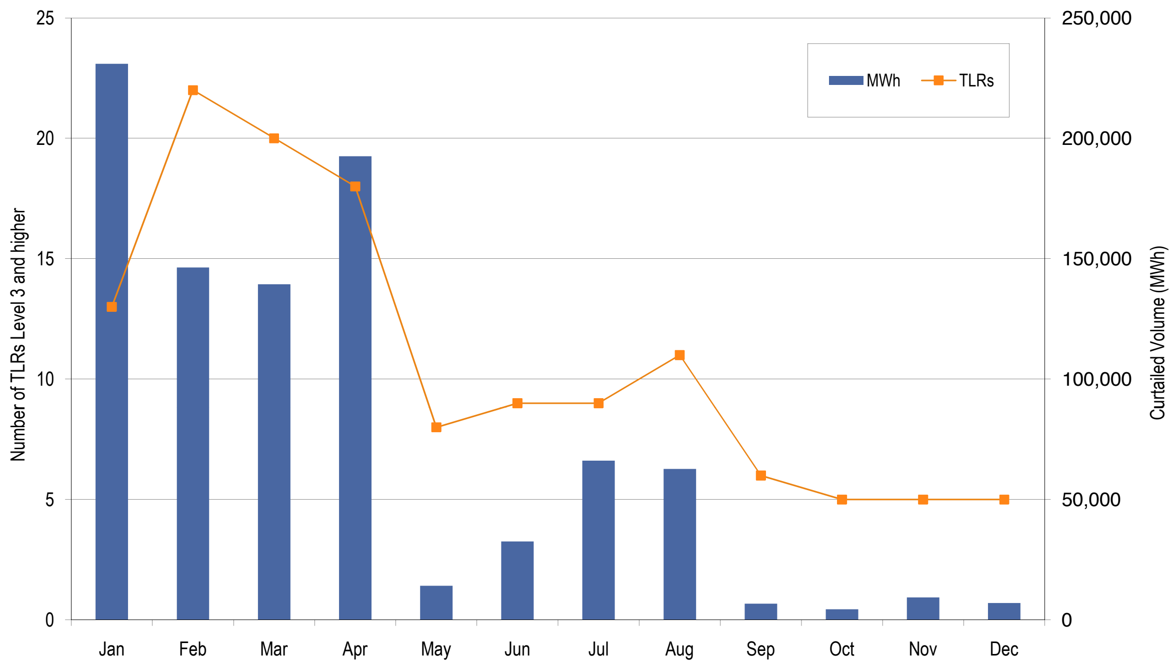


Table 4-13 shows the number of TLRs by TLR level for each reliability coordinator in the Eastern Interconnection. The TLR levels are defined in Appendix D "Interchange Transactions" of this document. During 2009, PJM issued 129 transmission loading relief procedures (TLRs). Of the 129 TLRs issued, the highest levels reached were TLR 3a in 61 instances and TLR 3b in the remaining 68 events (2008 totals were 55 TLR 3a, 92 TLR 3b, 2 TLR 4 and 1 TLR 5b).

Table 4-13 Number of TLRs by TLR level by reliability coordinator: Calendar Year 2009

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097

Up-To Congestion

The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Market. This product was offered as a tool for market participants to use to limit or hedge their congestion exposure on scheduled transactions in the Real-Time Market.

In submitting an up-to congestion transaction, the market participant is submitting a transaction equivalent to a matched set of incremental offers (INC) and decrement bids (DEC) that will be evaluated together and approved or denied as a single transaction, subject to a limit on the cleared price difference. For import up-to congestion transactions, the import pricing point specified looks like a DEC bid and the sink specified on the OASIS reservation looks like an INC offer. For export transactions, the specified source on the OASIS reservation looks like a DEC bid, and the export pricing point looks like an INC offer. Similarly, for wheel through up-to congestion transactions, the import pricing point chosen looks like a DEC bid, and the export pricing point specified looks like an INC offer.

While submitting an up-to congestion bid is similar to entering a matched pair of INC offers and DEC bids, there are a number of advantages to using the up-to congestion product rather than using sets of INC and DEC bids. For example, an up-to congestion transaction is approved or denied as a single transaction, will only clear the Day-Ahead Market if the maximum congestion bid criteria is met, and is not subject to day-ahead or balancing operating reserve charges.

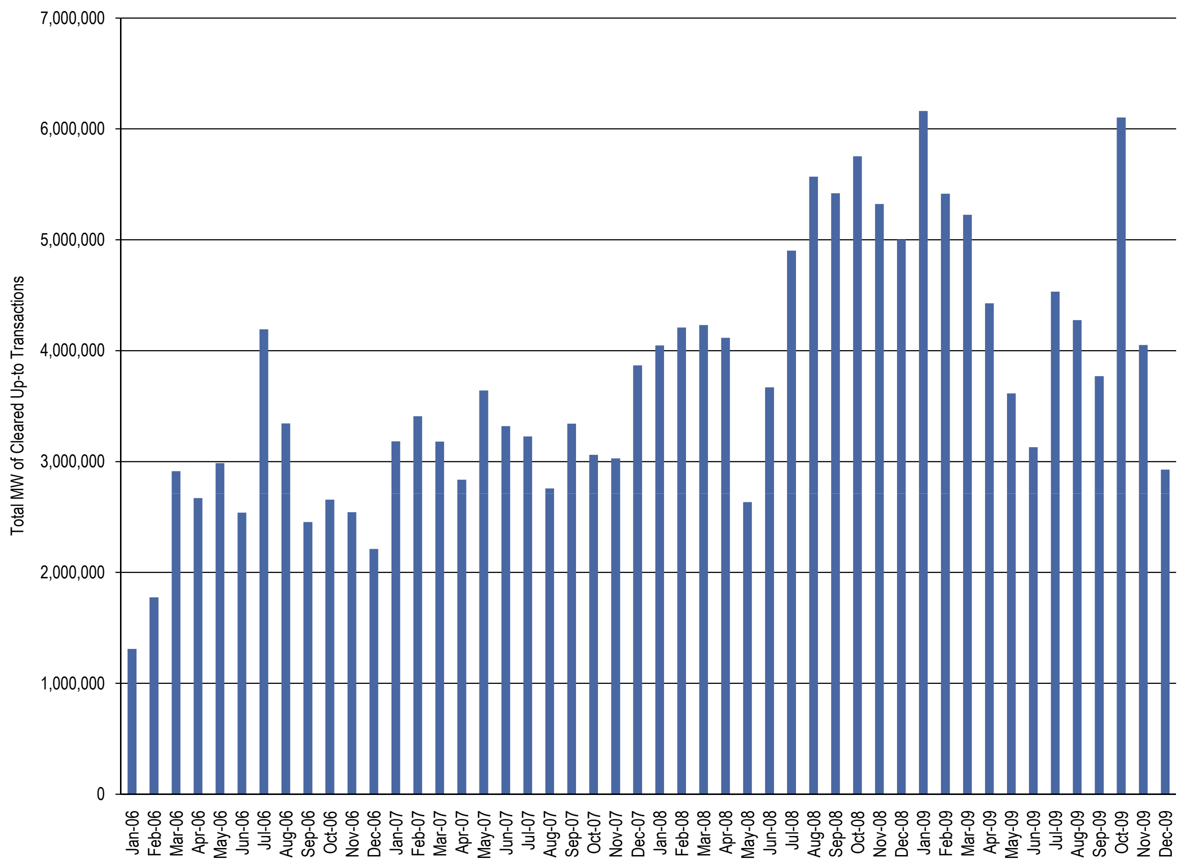
In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity.

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.[55] On February 21, 2008, the PJM Markets and Reliability Committee (MRC) approved PJM's proposed resolution to the request for implementation on March 1, 2008.[56] The proposal allowed for a modification to the offer cap from $25 to ± $50, including an explicit allowance for negative offers. PJM also eliminated a relatively small number of available sources and sinks in an effort to partially address the mismatch between the Day-Ahead and Real-Time Market scheduling. In the period following the March 1, 2008 modifications to the up-to congestion bids, through December 31, 2009, the monthly average of up-to congestion bidding increased from 3,027.1 GWh to 4,556.8 GWh. (See Figure 4-23.)

55 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221/20080221-item-03-up-to-congestion-transactions.ashx> (39 KB).

56 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221/20080221-minutes.ashx> (61KB).

Figure 4-23 Monthly up-to congestion bids in MWh: January 2006 through December 2009



The up-to congestion transactions in 2009 were comprised of 45.6 percent imports, 51.7 percent exports and 2.7 percent wheeling transactions. (See Table 4-14.) Only 0.2 percent of the up-to congestion transactions had matching Real-Time Market transactions. Of the up-to congestion transactions with matching Real-Time Market transactions, 26.5 percent were imports, 58.5 percent were exports and 15.0 percent were wheel through transactions.

Table 4-14 Up-to congestion MW by Import, Export and Wheels: Calendar years 2006 through 2009

	Import MW	Export MW	Wheeling MW	Total MW	Percent Imports	Percent Exports	Percent Wheels
2006	10,730,659	20,398,833	468,648	31,598,141	34.0%	64.6%	1.5%
2007	13,950,514	24,080,803	817,237	38,848,554	35.9%	62.0%	2.1%
2008	20,889,972	32,351,960	1,632,874	54,874,806	38.1%	59.0%	3.0%
2009	24,455,358	27,722,740	1,453,553	53,631,651	45.6%	51.7%	2.7%
Total	70,026,504	104,554,336	4,372,311	178,953,151	39.1%	58.4%	2.4%

Market participants have the opportunity to match the source and sink between the Day-Ahead and Real-Time Markets, but they have not done so. An analysis of the up-to congestion data shows that submitted Real-Time Market transactions match the submitted Day-Ahead Market up-to congestion bid only 0.2 percent of the time. For 99.8 percent of the time, submitted Real-Time

Market transactions do not match the submitted Day-Ahead Market up-to congestion bids being made by participants.

When the up-to congestion product was used as intended, with matching Real-Time Market transactions, 57.0 percent of the total cleared transaction MW were profitable in 2009. The net profit on all these transactions was approximately $100,000. When up-to congestion transactions did not have a matching Real-Time Market transaction, 61.7 percent of the total cleared transaction MW were profitable. The net loss on all these transactions was approximately $31.5 million.

Figure 4-24 and Figure 4-25 show the monthly positive, negative and net gains for matching and non-matching up-to congestion transactions. Figure 4-24 shows the matching transactions on a different scale than Figure 4-25. There is such a small number of matching transactions that the results would not be visible on the scale of Figure 4-25.

Figure 4-24 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Market transaction: Calendar year 2009

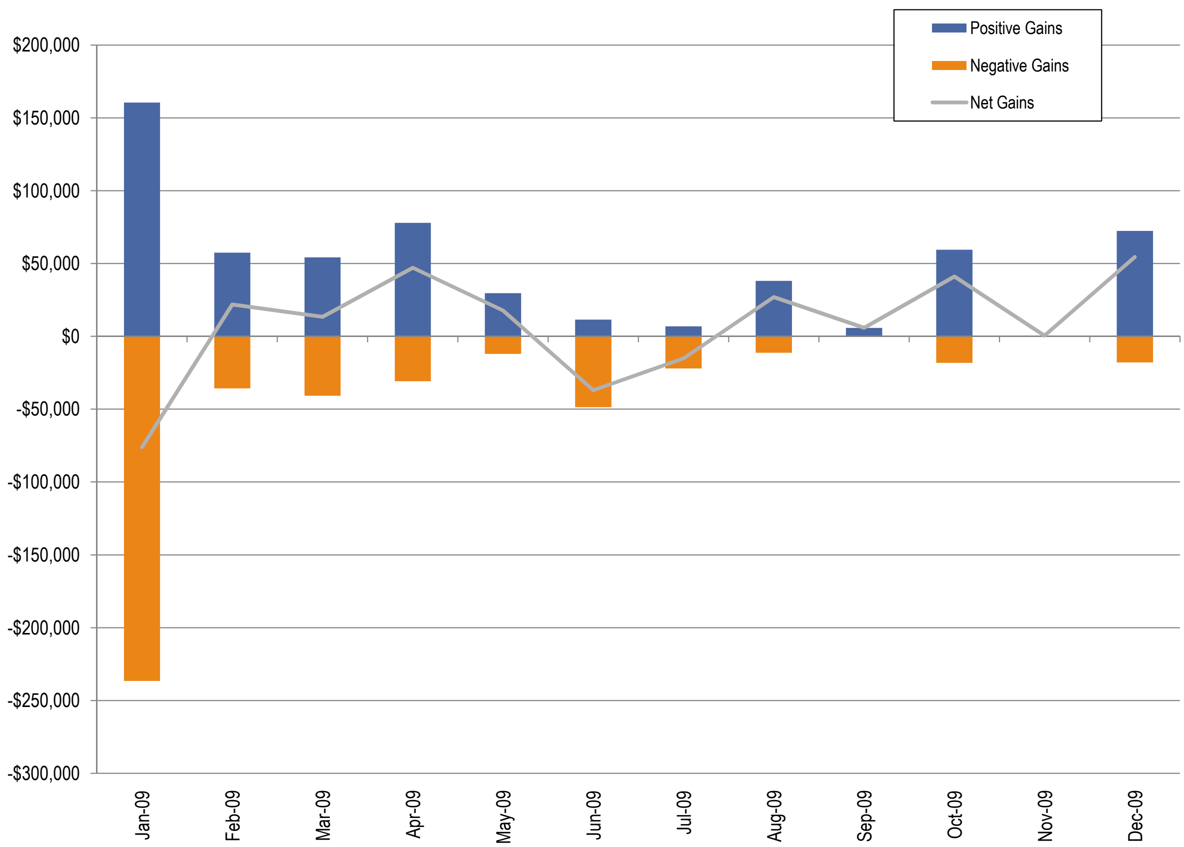
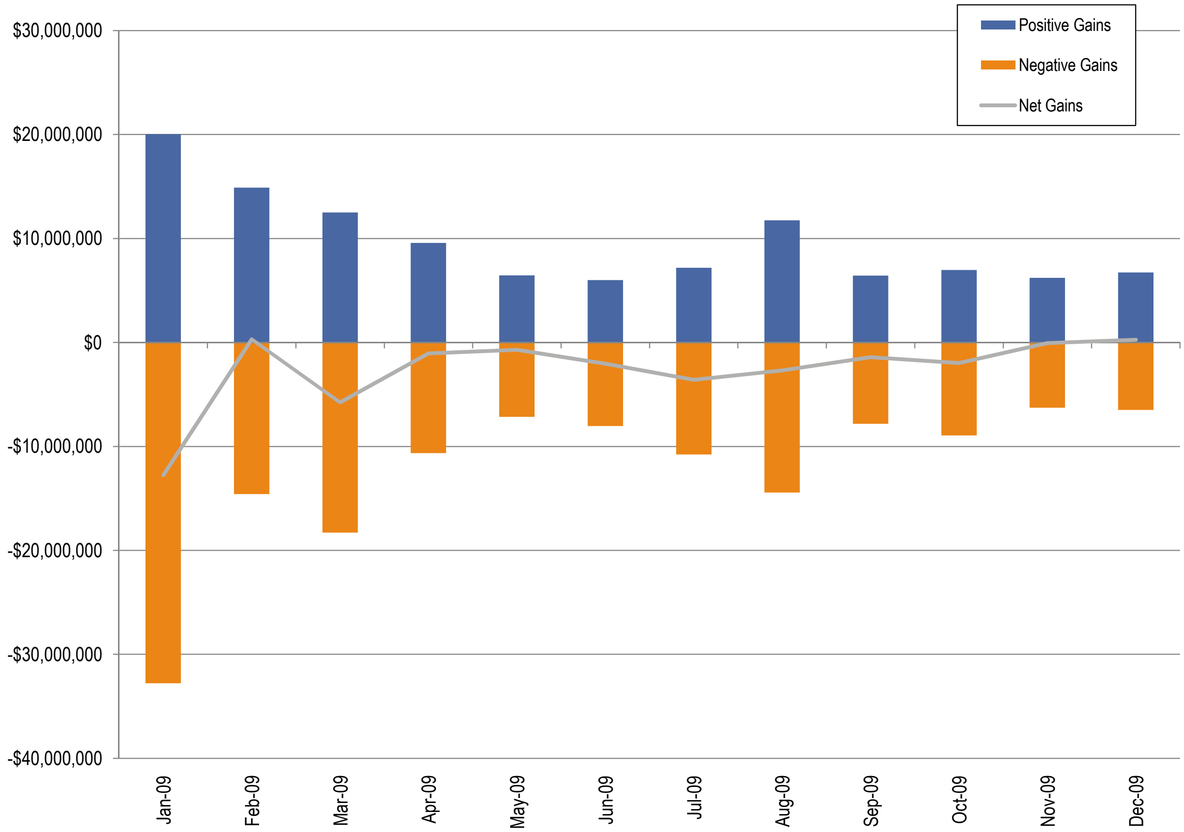


Figure 4-25 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Market transaction: Calendar year 2009



The consistency and volume of the mismatch between day-ahead and real-time sources and sinks in the submitted transactions indicates that this product is not being used as it was intended. The fact that cleared up-to congestion bids that do not have a matching real-time transaction lost approximately $31.5 million in 2009, and that these transactions are repeatedly being scheduled by the same participants is cause for concern. Of all market participants that utilize up-to congestion transactions, the top five participants accounted for 48 percent of all transactions and the top ten participants accounted for 74 percent of all transactions. The top five participants that experience losses accounted for 60 percent of all the losses, and the top ten participants accounted for 77 percent of all the losses on those bids.

The MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges.

The MMU also recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding and for all import and export transactions in the Day-Ahead and the Real-Time Markets.

The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

Interface Pricing Agreements with Individual Companies

PJM consolidated the southeast and southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[57] Table 4-15 shows the historical differences in LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation. The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, which has arisen at other interface pricing points, is that the multiple pricing points may create the ability to engage in false arbitrage. False arbitrage occurs when participants schedule transactions in response to interface price differences but the actual power flows associated with the transaction serve to drive prices further apart rather than relieving the underlying congestion. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

Table 4-15 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through December 2009

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2006	$42.55	$37.89	$38.36	$42.02	$4.20	($0.47)	$0.53	($4.13)
2007	$54.35	$45.48	$49.09	$48.48	$5.26	($3.61)	$5.87	($3.01)
2008	$62.97	$51.43	$55.47	$55.44	$7.50	($4.05)	$7.53	($4.01)
2009	$35.97	$31.94	$33.37	$33.37	$2.61	($1.42)	$2.61	($1.42)

PJM subsequently entered into confidential bilateral locational interface pricing agreements with three companies affected by the revised interface pricing point that provided more advantageous pricing to these companies than the applicable interface pricing rules. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[58] Progress Energy Carolinas, February 13, 2007;[59] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[60] Each of these agreements established a locational price for power purchases and sales between PJM and the individual company that applies under specified conditions. For example, when the company desires to sell into PJM (a PJM import), the rules required that the company cannot have simultaneous scheduled imports from other areas. Similarly, when a company wants to purchase from PJM (a PJM export), the rules require that the company cannot simultaneously have scheduled exports to other areas.

57 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (66 KB).

58 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/duke-pricing-agreement.ashx> (171 KB).

59 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pec-pricing-agreement.ashx> (210 KB).

60 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/electricities-pricing-agreement.ashx> (279 KB).

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 available for interface pricing between PJM and neighboring balancing authorities (BA).[61] These pricing point options include the existing SouthIMP/SouthEXP prices, the "Hi/Low" method and the "Marginal Cost Proxy Method."

The default pricing point for transactions between PJM and balancing authorities to the south are the SouthIMP and SouthEXP pricing points. While the SouthIMP and SouthEXP pricing points reflect the physical flows into and out of PJM from the ultimate source or sink, the interface encompasses a large geographic area, and individual neighboring BAs may benefit from providing additional data to take advantage of a more granular pricing mechanism.

Under the "Hi/Low" option, PJM uses the highest generator bus LMP for exports from PJM and the lowest generator bus LMP for imports into PJM to set the interface price. In addition, unit level telemetry can be provided that shows real-time unit status. When a generator is not running, the "high/low" method eliminates the LMP at that bus from the determination of the import or export price. To utilize the "high/low" option, PJM must be able to verify the source for import transactions and the sink for export transactions.

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 external supplier's marginal generator. The marginal generator is determined on the basis of 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 of any such units.

The proposed tariff revisions were filed with FERC on December 2, 2008[62], and approved on May 1, 2009.[63] 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

61 The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model" (August 2008) (Accessed January 20, 2010) <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf> (381 KB).

62 PJM Interconnection, L.L.C., Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008).

63 PJM Interconnection, L.L.C., Letter Order, Docket No. ER09-369-000 (May 1, 2009).

continue the "marginal cost proxy" pricing beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[64] As of December 31, 2009, Duke Energy Carolinas and Progress Energy Carolinas were in the process of negotiating a congestion management agreement with PJM.

In July 2009, Duke Energy Carolinas submitted the required data, and PJM had completed the required software modifications to support the "marginal cost proxy method." As of December 31, 2009 neither Progress Energy Carolinas nor the North Carolina Municipal Power Agency has elected to supply the additional data necessary to take advantage of the "high/low" or the "marginal cost proxy method" for interface pricing. Table 4-16 through Table 4-19 show the real-time and day-ahead prices for imports and exports applicable for the interface pricing under the various agreements (January data represents the pricing based on the original agreements, during the period from February 1 through May 3, 2009, the interface pricing was based on the SouthIMP and SouthEXP LMPs as there were no agreements in place, and the data shown for May 3, 2009 through the remainder of the year represents pricing based on the revised agreements).

In September 2009, Progress Energy Carolinas provided an update to the PJM Market Implementation Committee (MIC) on the proposed congestion management agreement.[65] The proposal included three parts: enhanced available transmission capability (ATC) coordination; monitoring of real-time parallel flow impacts; and managing real-time congestion.

On February 2, 2010, PJM filed a revised JOA to include the provisions of the proposed congestion management agreement. On February 23, the MMU provided comments on the filing.[66]

The MMU supports congestion management agreements but recommends that such agreements be implemented on a regional basis rather than between RTOs and individual external utility companies. In addition, there are a number of issues in the PJM/PEC agreement that need to be addressed. Most fundamentally, any congestion management agreement must ensure that the interface price established reflects the economic fundamentals of an LMP market.

Table 4-16 shows the real-time LMP calculated per the bilateral agreements and, for comparison, the SouthIMP and SouthEXP LMP for January 2009 (the time period when the original agreements were in place). The difference between the LMP under the agreements and PJM's SouthIMP/SouthEXP LMP ranged from $3.29 with Duke to $4.93 with PEC.[67] Table 4-17 shows the real-time LMP calculated per the revised agreements made effective on May 3, 2009 through the remainder of 2009. The difference between the LMP under this agreement and PJM's SouthIMP/SouthEXP LMP ranged from $1.06 with Duke to $1.36 with PEC.

Table 4-16 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January 2009

	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

64 127 FERC ¶61,101.

65 See "PJM-Progress Draft Congestion Management Agreement" (September 10, 2009) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mic/20090910/20090910-item-08-pjm-progress-draft-congestion-management-agreement.ashx> (69 KB).

66 (See PJM. "20100202-er10-xxx-000-joa.pdf"(February 2, 2010) (Accessed February 28, 2010) <http://www.pjm.com/~/media/documents/ferc/2010-filings/20100202-er10-xxx-000-joa.ashx> (2,277 KB)). (See Monitoring Analytics. "Corrected Motion to intervene and comments of the independent market monitor for PJM.pdf" (February 23, 2010) (Accessed February 28, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Motion_to_Intervene_and_Comments_ER10-713-000_20100225.pdf> (225 KB)).

67 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

Table 4-17 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through December 2009

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.87	$32.20	$30.82	$30.81	$1.06	$1.39
PEC	$32.18	$33.50	$30.82	$30.81	$1.36	$2.69
NCMPA	$32.01	$32.08	$30.82	$30.81	$1.19	$1.27

Figure 4-26 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2009

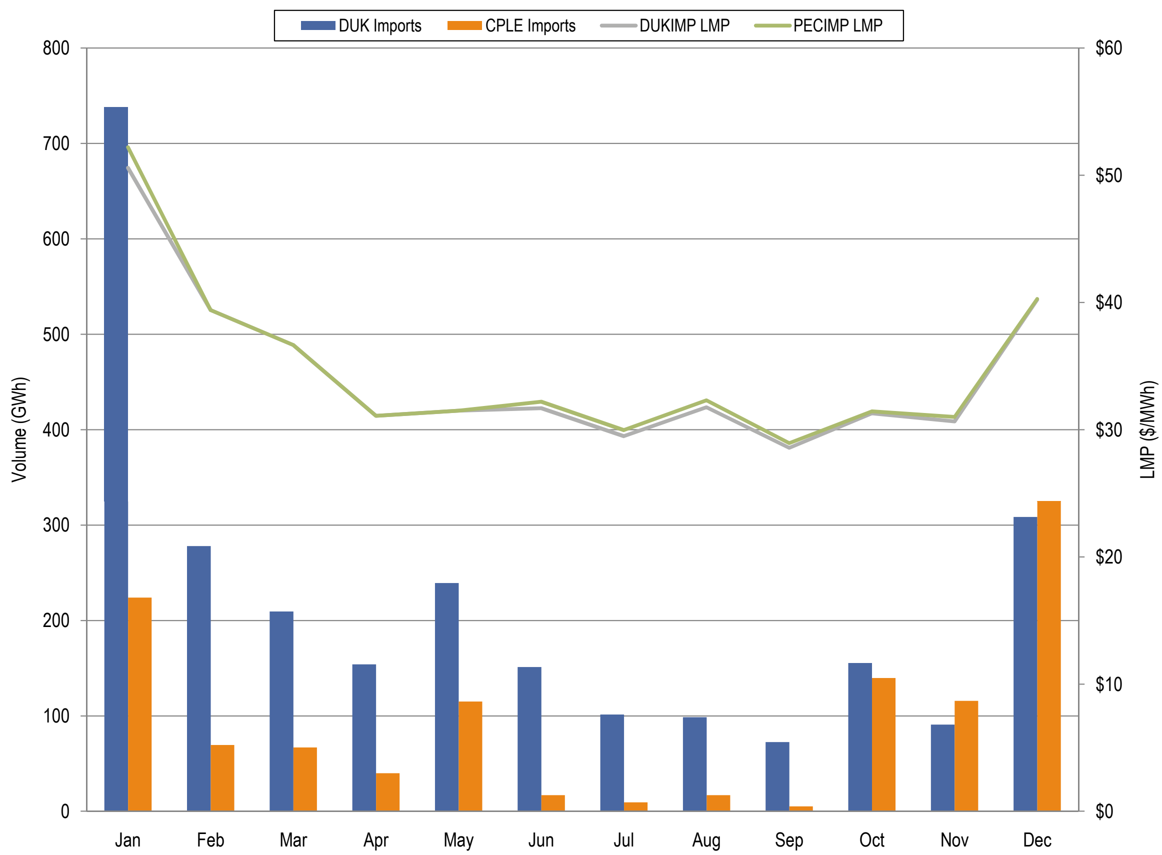


Figure 4-27 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2009

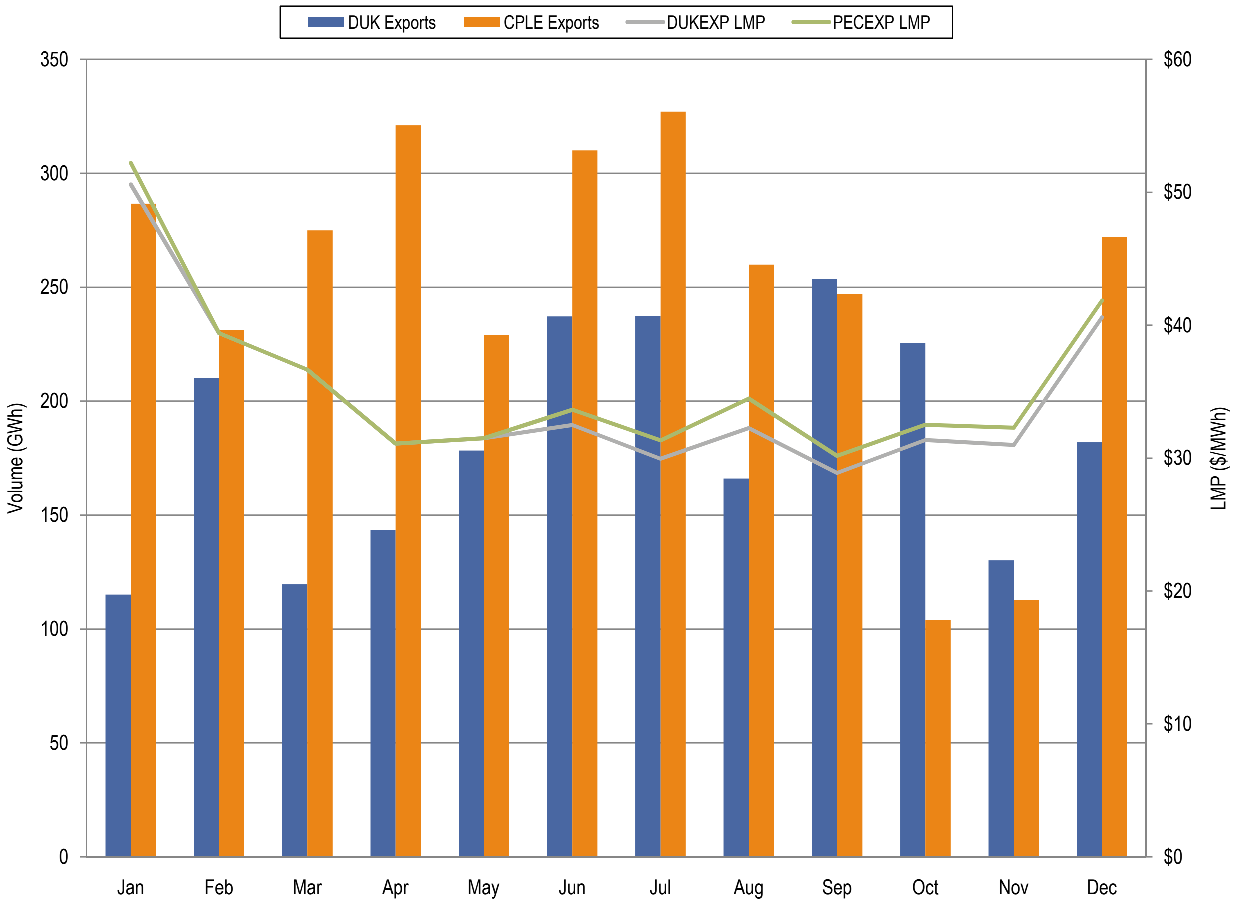


Table 4-18 shows the day-ahead LMP calculated per the bilateral agreements and, for comparison, the SouthIMP and SouthEXP LMP for January 2009 (the time period when the original agreements were in place). The prices available to Duke, CPLE and NCMPA under the agreement were higher than the SouthIMP and SouthEXP Interface prices. The difference between the LMP under the agreements and PJM's SouthIMP/SouthEXP LMP ranged from $3.42 with Duke to $5.82 with PEC. Table 4-19 shows the day-ahead LMP calculated per the revised agreements made effective on May 3, 2009 through the remainder of 2009. The prices available to Duke, CPLE and NCMPA under the revised agreement remained higher than the SouthIMP and SouthEXP Interface prices but the differences were not as large. The difference between the LMP under this agreement and PJM's SouthIMP/SouthEXP LMP ranged from $0.86 with Duke to $1.35 with PEC.

Table 4-18 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January 2009

	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 4-19 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through September 2009

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.91	$32.51	$31.04	$31.04	$0.86	$1.47
PEC	$32.39	$33.86	$31.04	$31.04	$1.35	$2.81
NCMPA	$32.18	$32.25	$31.04	$31.04	$1.13	$1.20

Figure 4-28 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2009

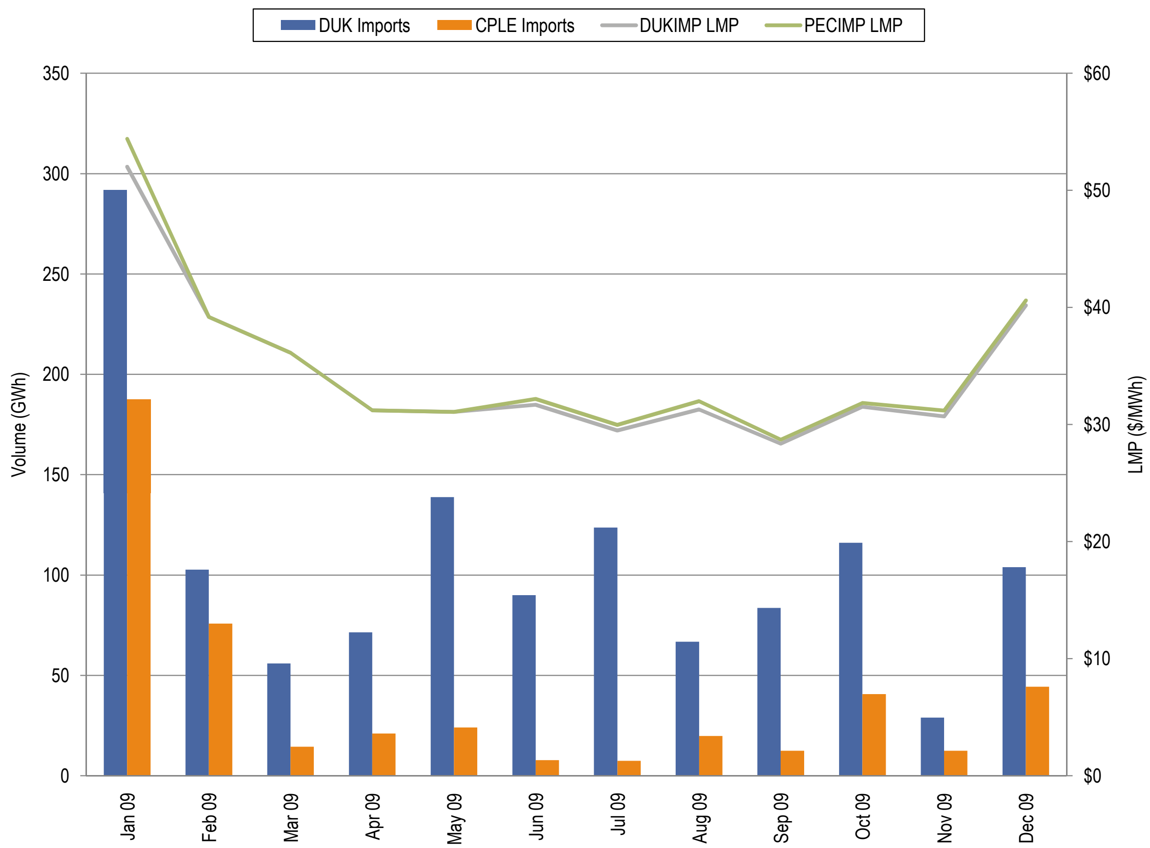
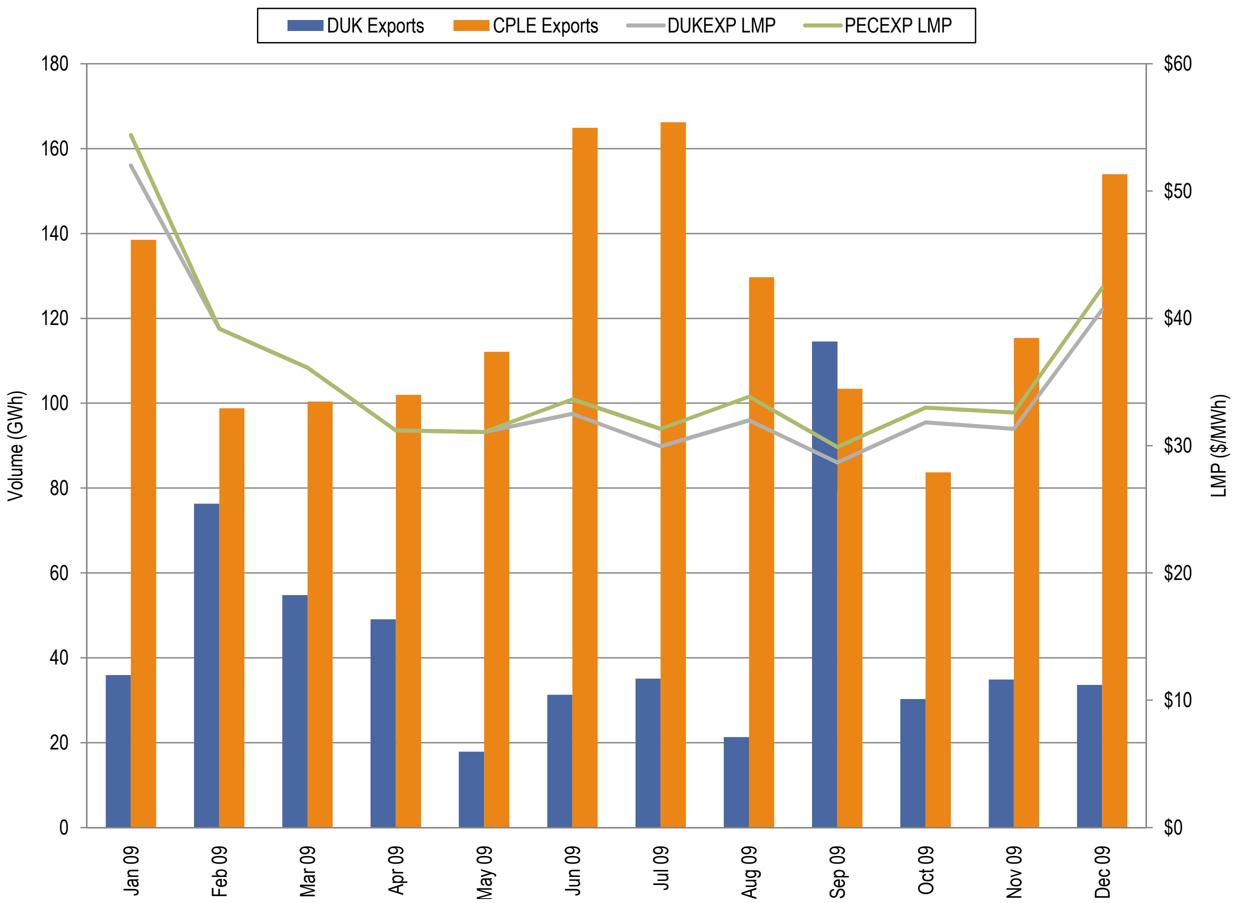


Figure 4-29 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2009



Spot Import

Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. WPC provided market participants the ability to offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, effectively limited interchange.

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 JOA with the 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.[68] 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

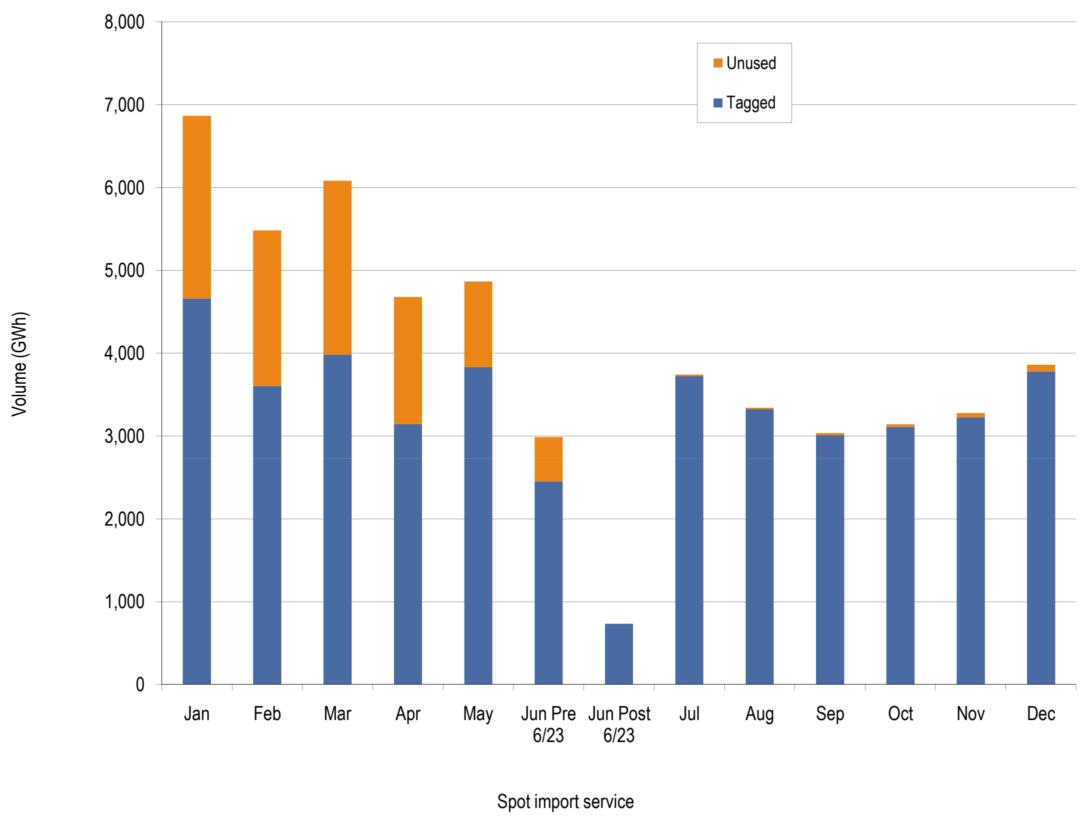
68 See "WPC White Paper" (April 20, 2007) (Accessed January 15, 2010) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[69] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within 2 hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

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 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 two hours when queued the day prior. On June 23, 2009 PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage has been over 99 percent, compared to 70 percent prior to the modification. (See Figure 4-30.) The MMU will continue to monitor participant use of spot import service.

Figure 4-30 Spot import service utilization: Calendar year 2009



69 See "Regional Transmission and Energy Scheduling Practices" (May 1, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/etools/oasis/20090131-regional-practices-redline.ashx> (450 KB).

Willing to Pay Congestion and Not Willing to Pay Congestion

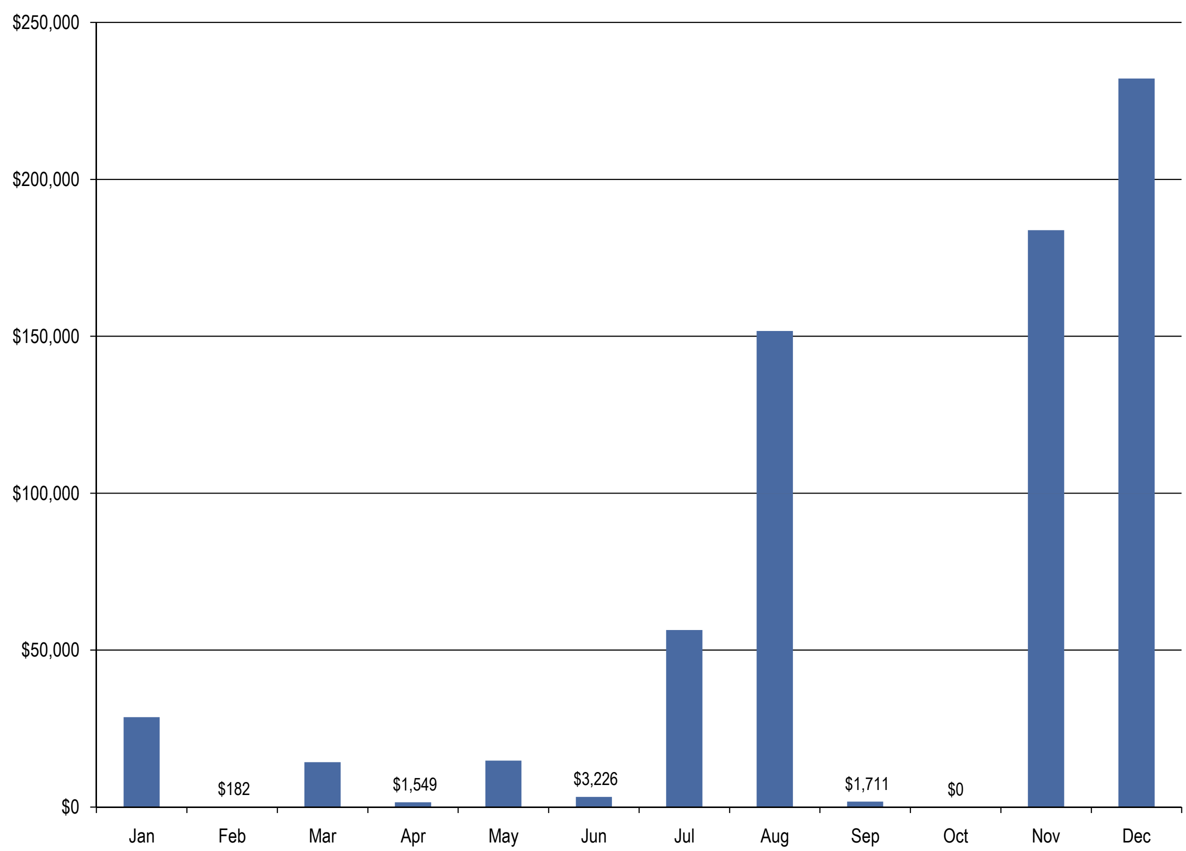
When reserving non-firm transmission, the market participant has the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow.

If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction.

Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. The method that PJM uses to curtail not willing to pay congestion requires the transaction to be loaded. While loaded, if congestion occurs for a not willing to pay congestion transaction, a message is sent to the PJM operators requesting the transaction be curtailed at the next 15 minute interval.

Figure 4-31 shows the monthly uncollected congestion charges for 2009. The total uncollected congestion charges for 2009 were $688,547 which was a reduction of 92 percent from the 2008 total of $8,662,695. The MMU recommends modifying the evaluation criteria via a change to PJM's market software, to ensure that a not willing to pay congestion transaction is not permitted to flow in the presence of congestion.

Figure 4-31 Monthly uncollected congestion charges: Calendar year 2009



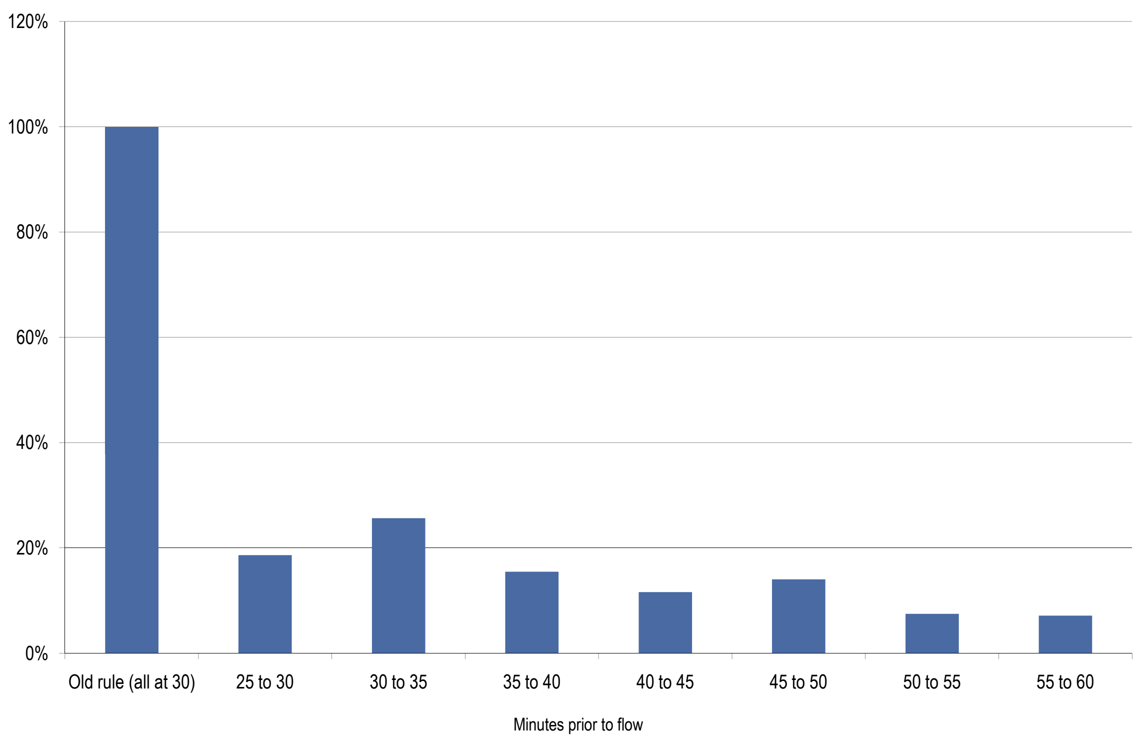
Ramp Availability

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 to 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 default limit is ± 1,000 MW within a 15 minute interval. 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.

Figure 4-32 shows the ongoing results of the ramp rule change that became effective on August 7, 2006. Under the new rule, unused ramp reservations expire at the conclusion of a defined time interval that starts when a reservation is approved. The goal was to prevent large swings in ramp 30 minutes prior to flow, and to spread automatic ramp reservation expirations over a longer period to permit other participants to use them. The actual distribution pattern of expirations since the rule change is compared to when reservations would have expired under the old rule in Figure 4-32. Under the old rule, all unused reservations had expired at the same time, 30 minutes prior to flow or just 10 minutes prior to the deadline for scheduling a transaction (20 minutes prior to flow).

Figure 4-32 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through December 2009



The artificial creation of ramp room is an ongoing issue. 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, which permits the participant to obtain an import reservation. The import transaction flows and the export reservation expires after its time limit. In 2007, PJM modified its business rules to permit PJM to curtail such a participant's transaction(s) prior to using the normal, last-in-first-out method of ordering curtailments, if PJM determines that a participant has scheduled an offsetting reservation that is unused.[70] Although the rule has been added, the mechanism for automatically performing this task has not yet been developed. System operators may apply this rule manually.

Large swings in PJM's ramp availability have continued to be regularly observed at the NYISO Interface. The NYISO rules for its hourly market require transaction bids to be placed at least 75 minutes prior to flow. For each potential import or export transaction that is bid into the NYISO market, a PJM ramp reservation is required. During the time between the bid submission to the NYISO and the time the NYISO market results are posted, all ramp reservations associated with all the bids are in PJM's system, often leaving no ramp available, awaiting the outcome of the NYISO market clearing. When the NYISO market results are posted, the ramp reservations for any unsuccessful bids are returned to the PJM system. The result is a large swing in ramp observed at approximately 20 minutes after the hour. The difference between transaction rules in the NYISO and PJM create incentives to obtain ramp that will not be needed. There is also the potential for gaming by submitting out-of-market bids and offers for import or export transactions to the NYISO, thus limiting ramp availability to competitors. Additionally, market participants can extend their NYISO market bids to cover multiple hours to acquire ramp by submitting out-of-merit bids and offers. For example, if ramp is not available at the end time of the desired hour, the market participant can submit a NYISO schedule to cover two hours, thus having no effect at the time when ramp is not available. When the NYISO evaluates the second hour, it will not pass their market (as it is out-of-merit) and they will deny the transaction. PJM will have no choice but to remove the transaction from the second hour, thus causing a ramp violation at the end of the first hour where ramp was initially not available.

The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit was set based on the generally available ramping capability of generators on the PJM system. PJM must limit the amount of imports or exports at each 15 minute interval to account for the physical characteristics of the generation to meet the imports and exports. In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intra-hour LMP changes. As a result, a new business rule was proposed, and approved, to require all transactions to be at least 45 minutes in duration.[71] On May 1, 2008, the Enhanced Energy Scheduler (EES) system was modified to require that transactions be 45 minutes in duration. Since that modification, market participants have scheduled 1 MW for the first 30 minutes, and increased to a larger MW value for the last 15 minutes, thus continuing to create significant swings in imports and exports. The MMU recommends that the EES application be modified further to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible.

70 PJM. "Manual 41: Managing Interchange," Revision 03 (November 24, 2008), p. 9.

71 PJM. "Manual 41: Managing Interchange," Revision 03 (November 24, 2008), p. 5.