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.

Highlights and New Analysis

- Real-time net exports increased from -1,407 GWh in 2009 to -9,661 GWh in 2010, and day-ahead net exports decreased from -9,032.5 GWh in 2009 to -6,470.0 GWh in 2010.

- In 2010, the direction of power flows at the borders between PJM and the Midwest ISO and between PJM and the NYISO was not consistent with real-time energy market price differences for a majority of hours in 2010, 58 percent between PJM and the Midwest ISO and 51 percent between PJM and NYISO.

- System loop flows increased from 2.2 percent for the calendar year 2009 to 5.2 percent for the calendar year 2010.

- PJM initiated fewer TLRs in 2010 (110 TLRs) than in 2009 (129 TLRs).

- The Midwest ISO and PJM filed a settlement agreement resolving all complaints regarding the management of the Joint Operating Agreement.

- The Commission supported an expedited timeline in the Broader Regional Market docket, and ordered interface pricing modifications and the development of a market-to-market congestion management protocol by the second quarter of 2011.

- The Commission conditionally accepted a Congestion Management Protocol between PJM and Progress Energy Carolinas.

- Changes to the marginal loss surplus allocation created opportunities for market participants to submit uneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus. Customers entering uneconomic bids profited by $9.6 million after the cost of transmission as a result of the change in the allocation methodology.

- The daily volume of up-to congestion bids increased from approximately 600 bids per day, prior to the September 17, 2010 modification to the up-to congestion product that eliminated the requirement to procure transmission, to approximately 950 bids per day.

- Total uncollected congestion charges for 2010 were $3.3 million, a 379 percent increase from the 2009 total uncollected congestion charges of $688,547.

- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were approximately $24 million in 2010, an increase from the 2009 total of approximately $91,000.

Summary Recommendations

- The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent. The MMU recommends changing the not willing to pay congestion product to eliminate uncollected congestions charges, eliminating internal source and sink bus designations for external energy transactions, eliminating or modifying the dispatchable transactions and up to congestion transactions products to reduce or eliminate gaming opportunities associated with the products.

- 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 recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2010, PJM was a net exporter of energy in the Real-Time Energy Market in all months. In the Real-Time Energy Market, monthly net interchange averaged -805 GWh.[1] Gross monthly import volumes averaged 3,496 GWh while gross monthly exports averaged 4,301 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2010, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months except August, November and December. In the Day-Ahead Energy Market, monthly net interchange averaged -539 GWh. Gross monthly import volumes averaged 7,342 GWh while gross monthly exports averaged 7,881 GWh.

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** In 2010, gross imports in the Day-Ahead Energy Market were 210 percent of the Real-Time Energy Market's gross imports (111 percent for the calendar year 2009), gross exports in the Day-Ahead Energy Market were 183 percent of the Real-Time Energy Market's gross exports (127 percent for the calendar year 2009) and net interchange in the Day-Ahead Energy Market was 67 percent of net interchange in the Real-Time Energy Market (-9,661GWh in the Real-Time Energy Market and -6,470 GWh in the Day-Ahead Energy Market).

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market in 2010, there were net exports at 16 of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 70 percent of the total net exports:

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.

PJM/New York Independent System Operator, Inc. (NYIS) with 30 percent, PJM/Neptune (NEPT) with 20 percent and PJM/MidAmerican Energy Company (MEC) with 20 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 Energy Market. Four PJM interfaces had net imports, with two importing interfaces accounting for 90 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 78 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 12 percent.[2]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, there were net exports at 12 of PJM's 21 interfaces. The top four net exporting interfaces accounted for 92 percent of the total net exports: PJM/NYIS with 33 percent, PJM/western Alliant Energy Corporation (ALTW) with 25 percent, PJM/MidAmerican Energy Company (MEC) with 18 percent and PJM/NEPT with 16 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND). Combined, these interfaces made up 50 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interfaces had net imports in the Day-Ahead Energy Market, with two interfaces accounting for 78 percent of the total net imports: PJM/OVEC with 47 percent and PJM/Michigan Electric Coordinated System (MECS) with 31 percent.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** In 2010, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2010, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $33.33 while the Midwest ISO LMP at the border was $33.90, a difference of $0.57, while the average hourly flow in 2010 was -918 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 42 percent of hours of 2010. While the average hourly LMP difference at the PJM/MISO border was only $0.57, the average of the absolute value of the hourly difference was $11.64. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $51.5 million at the PJM/MISO Interface.

- **PJM and New York ISO Interface Prices.** In 2010, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In 2010, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was not consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the PJM/NYISO border was $47.64 while the NYISO LMP at the border was $44.69, a difference of $2.95, while the average hourly flow was -722 MW. (The negative sign means that the flow was an export from

2 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/western portion of Carolina Power & Light Company (CPLW)).

PJM to NYISO, which is not consistent with the fact that the average PJM price was higher than the average NYISO price.) The direction of flows was consistent with price differentials in only 49 percent of the hours. While the average hourly LMP difference at the PJM/NYISO border was only $2.95, the average of the absolute value of the hourly difference was $14.74. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $52.7 million at the PJM/NYIS Interface.

- **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 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. In 2010, the average price difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Neptune Interface was $51.40 while the NYISO LMP at the Neptune Bus was $58.08, a difference of $6.67, while the average hourly flow in 2010 was -544 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64 percent of the hours. While the average hourly LMP difference at the PJM/Neptune border was only $6.67, the average of the absolute value of the hourly difference was $23.30. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was approximately $43.4 million at the PJM/NEPT Interface.

- **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.[3] 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. In 2010, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Linden Interface was $50.10 while the NYISO LMP at the Linden Bus was $51.58, a difference of $1.48, while the average hourly flow was -139 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 61 percent of the hours. While the average hourly LMP difference at the PJM/Linden border was only $1.48, the average of the absolute value of the hourly difference was $18.13. During all hours where flows did not align with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was approximately $8.8 million at the PJM/LIND Interface.

3 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.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[4] On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It also formalized 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.

  The PJM/NYISO JOA does not include provisions for market based congestion management or other market to market activity, and, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued in 2010.

- **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 in 2010. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. The MMU believes that this approach should be the minimum industry standard. This conceptual achievement, however, has not been matched by adequate attention to the details of its administration, which have resulted in multiple FERC filings by the Midwest ISO and PJM.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[5] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management 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 2010.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[6] 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 2010. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[7] The MMU responded to the filing on February 23, 2010.[8]

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[9] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC SERC Reliability Corporation Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data.

4 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) (Accessed March 7, 2011) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (2,285 KB).

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

6 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) (Accessed March 7, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (2,983 KB).

7 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

8 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010)

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

Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

Other Agreements/Protocols with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** In 2010, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[10] This protocol allows Con Edison to elect up to the flow specified in each of two contracts through the PJM Day-Ahead Energy Market. A 600 MW contract is for firm service and a 400 MW contract has a priority higher than non-firm service, but lower than firm service. These elections obligate PSE&G to pay congestion 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.

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 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.

  In 2010, net scheduled interchange was -6,778 GWh and net actual interchange was -6,425 GWh for a difference of 353 GWh or 5.2 percent (2.2 percent for the calendar year 2009).

  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 2009, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-15,106 GWh in 2010 and -14,441 GWh for the calendar year 2009). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (4,015 GWh in 2010 and 3,840 GWh for the

10 111 FERC ¶ 61,228 (2005).

calendar year 2009). The net difference between scheduled flows and actual flows at the PJM/MECS Interface was exports while the net difference at the PJM/TVA Interface was imports.

- o **Loop Flows at PJM's Southern Interfaces.** The difference between scheduled and actual power flows at PJM's southern interfaces was significant in 2010. PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) are in the west. The largest differences in the west were at the TVA Interface. The net scheduled power flow at the TVA Interface was -703 GWh and the actual flow was 3,312 GWh, a difference of 4,015 GWh. PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK are in the east. The largest differences in the east were at the CPLE Interface. The net scheduled power flow at the CPLE Interface was -421 GWh and the actual flow was 8,350 GWh, a difference of 8,771 GWh.

- **PJM Transmission Loading Relief Procedures (TLRs).** In 2010, PJM issued 110 TLRs of level 3a or higher. Of the 110 TLRs issued, 65 events were TLR level 3a, and the remaining 45 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. The fact that PJM issued only 110 TLRs in 2010, compared to 129 in 2009, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with the Midwest ISO. PJM's operating rules allow PJM to reconfigure the transmission system prior to reaching system operating limits that would require the need for higher level TLRs.

- **Up-To Congestion.** In the period following the March 1, 2008, modifications to the up-to congestion bids (March 1, 2008, through December 31, 2010), the monthly average of up-to congestion bids increased from 3,027.1 GWh (for the period from January 1, 2006 through April 30, 2008) to 6,192.9 GWh. In June and July, there was a significant increase in the total up-to congestion bids. This increase in activity for up-to congestion transactions was the result of the allocation methodology for the marginal loss surplus.

- **Marginal Loss Surplus Allocation.** In an order on complaint, the Commission required PJM to correct an inconsistency in the tariff language defining the method for allocating the marginal loss surplus based on contributions to the fixed costs of the transmission system.[11] PJM's tariff modification resulted in an allocation of the marginal loss surplus based on usage of the system rather than based on the dollar contribution to the fixed costs of the transmission system. The inconsistency between the allocation principle defined by FERC and the actual allocation created an incentive for market participants to enter noneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** When reserving non-firm transmission, market participants have 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. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

11 See 131 FERC ¶ 61,024 (2010) (order denying rehearing and accepting compliance filing); 126 FERC ¶ 61,164 (2009) (Order on request for clarification).

The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service; and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces. PJM stakeholders approved the changes recommended by the MMU. These modifications are currently being evaluated by PJM to determine if tariff or operating agreement changes are necessary prior to implementation.

- **Elimination of Sources and Sinks.** The MMU has recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch.

- **Spot Import.** In 2009, PJM and the MMU jointly addressed a concern regarding the underutilization of spot import service. Because spot import service is available at no cost, and is limited by available transfer capabilities (ATC), market participants were able to reserve all of the available service with no economic risk. The market participants could then choose not to submit a transaction utilizing the service if they did not believe the transaction would be economic. By reserving the spot import service and not scheduling against it, they effectively withheld the service from other market participants who wished to utilize it. To address the issue, PJM implemented new timing requirements that retracted spot import reservations if they were associated with a NERC Tag within 30 minutes of making the reservation. Although this resulted in an increase in scheduling, some participants were still able to schedule but not use spot import service to flow energy. As a result, the MMU and PJM recommended that PJM revert to unlimited ATC for non-firm willing to pay congestion service. The PJM Stakeholders agreed with the recommendation, and requested that PJM determine what would be needed to implement the change.

- **Real-Time Dispatchable Transactions.** Dispatchable transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes has eliminated the value that dispatchable transactions once provided market participants. Dispatchable transactions now only serve as a potential mechanism for receiving operating reserve credits.

  The MMU recommends that dispatchable transactions be eliminated as an option for market participants. Alternatively, the MMU recommends that the evaluation of dispatchable transactions be modified from the manual process implemented today, and be included in the Generation Control Application (GCA) tool and modeled in same way as a unit offer with a one hour minimum run time. This would eliminate the potential for a dispatchable transaction to be loaded and continue to flow in subsequent hours when the transaction is not economic, thus accruing balancing operating reserve credits, and would treat these transactions the same way that dispatchable units are treated. This would enhance the efficiency of PJM dispatch of system resources.

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.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities for 2010, including evolving transaction patterns, economics and issues. In 2010, 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 70 percent of the total real-time net exports and two interfaces accounted for 90 percent of the real-time net import volume. Four interfaces accounted for 92 percent of the total day-ahead net exports and two interfaces accounted for 78 percent of the day-ahead net import volume.

In 2010, the direction of power flows at the borders between PJM and the Midwest ISO and between PJM and the NYISO was not consistent with real-time energy market price differences for a majority of hours, 58 percent between PJM and the Midwest ISO and 51 percent between PJM and NYISO. The MMU recommends that PJM work with both Midwest ISO and NYISO to improve the ways in which interface prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by reliance on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Interactions between PJM and other balancing authorities should be governed by the same market principles that govern transactions within PJM. That is not yet the case. The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

Detailed Recommendations

- The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent.

- The MMU recommends that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets.

- The MMU recommends that dispatchable transactions be eliminated as an option for market participants.

- The MMU recommends that the up-to congestion transaction product be eliminated. Alternatively, the MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges.

- The MMU recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding.

- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions).

- The MMU recommends that the Enhanced Energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible.

- 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 recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

    - The MMU recommends that PJM work with both Midwest ISO and NYISO to improve the ways in which interface prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. PJM is engaged in preliminary discussions with both Midwest ISO and NYISO on interface pricing.

    - The MMU recommends that the PJM and Midwest ISO JOA be modified to eliminate payments between RTOs when such payments would result from the failure of generating units to respond to appropriate pricing signals.

    - The MMU recommends that the grandfathered Southeast and Southwest Interface pricing agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing.

- 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.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months of 2010 (Figure 4-1, Figure 4-2 and Figure 4-3).[12,13] The total 2010 real-time net interchange of -9,661 GWh was greater than net interchange of -1,407 GWh in 2009. The peak month in 2010 for net exporting interchange was October, -1,335 GWh; in 2009 it had been June, -1,031 GWh. Monthly gross exports averaged 4,301 GWh and monthly gross imports averaged 3,496 GWh, for an average monthly net interchange of -805 GWh.

PJM was a net importer of energy in the Day-Ahead Energy Market in August, November and December of 2010, and a net exporter of energy in the remaining months. Total net interchange was -6,470 GWh. The peak month for net exporting interchange was April, -1,891 GWh. The peak month for net importing interchange was December, 1,603 GWh. Monthly gross exports averaged 7,881 GWh and monthly gross imports averaged 7,342 GWh, for an average monthly net interchange of -539 GWh.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Energy Markets. In 2010, gross imports in the Day-Ahead Energy Market were 210 percent of the Real-Time Energy Market's gross imports (111 percent for the calendar year 2009), gross exports in the Day-Ahead Energy Market were 183 percent of the Real-Time Energy Market's gross exports (127 percent for the calendar year 2009) and net interchange in the Day-Ahead Energy Market was 67 percent of net interchange in the Real-Time Energy Market (-9,661 GWh in the Real-Time Energy Market and -6,470 GWh in the Day-Ahead Energy Market).

12 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.

13 The interchange values shown in Figure 4-1,Figure 4-2 and Figure 4-3, and Table 4-1 through Table 4-6 do not include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in these figures and tables does not match the "Net Scheduled" values shown in Table 4-10.

Figure 4-1 PJM real-time scheduled imports and exports: Calendar year 2010

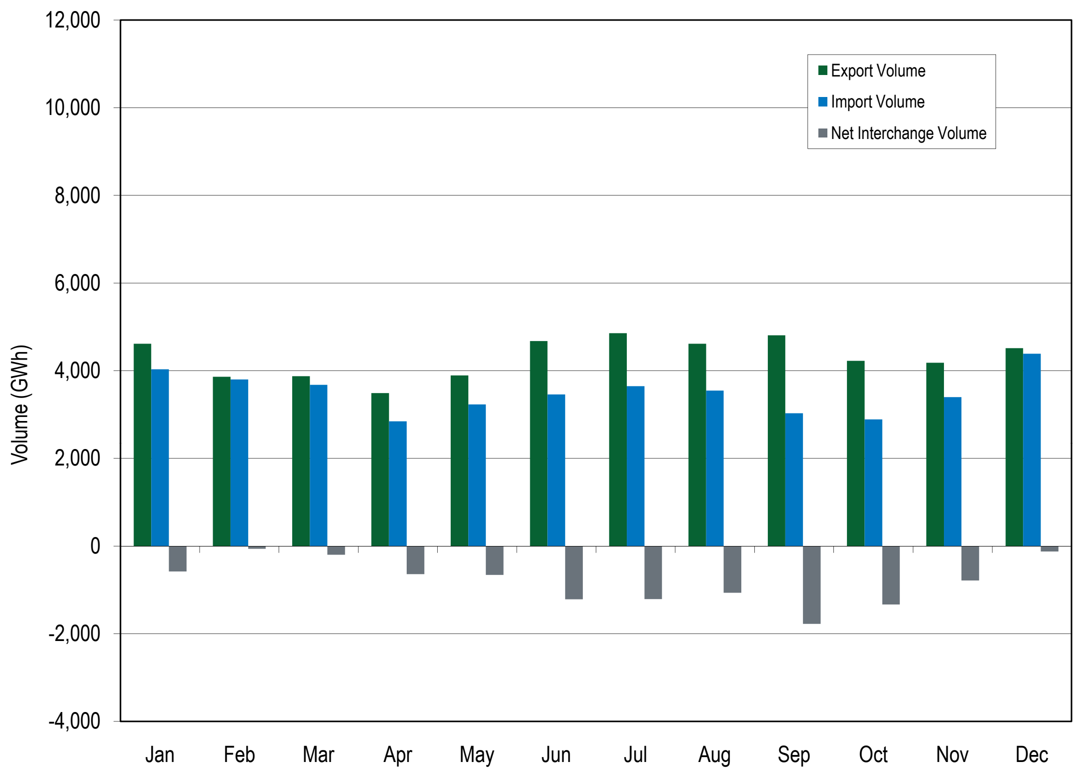


Figure 4-2 PJM day-ahead scheduled imports and exports: Calendar year 2010

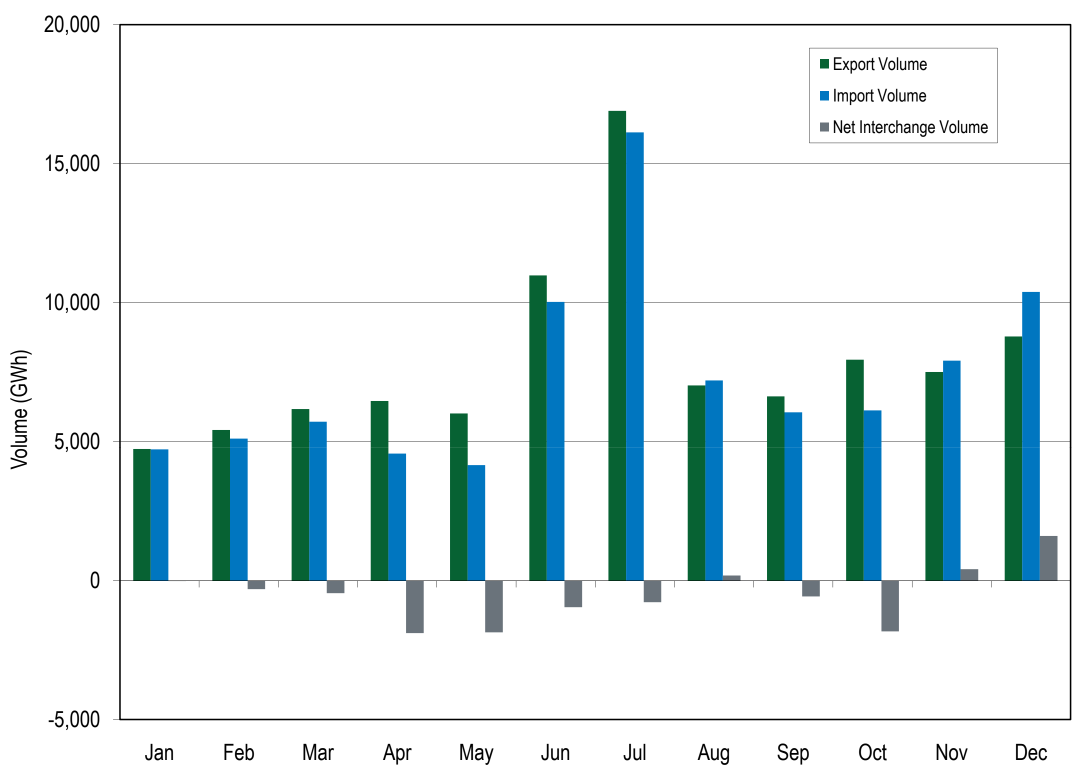
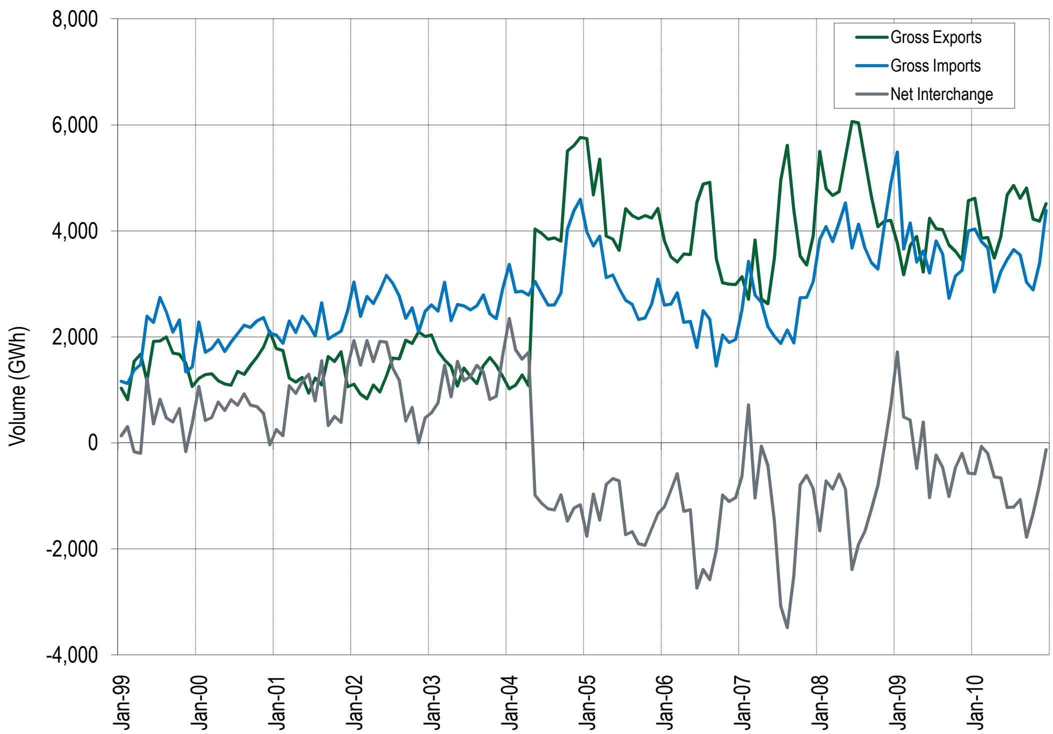


Figure 4-3 shows the real-time import and export volume for PJM from 1999 through 2010. PJM became a consistent net exporter of energy in 2004, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time.

Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through December 2010



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 interfaces 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 2010 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 Energy Market is shown by interface for 2010 in Table 4-4, while gross imports and exports are shown in Table 4-5 and Table 4-6.

In 2010, there were net exports in the Real-Time Energy Market at 16 of PJM's 21 interfaces. (See Table 4-7 for active interfaces in 2010). The top three net exporting interfaces in the Real-Time Energy Market accounted for 70 percent of the total net exports: PJM/NYIS with 30 percent, PJM/NEPT with 20 percent and PJM/MEC with 20 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 Energy Market.

Figure 4-9 shows that PJM's PJM/NYIS average hourly interface price was $2.95 greater than the NYISO's NYIS/PJM Interface price. Net exports are not consistent with purchasing at a lower price and selling at a higher price. The flows were consistent with the price differentials in 49 percent of all hours in 2010. The PJM/NEPT flow averaged approximately -544 MW, and the PJM/LIND flow averaged approximately -139 MW for each hour through 2010. The PJM/NEPT Interface price was, on average lower than the NYIS/NEPT bus price ($51.40 in PJM vs. $58.08 in the NYISO). Similarly, the PJM/LIND Interface price averaged $50.10, while the NYISO/Linden bus price averaged $51.58. The average hourly flows at the PJM/NEPT and PJM/LIND Interfaces were consistent with the average price differentials in 2010. The scheduled flows at the PJM/NEPT Interface were consistent with the price differentials in only 64 percent of all hours in 2010, and the scheduled flows at the PJM/LIND Interface were consistent with the price differentials in only 61 percent of all hours in 2010.

In 2010, there were net exports in the Day-Ahead Energy Market at 12 of PJM's 21 interfaces. The top four exporting interfaces accounted for 92 percent of PJM's total net exports, PJM/NYIS with 33 percent, PJM/ALTW with 25 percent, PJM/MEC with 18 percent and PJM/NEPT with 16 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 50 percent of the total net PJM exports in the Day-Ahead Energy Market.

There were net imports in the Real-Time Energy Market at four of PJM's interfaces. Two net importing interfaces accounted for 90 percent of PJM's net import volume, PJM/OVEC with 78 percent and PJM/LG&E Energy, L.L.C. with 12 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.[14] OVEC itself does not serve load, and therefore does not generally 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.

There were net imports in the Day-Ahead Energy Market at nine of PJM's 21 interfaces. The top two net importing interfaces accounted for 78 percent of PJM's total net imports, PJM/OVEC with 47 percent and PJM/MECS with 31 percent.

14 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 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(70.4)	(72.8)	(40.8)	(141.2)	(114.0)	(154.2)	(150.1)	(162.4)	(154.8)	(172.5)	(126.6)	(227.8)	(1,587.6)
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	219.7	92.2	(32.8)	(22.9)	123.6	(116.4)	(50.8)	(21.0)	(113.3)	(33.9)	(146.1)	52.0	(49.7)
EKPC	(65.5)	(99.2)	14.1	39.3	(0.2)	(19.5)	81.2	88.4	(43.5)	(32.1)	(63.2)	(79.9)	(180.1)
LGEE	31.9	144.5	29.7	44.1	116.8	130.0	160.3	103.4	185.4	290.7	262.4	252.3	1,751.5
MEC	(454.2)	(422.0)	(458.1)	(383.0)	(436.0)	(429.4)	(440.7)	(402.4)	(420.2)	(453.9)	(435.6)	(428.7)	(5,164.2)
MISO	(74.1)	512.4	510.7	8.1	188.5	(327.7)	(658.1)	(550.5)	(945.7)	(767.9)	(334.4)	(74.9)	(2,513.6)
ALTE	3.6	(9.5)	13.7	(7.1)	(0.7)	(66.2)	(90.3)	(46.3)	(116.0)	(64.5)	(62.1)	(146.2)	(591.6)
ALTW	(32.1)	(8.4)	1.4	(16.1)	(27.7)	(148.3)	(80.2)	(54.7)	(106.3)	(70.3)	(58.1)	(44.9)	(645.7)
AMIL	(141.6)	(85.5)	(63.5)	(25.6)	37.1	18.8	22.1	77.6	(7.4)	(12.8)	(11.8)	(30.7)	(223.3)
CIN	78.4	323.4	233.5	(112.2)	189.0	155.8	(37.8)	(52.3)	(333.5)	(307.7)	(70.4)	(54.4)	11.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(13.8)	(8.5)	0.0	0.0	(22.3)
FE	(117.4)	(60.2)	(70.6)	(114.3)	(142.5)	(173.5)	(182.1)	(211.3)	(86.1)	(86.9)	(96.5)	110.3	(1,231.1)
IPL	(28.4)	48.4	(4.6)	112.6	61.3	(61.2)	(177.9)	(121.3)	(170.1)	4.3	(8.3)	6.2	(339.0)
MECS	195.1	312.7	387.5	199.7	95.9	103.2	34.9	0.5	20.1	(101.2)	61.2	238.3	1,547.9
NIPS	(24.0)	(10.8)	(4.9)	(0.6)	(1.9)	(111.1)	(98.2)	(49.9)	(56.7)	(43.4)	(33.8)	(63.2)	(498.5)
WEC	(7.7)	2.3	18.2	(28.3)	(22.0)	(45.2)	(48.6)	(92.8)	(75.9)	(76.9)	(54.6)	(90.3)	(521.8)
NYISO	(1,307.0)	(1,039.9)	(1,109.6)	(950.3)	(1,334.9)	(1,257.1)	(1,003.0)	(1,029.6)	(1,219.8)	(1,145.5)	(1,143.5)	(963.0)	(13,503.2)
LIND	(146.0)	(125.5)	(115.7)	(75.8)	(89.8)	(100.4)	(99.2)	(63.6)	(113.0)	(114.0)	(95.1)	(106.5)	(1,244.6)
NEPT	(496.7)	(423.6)	(449.9)	(280.9)	(464.8)	(466.6)	(411.5)	(292.7)	(375.7)	(391.0)	(419.5)	(379.9)	(4,852.8)
NYIS	(664.3)	(490.8)	(544.0)	(593.6)	(780.3)	(690.1)	(492.3)	(673.3)	(731.1)	(640.5)	(628.9)	(476.6)	(7,405.8)
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	781.7	1,004.6	931.1	947.2	1,149.0	1,198.8	11,812.9
TVA	(39.0)	(121.5)	(129.3)	(88.3)	(7.8)	(43.4)	69.0	(97.4)	2.7	32.5	50.6	144.9	(227.0)
Total	(581.7)	(63.3)	(197.3)	(640.2)	(658.1)	(1,215.8)	(1,210.5)	(1,066.9)	(1,778.1)	(1,335.4)	(787.4)	(126.3)	(9,661.0)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	128.3	113.4	99.8	0.6	22.7	9.9	28.2	26.5	6.4	9.9	12.8	23.4	481.9
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	408.5	235.2	135.1	142.6	258.6	174.8	229.5	243.7	104.5	113.3	166.6	248.9	2,461.3
EKPC	15.8	3.0	53.9	58.1	34.8	36.6	88.9	104.2	22.6	10.2	9.7	7.8	445.6
LGEE	48.9	150.5	73.5	58.7	135.6	161.8	187.6	171.8	218.2	297.3	267.4	274.9	2,046.2
MEC	44.1	28.1	35.7	52.3	61.5	34.7	41.7	46.5	43.7	24.5	32.7	54.8	500.3
MISO	1,142.9	1,388.4	1,292.1	852.6	907.3	1,055.0	866.6	748.7	656.4	503.7	729.3	1,303.8	11,446.8
ALTE	30.0	8.0	28.9	2.4	9.4	1.0	1.3	6.7	3.3	9.4	4.2	0.0	104.6
ALTW	0.0	5.4	7.6	1.1	2.8	6.3	7.6	17.6	14.5	12.4	20.8	5.3	101.4
AMIL	23.5	49.2	39.2	45.6	55.0	37.1	33.3	88.8	17.3	11.6	9.6	20.2	430.4
CIN	500.9	555.4	454.8	227.2	364.7	551.6	366.0	314.9	216.4	149.9	343.6	507.9	4,553.3
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	181.6	207.6	205.4	156.0	147.5	162.3	176.9	150.8	218.3	186.5	178.8	333.1	2,304.8
IPL	47.1	116.7	16.2	115.9	113.5	71.8	16.0	1.5	4.3	8.2	4.6	26.4	542.2
MECS	304.3	385.9	475.1	283.7	181.5	185.2	215.2	150.5	170.9	122.3	156.9	408.9	3,040.4
NIPS	0.0	0.0	0.0	0.2	13.4	6.4	2.9	14.7	10.8	0.4	0.0	2.0	50.8
WEC	55.5	60.2	64.9	20.5	19.5	33.3	47.4	3.2	0.6	3.0	10.8	0.0	318.9
NYISO	934.4	901.2	922.5	765.7	890.8	916.1	1,184.7	1,084.6	916.6	896.8	884.9	1,010.0	11,308.3
LIND	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
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	934.4	901.2	922.5	765.7	890.8	916.1	1,184.7	1,084.6	916.6	896.8	884.9	1,010.0	11,308.3
OVEC	1,176.9	943.0	1,018.8	854.0	805.9	1,001.9	781.7	1,004.6	931.1	947.2	1,149.0	1,226.7	11,840.8
TVA	134.6	35.7	47.7	63.0	115.6	67.9	237.4	116.4	131.8	85.1	142.9	237.4	1,415.5
Total	4,034.4	3,798.5	3,679.1	2,847.6	3,232.8	3,458.7	3,646.3	3,547.0	3,031.3	2,888.0	3,395.3	4,387.7	41,946.7

Table 4-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	198.7	186.2	140.6	141.8	136.7	164.1	178.3	188.9	161.2	182.4	139.4	251.2	2,069.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	188.8	143.0	167.9	165.5	135.0	291.2	280.3	264.7	217.8	147.2	312.7	196.9	2,511.0
EKPC	81.3	102.2	39.8	18.8	35.0	56.1	7.7	15.8	66.1	42.3	72.9	87.7	625.7
LGEE	17.0	6.0	43.8	14.6	18.8	31.8	27.3	68.4	32.8	6.6	5.0	22.6	294.7
MEC	498.3	450.1	493.8	435.3	497.5	464.1	482.4	448.9	463.9	478.4	468.3	483.5	5,664.5
MISO	1,217.0	876.0	781.4	844.5	718.8	1,382.7	1,524.7	1,299.2	1,602.1	1,271.6	1,063.7	1,378.7	13,960.4
ALTE	26.4	17.5	15.2	9.5	10.1	67.2	91.6	53.0	119.3	73.9	66.3	146.2	696.2
ALTW	32.1	13.8	6.2	17.2	30.5	154.6	87.8	72.3	120.8	82.7	78.9	50.2	747.1
AMIL	165.1	134.7	102.7	71.2	17.9	18.3	11.2	11.2	24.7	24.4	21.4	50.9	653.7
CIN	422.5	232.0	221.3	339.4	175.7	395.8	403.8	367.2	549.9	457.6	414.0	562.3	4,541.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.8	8.5	0.0	0.0	22.3
FE	299.0	267.8	276.0	270.3	290.0	335.8	359.0	362.1	304.4	273.4	275.3	222.8	3,535.9
IPL	75.5	68.3	20.8	3.3	52.2	133.0	193.9	122.8	174.4	3.9	12.9	20.2	881.2
MECS	109.2	73.2	87.6	84.0	85.6	82.0	180.3	150.0	150.8	223.5	95.7	170.6	1,492.5
NIPS	24.0	10.8	4.9	0.8	15.3	117.5	101.1	64.6	67.5	43.8	33.8	65.2	549.3
WEC	63.2	57.9	46.7	48.8	41.5	78.5	96.0	96.0	76.5	79.9	65.4	90.3	840.7
NYISO	2,241.4	1,941.1	2,032.1	1,716.0	2,225.7	2,173.2	2,187.7	2,114.2	2,136.4	2,042.3	2,028.4	1,973.0	24,811.5
LIND	146.0	125.5	115.7	75.8	89.8	100.4	99.2	63.6	113.0	114.0	95.1	106.5	1,244.6
NEPT	496.7	423.6	449.9	280.9	464.8	466.6	411.5	292.7	375.7	391.0	419.5	379.9	4,852.8
NYIS	1,598.7	1,392.0	1,466.5	1,359.3	1,671.1	1,606.2	1,677.0	1,757.9	1,647.7	1,537.3	1,513.8	1,486.6	18,714.1
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.9	27.9
TVA	173.6	157.2	177.0	151.3	123.4	111.3	168.4	213.8	129.1	52.6	92.3	92.5	1,642.5
Total	4,616.1	3,861.8	3,876.4	3,487.8	3,890.9	4,674.5	4,856.8	4,613.9	4,809.4	4,223.4	4,182.7	4,514.0	51,607.7

Table 4-4 Day-ahead net interchange volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(89.3)	(111.3)	(114.7)	(122.2)	(108.3)	(134.2)	372.0	(119.5)	(70.8)	(129.3)	(206.7)	(141.3)	(975.6)
CPLW	10.2	(1.0)	1.0	(0.9)	(1.0)	(1.5)	6.7	2.0	5.6	7.9	4.6	19.7	53.3
DUK	161.4	38.4	8.6	12.6	72.5	23.2	(222.7)	(100.4)	29.2	17.2	64.5	65.6	170.1
EKPC	(1.5)	(5.9)	(3.4)	(0.2)	(1.4)	(3.0)	(4.5)	(3.5)	(0.1)	0.0	0.1	0.1	(23.3)
LGEE	1.0	5.3	0.0	(0.1)	1.4	(8.0)	(13.7)	(51.5)	(3.7)	0.9	0.0	0.0	(68.4)
MEC	(479.4)	(444.1)	(482.8)	(433.0)	(464.1)	(789.0)	(374.3)	(457.0)	(448.1)	(477.0)	(468.6)	(428.7)	(5,746.1)
MISO	282.3	(160.5)	(312.1)	(1,450.5)	(1,018.5)	550.4	3,478.1	820.5	79.0	(1,128.3)	983.6	2,083.3	4,207.3
ALTE	227.6	(257.5)	(136.2)	(302.4)	(711.0)	(168.0)	73.0	145.9	(9.0)	(403.9)	315.8	1,466.5	240.8
ALTW	(282.2)	(414.3)	(1,220.9)	(1,761.3)	(766.8)	(2,195.9)	(1,908.2)	(567.7)	68.1	437.3	663.7	273.4	(7,674.8)
AMIL	14.4	97.5	6.7	12.4	44.5	114.6	1.7	9.0	(1.3)	(6.4)	19.7	80.1	392.9
CIN	182.9	(60.8)	43.1	(70.3)	41.8	310.0	1,376.9	161.3	4.2	(215.5)	(11.0)	(88.6)	1,674.0
CWLP	0.0	0.0	0.0	0.0	(0.3)	0.0	(19.5)	0.0	(11.8)	(8.5)	0.0	0.0	(40.1)
FE	(70.5)	(20.7)	118.8	(72.4)	(79.3)	390.4	1,007.5	20.4	(218.3)	(519.1)	(112.7)	(107.6)	336.5
IPL	(53.4)	(18.4)	(44.7)	(8.5)	(42.0)	68.9	131.8	41.7	(41.0)	(54.2)	(44.8)	(131.3)	(195.9)
MECS	387.8	654.4	885.6	732.9	546.6	1,223.9	1,484.6	767.5	379.5	(263.9)	247.4	681.6	7,727.9
NIPS	(204.5)	(217.0)	(143.3)	(87.6)	(120.2)	(103.9)	394.9	(34.3)	(67.1)	(49.7)	(43.8)	(65.1)	(741.6)
WEC	80.2	76.3	178.8	106.7	68.2	910.4	935.4	276.7	(24.3)	(44.4)	(50.7)	(25.7)	2,487.6
NYISO	(969.0)	(912.0)	(825.4)	(752.7)	(1,017.9)	(1,657.9)	(4,727.8)	(904.8)	(894.0)	(945.2)	(948.1)	(973.6)	(15,528.4)
LIND	(21.1)	(18.3)	(53.2)	(11.4)	(15.3)	(12.0)	(24.7)	(9.9)	(53.2)	(50.8)	(47.9)	(66.3)	(384.1)
NEPT	(502.6)	(445.2)	(456.7)	(301.3)	(473.4)	(472.7)	(420.9)	(317.7)	(374.8)	(392.2)	(423.9)	(407.1)	(4,988.5)
NYIS	(445.3)	(448.5)	(315.5)	(440.0)	(529.2)	(1,173.2)	(4,282.2)	(577.2)	(466.0)	(502.2)	(476.3)	(500.2)	(10,155.8)
OVEC	1,074.0	1,243.3	1,300.5	917.1	679.0	1,058.2	1,045.7	978.5	711.5	740.6	853.3	970.1	11,571.8
TVA	(5.3)	37.8	(27.0)	(60.9)	(5.4)	7.7	(335.1)	16.4	18.0	87.4	127.9	7.8	(130.7)
Total	(15.6)	(310.0)	(455.3)	(1,890.8)	(1,863.7)	(954.1)	(775.6)	180.7	(573.4)	(1,825.8)	410.6	1,603.0	(6,470.0)

Table 4-5 Day-ahead gross import volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	64.2	39.5	29.3	10.7	15.8	49.1	595.7	124.6	89.2	37.7	57.5	138.4	1,251.7
CPLW	15.6	0.6	1.8	0.0	1.4	0.8	6.7	2.0	7.1	8.5	4.7	19.7	68.9
DUK	176.3	96.2	48.1	40.2	107.2	77.8	139.9	112.9	108.6	66.2	105.1	135.0	1,213.5
EKPC	0.0	0.0	0.4	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.1	0.8
LGEE	1.0	5.4	0.0	0.0	1.8	0.5	1.4	6.5	2.2	12.1	2.4	0.0	33.3
MEC	18.8	5.6	12.2	18.6	70.2	158.8	247.8	33.6	20.7	1.4	0.0	56.5	644.2
MISO	2,400.5	2,738.3	3,112.5	2,678.8	2,251.6	7,455.1	12,488.8	4,596.2	3,905.6	3,782.4	5,158.0	7,350.2	57,918.0
ALTE	866.4	762.4	662.8	382.9	263.8	721.2	2,191.6	1,241.3	1,728.4	1,650.5	2,471.8	4,524.1	17,467.2
ALTW	72.0	67.2	72.4	53.6	40.2	345.7	896.3	257.6	542.7	863.2	1,014.1	464.7	4,689.7
AMIL	68.1	157.9	50.5	32.1	44.8	114.6	1.7	10.5	4.5	4.1	29.5	88.7	607.0
CIN	436.8	592.0	555.1	590.4	430.6	969.6	1,988.3	701.1	238.3	118.6	139.5	127.9	6,888.2
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	156.2	176.9	364.9	203.7	179.3	752.7	1,536.1	519.1	204.8	125.7	327.1	299.4	4,845.9
IPL	26.9	29.4	30.7	102.8	97.0	1,045.3	1,004.8	124.0	16.8	4.0	30.3	9.9	2,521.9
MECS	606.2	801.7	1,125.2	1,118.7	1,035.2	2,223.8	2,629.9	1,246.7	1,060.7	787.7	848.1	1,446.8	14,930.7
NIPS	28.6	19.5	24.3	33.1	26.9	292.1	1,115.1	84.5	19.3	45.0	93.0	154.7	1,936.1
WEC	139.3	131.3	226.6	161.5	133.8	990.1	1,125.0	411.4	90.1	183.6	204.6	234.0	4,031.3
NYISO	835.3	885.1	1,095.7	883.7	858.1	1,165.0	1,202.9	1,219.8	1,047.4	1,048.7	1,069.3	1,115.3	12,426.3
LIND	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
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	835.3	885.1	1,095.7	883.7	858.1	1,165.0	1,202.9	1,219.8	1,047.4	1,048.7	1,069.3	1,115.3	12,426.3
OVEC	1,133.2	1,259.7	1,379.9	922.0	802.1	1,063.8	1,086.8	985.3	793.4	925.9	1,199.3	1,299.9	12,851.3
TVA	75.9	77.8	36.7	15.2	44.4	55.3	357.2	120.3	79.1	239.1	316.3	273.9	1,691.2
Total	4,720.8	5,108.2	5,716.6	4,569.2	4,152.6	10,026.2	16,127.4	7,201.2	6,053.3	6,122.0	7,912.7	10,389.0	88,099.2

Table 4-6 Day-ahead gross export volume by interface (GWh): Calendar year 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	153.5	150.8	144.0	132.9	124.1	183.3	223.7	244.1	160.0	167.0	264.2	279.7	2,227.3
CPLW	5.4	1.6	0.8	0.9	2.4	2.3	0.0	0.0	1.5	0.6	0.1	0.0	15.6
DUK	14.9	57.8	39.5	27.6	34.7	54.6	362.6	213.3	79.4	49.0	40.6	69.4	1,043.4
EKPC	1.5	5.9	3.8	0.2	1.4	3.0	4.7	3.5	0.1	0.0	0.0	0.0	24.1
LGEE	0.0	0.1	0.0	0.1	0.4	8.5	15.1	58.0	5.9	11.2	2.4	0.0	101.7
MEC	498.2	449.7	495.0	451.6	534.3	947.8	622.1	490.6	468.8	478.4	468.6	485.2	6,390.3
MISO	2,118.2	2,898.8	3,424.6	4,129.3	3,270.1	6,904.7	9,010.7	3,775.7	3,826.6	4,910.7	4,174.4	5,266.9	53,710.7
ALTE	638.8	1,019.9	799.0	685.3	974.8	889.2	2,118.6	1,095.4	1,737.4	2,054.4	2,156.0	3,057.6	17,226.4
ALTW	354.2	481.5	1,293.3	1,814.9	807.0	2,541.6	2,804.5	825.3	474.6	425.9	350.4	191.3	12,364.5
AMIL	53.7	60.4	43.8	19.7	0.3	0.0	0.0	1.5	5.8	10.5	9.8	8.6	214.1
CIN	253.9	652.8	512.0	660.7	388.8	659.6	611.4	539.8	234.1	334.1	150.5	216.5	5,214.2
CWLP	0.0	0.0	0.0	0.0	0.3	0.0	19.5	0.0	11.8	8.5	0.0	0.0	40.1
FE	226.7	197.6	246.1	276.1	258.6	362.3	528.6	498.7	423.1	644.8	439.8	407.0	4,509.4
IPL	80.3	47.8	75.4	111.3	139.0	976.4	873.0	82.3	57.8	58.2	75.1	141.2	2,717.8
MECS	218.4	147.3	239.6	385.8	488.6	999.9	1,145.3	479.2	681.2	1,051.6	600.7	765.2	7,202.8
NIPS	233.1	236.5	167.6	120.7	147.1	396.0	720.2	118.8	86.4	94.7	136.8	219.8	2,677.7
WEC	59.1	55.0	47.8	54.8	65.6	79.7	189.6	134.7	114.4	228.0	255.3	259.7	1,543.7
NYISO	1,804.3	1,797.1	1,921.1	1,636.4	1,876.0	2,822.9	5,930.7	2,124.6	1,941.4	1,993.9	2,017.4	2,088.9	27,954.7
LIND	21.1	18.3	53.2	11.4	15.3	12.0	24.7	9.9	53.2	50.8	47.9	66.3	384.1
NEPT	502.6	445.2	456.7	301.3	473.4	472.7	420.9	317.7	374.8	392.2	423.9	407.1	4,988.5
NYIS	1,280.6	1,333.6	1,411.2	1,323.7	1,387.3	2,338.2	5,485.1	1,797.0	1,513.4	1,550.9	1,545.6	1,615.5	22,582.1
OVEC	59.2	16.4	79.4	4.9	123.1	5.6	41.1	6.8	81.9	185.3	346.0	329.8	1,279.5
TVA	81.2	40.0	63.7	76.1	49.8	47.6	692.3	103.9	61.1	151.7	188.4	266.1	1,821.9
Total	4,736.4	5,418.2	6,171.9	6,460.0	6,016.3	10,980.3	16,903.0	7,020.5	6,626.7	7,947.8	7,502.1	8,786.0	94,569.2

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 Energy Market requires fewer steps than the Real-Time Energy 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 Energy Market.[15] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow. In the Day-Ahead Energy 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 Energy 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 import or export pricing point. 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 Energy Market. These approved transactions are a financial obligation. If the market participant does not provide a corresponding transaction in the Real-Time Energy 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 Energy 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 Energy Market are similar to those in the Real-Time Energy 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 Energy Market represent a financial obligation. If the market participant does not meet the commitment in the Real-Time Energy Market, they are subject to the balancing market settlement.

Source and Sink in the Real-Time Energy Market

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

- **Real-Time Energy 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

15 On September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the “Up-to Congestion” heading in this report.

reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA'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 Energy 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 TVA, the sink would initially default to TVA'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 Energy 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 TVA and the POD is NYIS, the source would initially default to TVA'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 Energy Market

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

- **Day-Ahead Energy 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 Energy 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 Energy 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. For importing dispatchable transactions, 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 2010. 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.[16] 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.[17] 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, which 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.[18] Table 4-8 presents the interface pricing points used in 2010.

Table 4-7 Active interfaces: Calendar year 2010

	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	Active	Active	Active	Active	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

16 See "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>.

17 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).

18 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

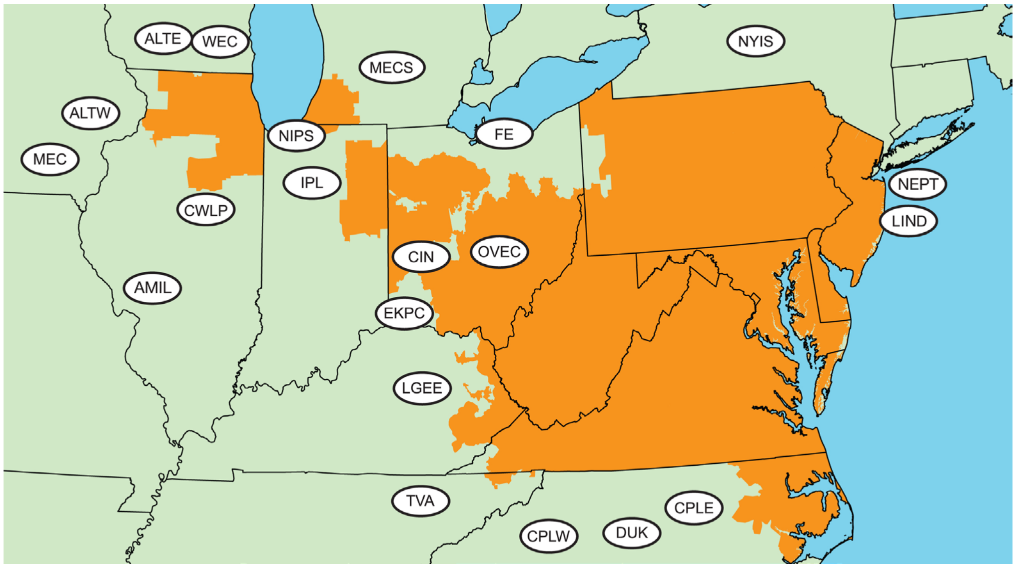


Table 4-8 Active pricing points: 2010

PJM 2010 Pricing Points				
CPLEEXP	CPLEIMP	DUKEXP	DUKIMP	LIND
MICHFE	MISO	NCMPAEXP	NCMPAIMP	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO	OVEC
SOUTHEXP	SOUTHIMP			

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

In 2010, the direction of power flows at the borders between PJM and the Midwest ISO and between PJM and the NYISO was not consistent with real-time energy market price differences for a majority of hours, 58 percent between PJM and the Midwest ISO and 51 percent between PJM and NYISO. The MMU recommends that PJM work with both Midwest ISO and NYISO to improve the ways in which interface prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by reliance on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag. PJM is engaged in preliminary discussions with both Midwest ISO and NYISO on interface pricing.

PJM and Midwest ISO Interface Prices

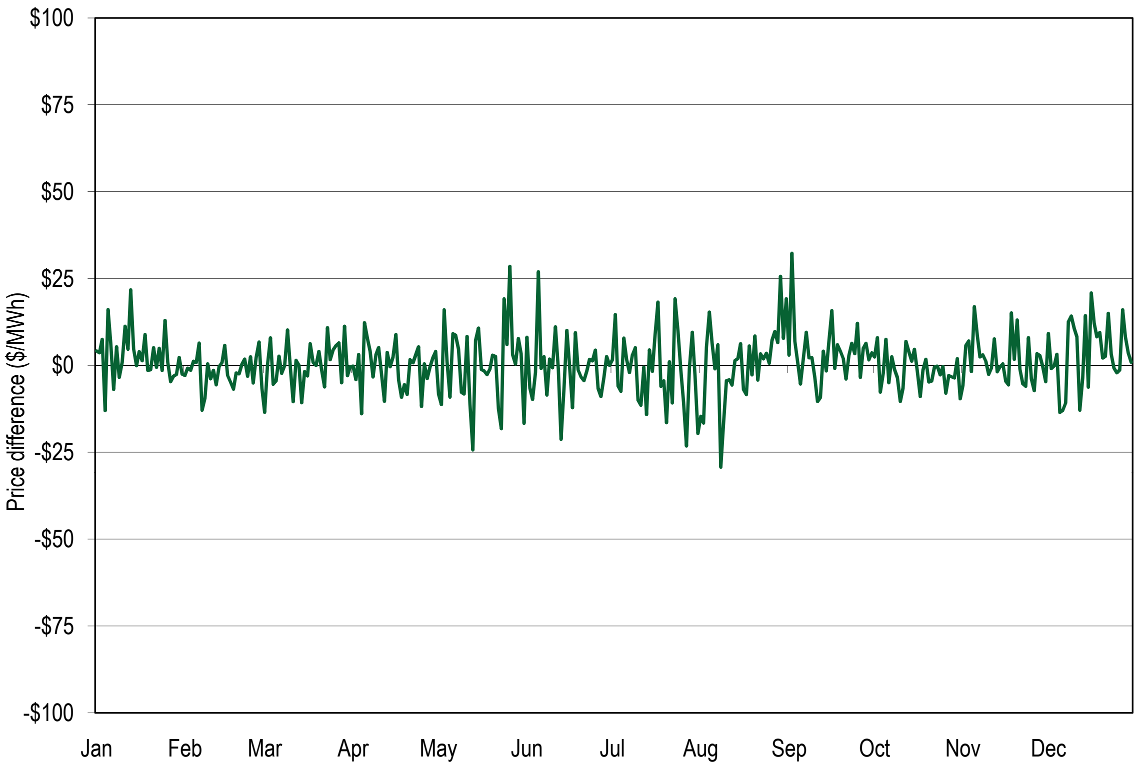
Both the PJM/MISO and the MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from the Midwest ISO would receive the 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[19] 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.[20]

Real-Time Prices

In 2010, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2010, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $33.33 while the Midwest ISO LMP at the border was $33.90, a difference of $0.57, while the average hourly flow in 2010 was -918 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 42 percent of hours of 2010. While the average hourly LMP difference at the PJM/MISO border was only $0.57, the average of the absolute value of the hourly difference was $11.64. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $51.5 million at the PJM/MISO Interface.

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

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2010



The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 4-5). 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.

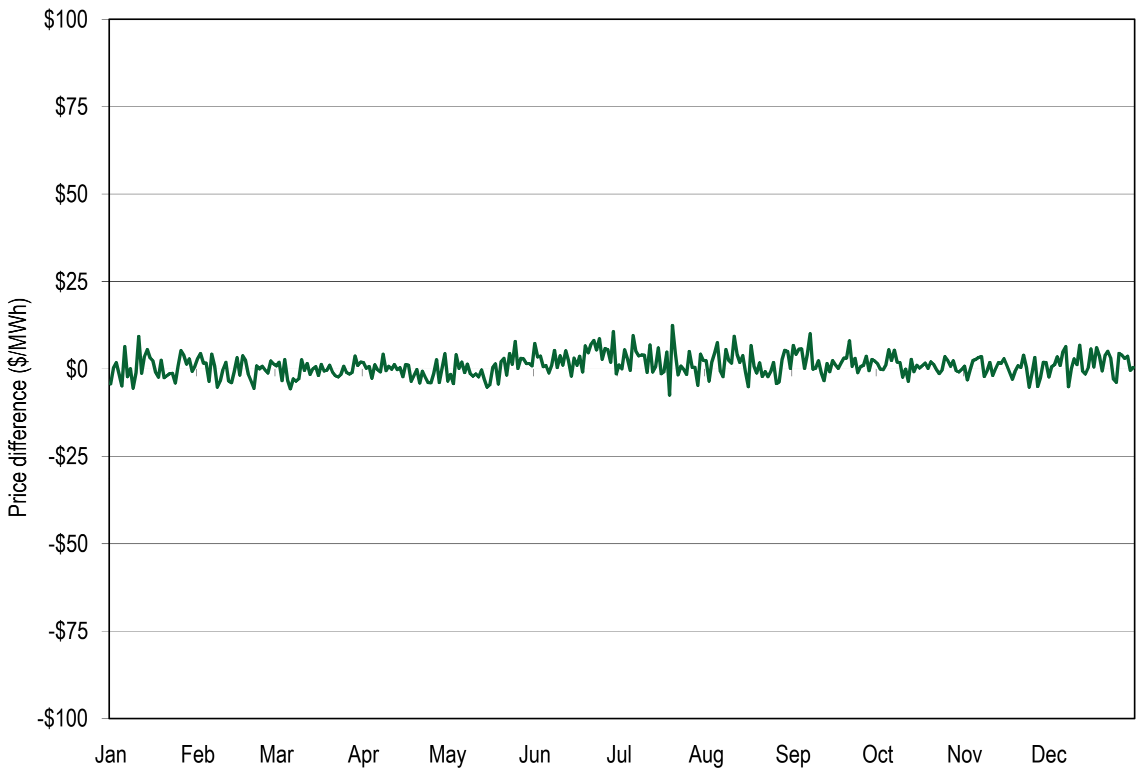
In 2010, the difference between the real-time PJM/MISO Interface price and the real-time MISO/PJM Interface price fluctuated between positive and negative about eight times per day. The standard deviation of the hourly price was $18.37 for the PJM/MISO Interface price and $20.72 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $20.50. The average of the absolute value of the hourly price difference was $11.64. Absolute values reflect price differences regardless of whether they are positive or negative.

The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, although with a lag that permits substantial price differences in both directions.

Day-Ahead Prices

The 2010 day-ahead hourly average interface prices for PJM/MISO and MISO/PJM were $34.83 and $33.87. The simple average difference between the day-ahead MISO/PJM Interface price and the PJM/MISO Interface was $0.96 in 2010 (Figure 4-6). In the Day-Ahead Energy Market, gross exports to the Midwest ISO were 53,710.7 GWh in 2010.

Figure 4-6 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): Calendar year 2010



In 2010, 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 $13.05 for the PJM/MISO price and $13.89 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $5.12. The average of the absolute value of the hourly price difference was $3.58.

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.

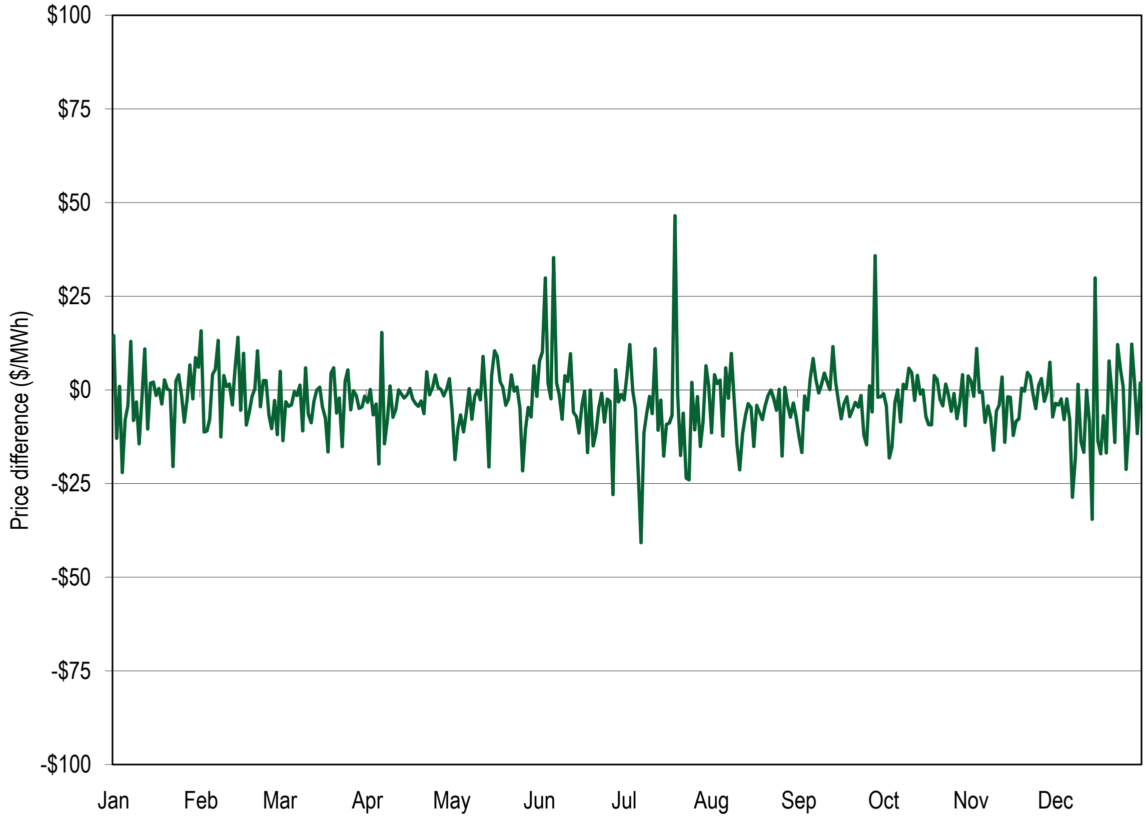
PJM's price for transactions with the NYISO (excluding those transactions across the Neptune and Linden lines), termed the NYIS Interface pricing point by PJM, represents the value of power at the PJM/NYISO border, as determined by the PJM market. PJM defines its NYIS Interface pricing point using two buses.[21] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO/PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

Real-Time Prices

In 2010, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In 2010, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was not consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the PJM/NYISO border was $47.64 while the NYISO LMP at the border was $44.69, a difference of $2.95, while the average hourly flow was -722 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is not consistent with the fact that the average PJM price was higher than the average NYISO price.) The direction of flows was consistent with price differentials in only 49 percent of the hours. While the average hourly LMP difference at the PJM/NYISO border was only $2.95, the average of the absolute value of the hourly difference was $14.74. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $52.7 million at the PJM/NYIS Interface.

21 See "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>.

Figure 4-7 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2010



The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 4-8). 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.

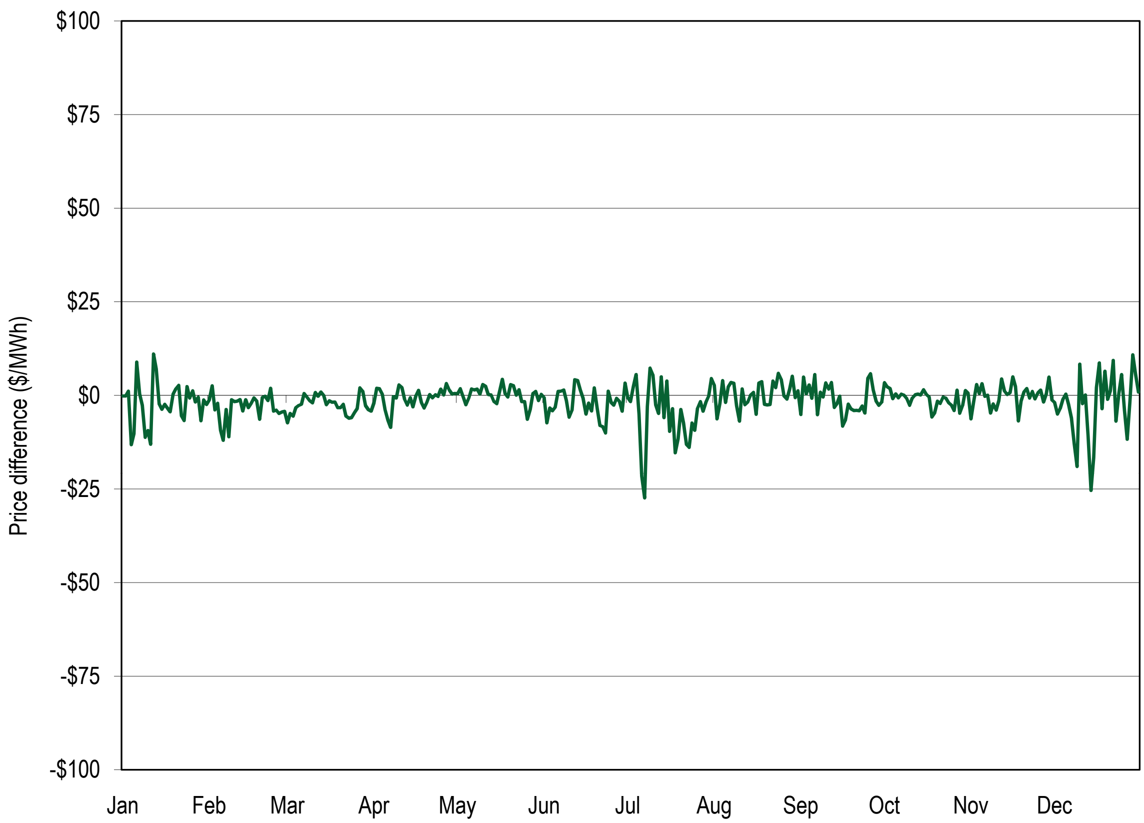
The difference between the real-time PJM/NYIS Interface price and the real-time NYISO/PJM proxy bus price continued to fluctuate between positive and negative about eight times per day in 2010 as it has since 2003. The standard deviation of hourly price was $28.58 in 2010 for the PJM/NYIS Interface price and $31.84 in 2010 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $31.02 in 2010. The average of the absolute value of the hourly price difference was $14.74 in 2010. Absolute values reflect price differences without regard to whether they are positive or negative.

Day-Ahead Prices

The 2010 day-ahead hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $46.53 and $48.11. The simple average difference between the day-ahead PJM/NYISO Interface price and the NYISO/PJM proxy bus price was $1.58 in 2010 (Figure 4-8). In the Day-Ahead Energy Market, the gross exports to the NYISO were 22,582.1 GWh in 2010.

The difference between the day-ahead PJM/NYIS Interface price and the day-ahead NYISO/PJM proxy bus price fluctuated between positive and negative about four times per day in 2010. The standard deviation of hourly price was $20.08 in 2010 for the PJM/NYIS Interface price and $16.79 in 2010 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $7.09 in 2010. The average of the absolute value of the hourly price difference was $4.73 in 2010. Absolute values reflect price differences without regard to whether they are positive or negative.

Figure 4-8 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2010



Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-9 and Figure 4-10, including average prices and measures of variability.

Figure 4-9 PJM, NYISO and Midwest ISO real-time border price averages: Calendar year 2010

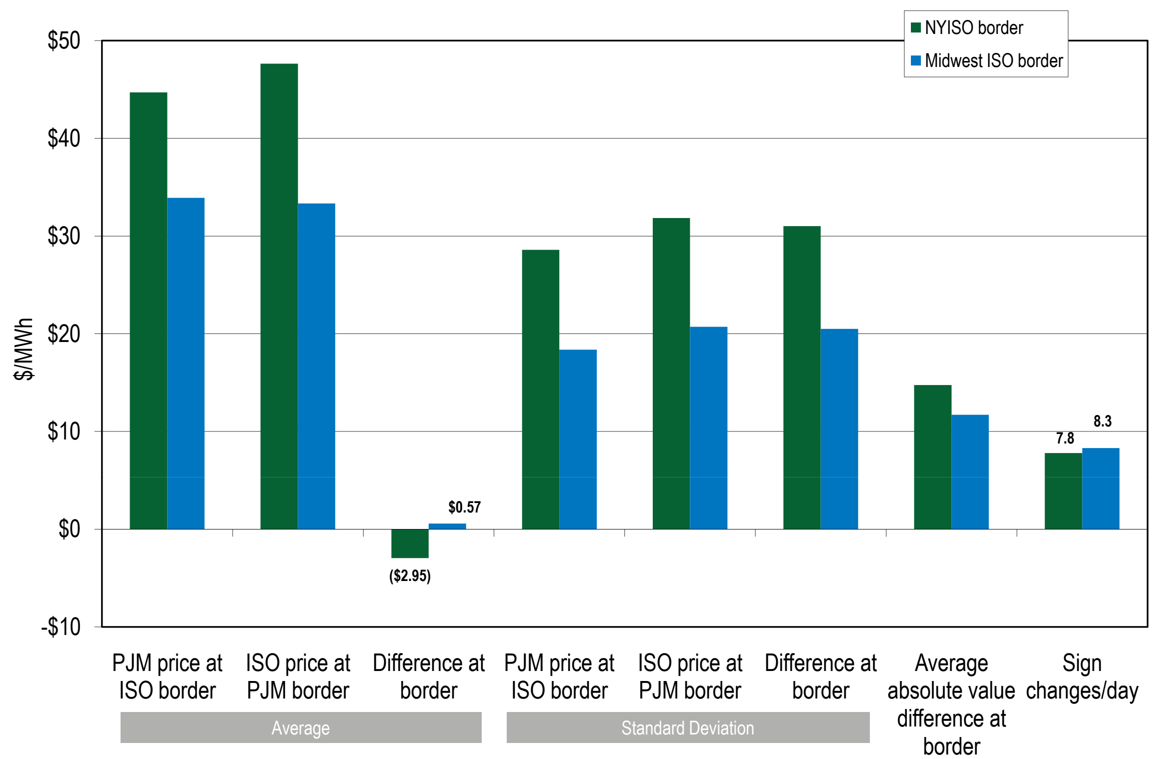
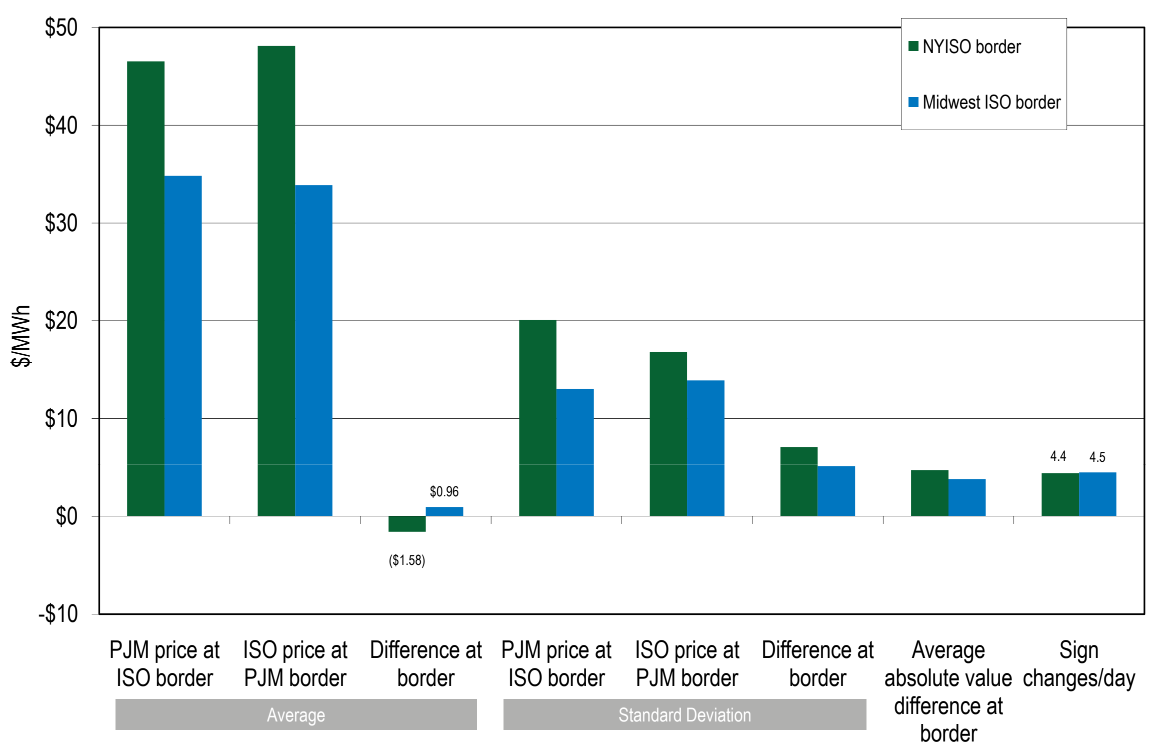


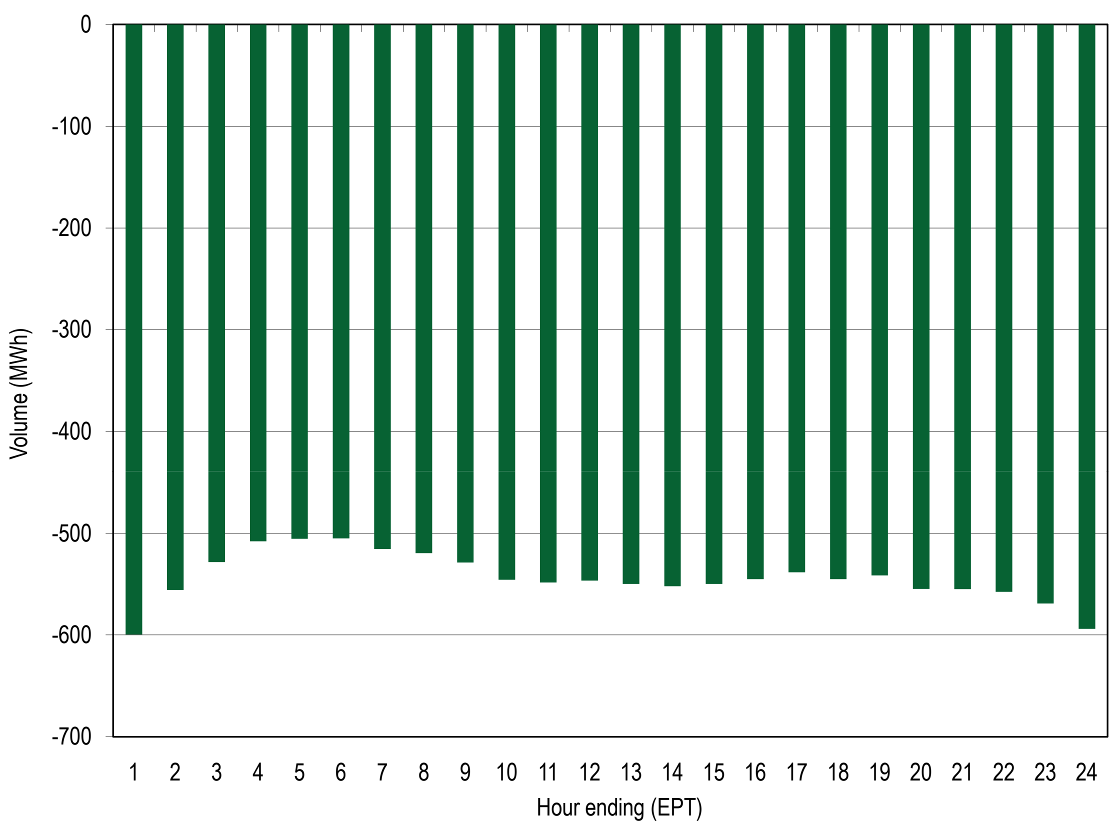
Figure 4-10 PJM, NYISO and Midwest ISO day-ahead border price averages: Calendar year 2010



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. For 2010, the total real-time scheduled net exports on the Neptune line were 4,853 GWh while the day-ahead scheduled net exports were 4,989 GWh. Figure 4-11 shows the real-time average flow, by hour of the day, on the Neptune line for the calendar year 2010. In 2010, the average price difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Neptune Interface was $51.40 while the NYISO LMP at the Neptune Bus was $58.08, a difference of $6.67, while the average hourly flow in 2010 was -544 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64 percent of the hours. While the average hourly LMP difference at the PJM/Neptune border was only $6.67, the average of the absolute value of the hourly difference was $23.30. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was $43.4 million at the PJM/NEPT Interface.

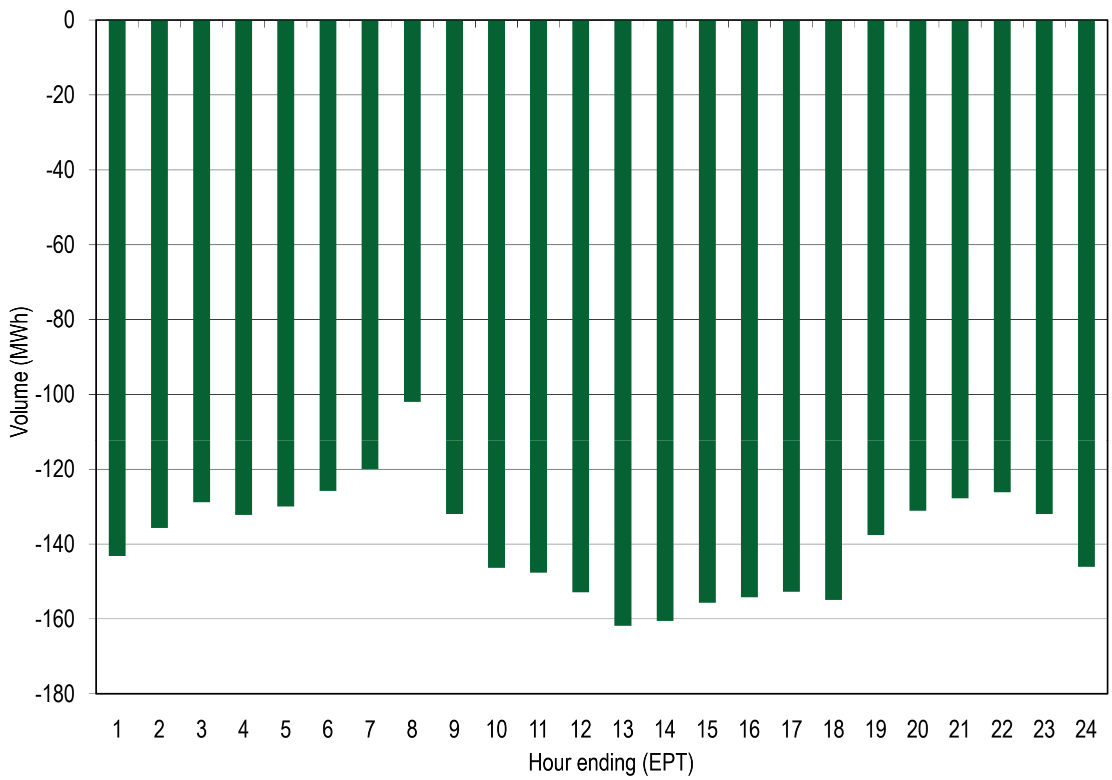
Figure 4-11 Neptune hourly average flow: Calendar year 2010



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. The basis for this limitation is unclear. Figure 4-12 shows the real-time average flow, by hour of the day, on the Linden line for the calendar year 2010. In 2010, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Linden Interface was $50.10 while the NYISO LMP at the Linden Bus was $51.58, a difference of $1.48, while the average hourly flow was -139 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 61 percent of the hours. While the average hourly LMP difference at the PJM/Linden border was only $1.48, the average of the absolute value of the hourly difference was $18.13. During all hours where flows did not align with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was $8.8 million at the PJM/LIND Interface.

Figure 4-12 Linden hourly average flow: January through December 2010



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.

The PJM/NYISO JOA does not include provisions for market based congestion management or other market to market activity, and, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued in 2010. 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."[22] After working in collaboration with PJM, the Midwest ISO and the Ontario Independent Electricity System Operator (IESO), including an opportunity to comment by 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.[23] On July 15, 2010, the Commission conditionally accepted the NYISO Report subject to the parties filing answers to the questions set forth in the order within 30 days of the date of the order.[24] The Commission requested that the parties provide additional evidence regarding the proposed solutions. On August 16, 2010, the NYISO provided their response to the July 15th Order.[25] On September 15, 2010, the Market Monitoring Unit (MMU) responded to the NYISO filing.[26] The MMU commented that the NYISO response lacked detail and focus in implementing solutions that could be implemented quickly, and continued to lack detailed and firm timelines for implementation. Additionally, the MMU questioned the curtailment priority granted to transactions scheduled on non-firm transmission when electing to purchase "buy-through of congestion" as well as the inability to implement a market to market congestion management agreement with PJM. Finally, the MMU provided comments and recommendations on implementing an interface pricing solution in the NYISO to mitigate the incentives to scheduling circuitous paths into and out of the NYISO. The MMU actively participated in the meeting of the Broader Regional Markets Group in Philadelphia on September 27, 2010, and continues to advocate in that process a joint operating agreement between NYISO and PJM that is equivalent to or better than the JOA between the Midwest ISO and PJM. On December 30, 2010, the Commission issued an Order on Rehearing and Compliance which indicated that they agreed with the MMU comments and directed the NYISO to make interface pricing revisions by the second quarter of 2011. Additionally, the Commission required that congestion management/market-to-market coordination for the Commission-jurisdictional RTO/ISOs be completed concurrently by the second quarter of 2011.[27]

22 128 FERC ¶ 61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶ 61,239.
23 See "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (January 12, 2010)
24 See 132 FERC ¶ 61,031.
25 See "Response to Questions and Supplemental Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (August 16, 2010).
26 See "Comments of the Independent Market Monitor for PJM."Docket No. ER08-1281-004 (September 15, 2010).
27 See 133 FERC ¶ 61,276.

PJM and Midwest ISO Joint Operating Agreement

The market to market coordination between PJM and the Midwest ISO continued in 2010. 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 Protocol (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.[28]

Differences also emerged over how the parties are administering the JOA, such as the use by the Midwest ISO of proxy flowgates. The practice of inappropriately using proxy flowgates for market to market activity, if confirmed, measured and determined inconsistent with the JOA, would have meant that the Midwest ISO received more compensation than appropriate.

These matters went before the Commission in settlement proceedings.[29] Two settlement conferences were held on August 4, 2010, and November 3, 2010. The settling parties and interveners discussed the issues raised by the complaints in the proceedings, as well as other issues arising under the JOA that came to light during the course of the discussions, including a newly discovered error in the calculation of Firm Flow Entitlements (FFEs) under the JOA. As a result of the discussions conducted at the settlement conferences, the Midwest ISO and PJM reached a settlement resolving all issues in the proceeding. The settlement includes a dismissal of all complaints within the proceeding. Additionally, "Both parties further agree to release and discharge forever the other, its officers, directors, employees, members, successors, and assigns from any and all claims, demands, damages, amounts owed, actions, causes of actions, or suits of any kind or nature whatsoever, known or unknown, foreseen or unforeseen, that arose or could have arisen under the JOA for events that occurred prior to the date of the filing of this settlement." The settlement agreement also includes an agreement to perform a comprehensive and inclusive "Baseline Review" by an independent third party of all of the Midwest ISO's and PJM's existing means and processes for implementing the market-to-market provisions of the JOA, including those pertaining to market-to-market settlements. Also, the settlement includes additional provisions outlining a change management process, a biennial review of process changes, enhanced access to data, limitations on claims and resettlements under the JOA and amendments to the JOA to implement a set of guiding principles and modifications to certain market-to-market procedures that facilitate effective coordination and avoid future disputes.[30] The MMU remains concerned that this disagreement over administration of the JOA will unduly detract from its ability to serve as the basis for moving forward industry practice for managing congestion and loop flows at system interfaces, but notes that the *Memorandum of Understanding* signed by PJM and the Midwest ISO on May

28 See "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).

29 See 131 FERC ¶ 61,284 (June 29, 2010).

30 See "Explanatory Statement" Docket No. EL10-45-000; Docket No. EL10-46-000; Docket No. EL10-60-000 (Consolidated) (January 4, 2011).

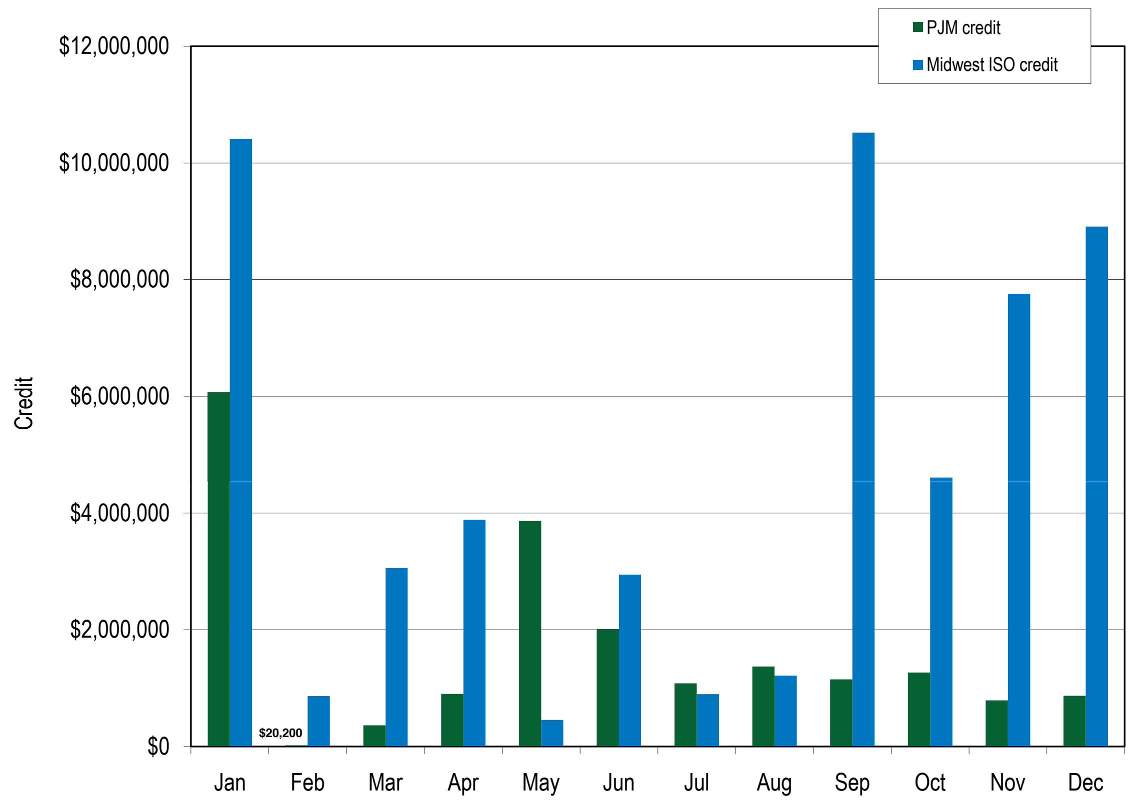
27, 2010 "reaffirms the value of the agreement and pledges continued cooperation to develop new practices to improve the interface between the two organizations."[31]

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 to eliminate payments between RTOs when such payments would 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 4-13 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 in 2010 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 in 2010 were approximately $55.5 million, a 22 percent increase from the 2009 level. The largest payments from the Midwest ISO to PJM in 2010 were the result of redispatch by PJM to relieve congestion on the Pleasant Prairie-Zion 345 kV for the loss of Zion-Arcadian 345 kV line. Total Midwest ISO payments to PJM were approximately $19.8 million, a 150 percent increase from the 2009 level.

31 See "PJM-MISO-MOU-May-2010" (May 27, 2010) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pjm-miso-mou-may-2010.ashx> (313 KB).

Figure 4-13 Credits for coordinated congestion management: Calendar year 2010



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 in 2010. 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 remained in effect through 2010. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[32] The MMU responded to the filing on February 23, 2010.[33] The MMU response noted that the agreement included discriminatory treatment for the identified transactions with respect to access to ATC, that a regional approach is preferable to entering into agreements with individual neighbors,

32 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010)
33 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010)

and that a sunset should be required in order to ensure that the next step towards such regional coordination is taken without delay. PJM and PEC filed an answer on March 10, 2010, to which the MMU responded on April 2, 2010. PJM and PEC filed an additional answer on April 19, 2010.[34] On May 28, 2010, the Commission conditionally approved the revised PJM/PEC JOA.[35] PJM and PEC were required to make a compliance filing within thirty days of the date of the order answering specific questions related to the impact of the scheduling arrangement on NERC standards and discriminatory access, the market pricing mechanisms with regards to eliminating the nuclear and hydro units from the calculation and the discriminatory use of export make whole payments under this agreement. On June 28, 2010, PJM and PEC filed their response.[36] The MMU responded to the compliance filing on July 19, 2010, reiterating the argument that the PJM/PEC JOA provides for preferential treatment to ATC and that the elimination of nuclear and hydro units from the interface price calculation is not consistent with the economics of locational marginal pricing.[37] The MMU moved for a technical conference to explore these issues.[38] On January 20, 2011, the commission conditionally accepted the compliance filing made by PJM and Carolina Power, stating that the proposed CMP was a just and reasonable solution to managing congestion between Regional Transmission Organizations (RTOs) and other systems. The acceptance of the JOA revisions is subject to the condition that PJM file a revised provision to its tariff that details how similarly situated parties can elect to use such a scheduled arrangement, including the after-the-fact transmission reservations provisions.[39]

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 2010.

Other Agreements/Protocols 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.[40] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the

34 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM; Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc., in Docket No. ER10-713-000.
35 See Docket No. ER10-713-000. Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Progress Energy Carolinas.
36 See "Compliance Filing," Docket No. ER10-713-002.
37 See " Comments and Motion for Technical Conference of the Independent Market Monitor for PJM," Docket No. ER10-713-002.
38 *Id.*
39 132 FERC ¶ 61,048 (2011).
40 111 FERC ¶ 61,228 (2005).

delivery performance in January 2006.[41] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[42] PJM continued to operate under the terms of the protocol through 2010.

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 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 2010, PSE&G's revenues were less than its congestion charges by $1,028,909 after adjustments ($5,417 in 2009.) 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 2010, Con Edison's congestion credits were $3,066,001 less than its day-ahead congestion charges (Credits had been $232,745 less than charges in 2009 (Table 4-9)).

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 -$178,749 in 2010. The parties should address this issue.

41 "Protest of the Consolidated Edison Company of New York, Inc.", Protest, Docket No. EL02-23-000 (January 30, 2006).

42 120 FERC ¶ 61,161

Table 4-9 Con Edison and PSE&G wheeling settlement data: Calendar year 2010

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$5,366,488	($23,991)	$5,342,497	$8,499,150	$0	$8,499,150
Congestion Credit			$2,300,487			$7,118,980
Adjustments			$18,050			$351,261
Net Charge			$3,023,960			$1,028,909

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 five percent of the hours in 2010.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[43] By order issued September 16, 2010, the Commission approved this settlement,[44] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[45]

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.

43 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

44 132 FERC ¶ 61,221.

45 *See*, *e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010). The MMU questioned whether allowing rollover is appropriate and raised concerns that continuing these agreements could interfere with the efficient management of the NYISO/PJM seam, accord preferential access to transmission service and limit security constrained least cost dispatch. The MMU questioned whether a valid offsetting reliability consideration had been identified and explained. The MMU noted, "the settling parties fail to demonstrate any circumstances that may now exist warranting a non-conforming agreement under the current approach to seams management, nor do they attempt to explain how such circumstances would continue to exist under the reforms to be implemented through the Broader Regional Markets Initiative." Additionally, that MMU argued, "the settling parties have failed to show that continuation of the grandfathered transmission service agreements will neither interfere with the efficient calculation of LMPs in both PJM and the NYISO, and at their interface, nor harm the ability of parties to efficiently transact business."

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 2010 as a whole, is not a useful measure of loop flow. There were significant differences between scheduled and actual flows for specific individual interfaces (Table 4-10). 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.

In 2010, for PJM as a whole, net scheduled and actual interchange differed by 5.2 percent (Table 4-10).[46] Actual system net exports were 6,425 GWh, 353 GWh more than the scheduled total net exports of 6,778 GWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 13,547 GWh exceeding scheduled imports of 1,559 GWh by 15,106 GWh or 969 percent, an average of 1,724 MW during each hour of the year. At the PJM/CPLE Interface, scheduled flows were exports of 421 GWh and actual flows were imports of 8,350 GWh, creating an imbalance of 8,771 GWh or 2,083 percent, an average of 1,001 MW during each hour of the year.

46 The the "Net Scheduled" values shown in Table 4-10 include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in this table does not match the interchange values shown in Figure 4-1,Figure 4-2 and Figure 4-3, and Table 4-1 through Table 4-6.

Table 4-10 Net scheduled and actual PJM interface flows (GWh): Calendar year 2010

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	8,350	(421)	8,771	(2,083%)
CPLW	(1,907)	0	(1,907)	0%
DUK	(2,975)	(48)	(2,927)	6,098%
EKPC	1,021	(176)	1,197	(680%)
LGEE	1,300	1,754	(454)	(26%)
MEC	(2,682)	(5,172)	2,490	(48%)
MISO	(7,920)	(268)	(7,652)	2,855%
ALTE	(5,974)	(591)	(5,383)	911%
ALTW	(2,279)	(646)	(1,633)	253%
AMIL	7,260	(315)	7,575	(2,405%)
CIN	1,923	3,503	(1,580)	(45%)
CWLP	(314)	(22)	(292)	1,327%
FE	(272)	(2,297)	2,025	(88%)
IPL	2,490	(438)	2,928	(668%)
MECS	(13,547)	1,559	(15,106)	(969%)
NIPS	(2,716)	(498)	(2,218)	445%
WEC	5,509	(523)	6,032	(1,153%)
NYISO	(12,305)	(13,590)	1,285	(9%)
LIND	(1,218)	(1,218)	0	0%
NEPT	(4,767)	(4,767)	0	0%
NYIS	(6,320)	(7,605)	1,285	(17%)
OVEC	7,381	11,846	(4,465)	(38%)
TVA	3,312	(703)	4,015	(571%)
Total	(6,425)	(6,778)	353	(5.2%)

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

As it had in 2009, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-15,106 GWh in 2010 and -14,441 GWh in 2009), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (4,015 GWh in 2010 and 3,840 GWh in 2009). 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 4-14 and Figure 4-15 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 the real-time LMP at the Southeast pricing points and the SouthEXP pricing point was $4.32 in 2010 and the average difference between the real-time LMP at the Southwest pricing points and the SouthEXP pricing point was -$2.87 in 2010. 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 grandfathered 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 4-14 and Figure 4-15 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 prices with physical flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) 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 SPP, 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 SPP 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 4-14 Southwest actual and scheduled flows: January 2006 through December 2010

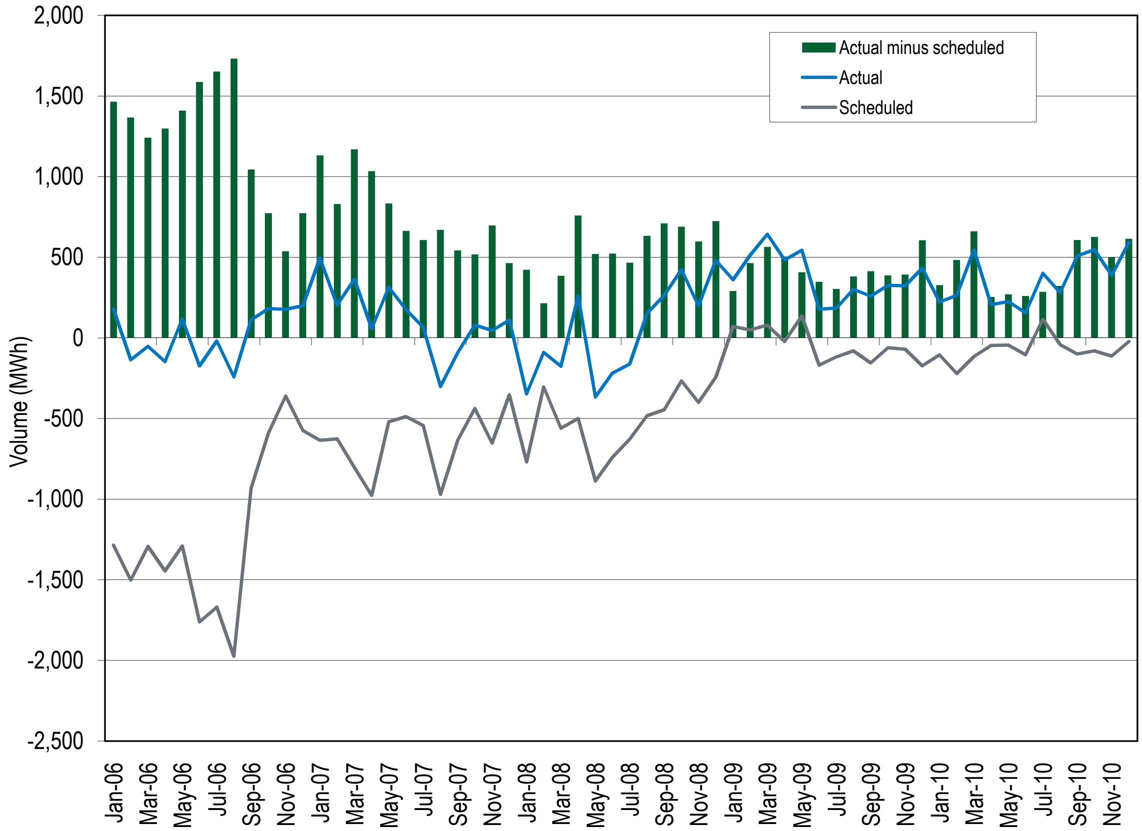
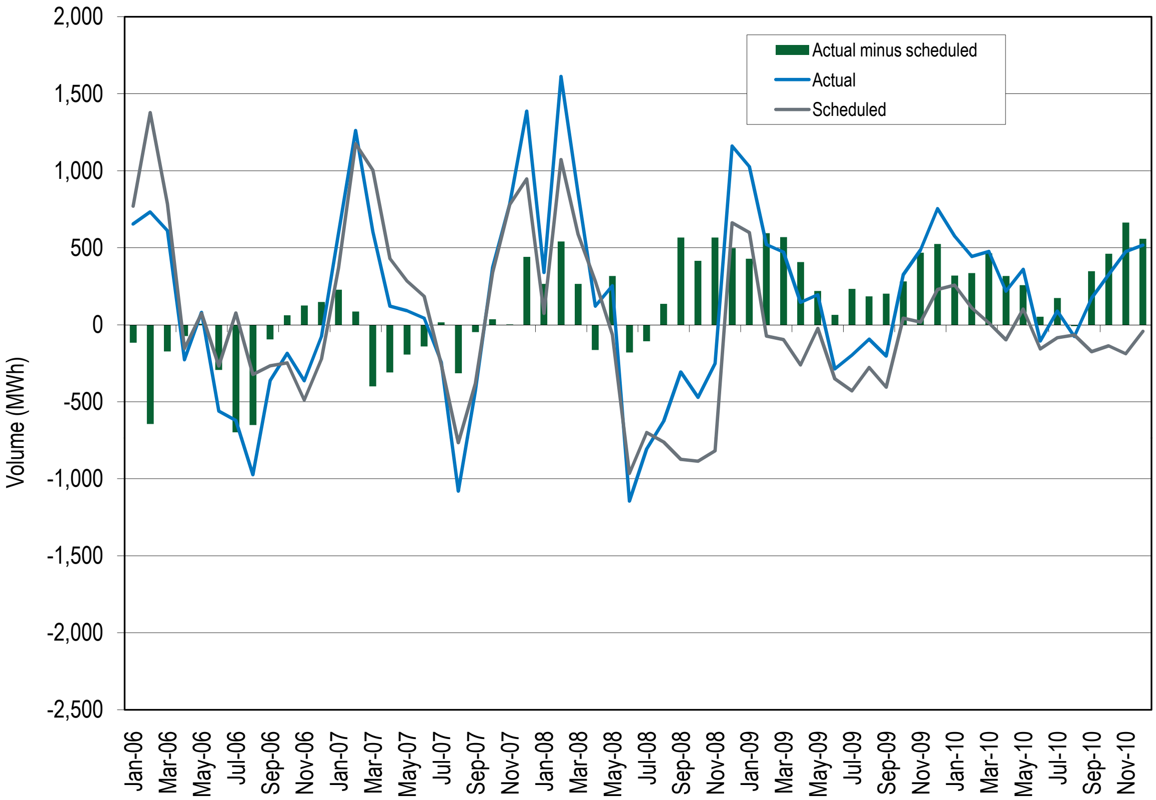


Figure 4-15 Southeast actual and scheduled flows: January 2006 through December 2010



Loop Flows at PJM's Northern Interfaces

In 2008, new loop flows were created when NYISO pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows.[47] 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."[48]

47 See the *2008 State of the Market Report for PJM*, Volume II, "Interchange Transactions."
48 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

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.[49]

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. After working in collaboration with PJM, the Midwest ISO and the Ontario Independent Electricity System Operator (IESO), including an opportunity to comment by 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.[50]

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 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 nine 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.

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.

On July 15, 2010, the Commission conditionally accepted the NYISO Report subject to the parties filing answers to the questions set forth in the order within 30 days of the date of the order.[51]

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

50 See "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (January 12, 2010).

51 132 FERC ¶ 61,031.

The Commission requested that the parties provide additional evidence regarding the proposed solutions. On August 16, 2010, the NYISO provided their response to the July 15th Order.[52] On September 15, 2010, the PJM Market Monitoring Unit (MMU) responded to the NYISO filing.[53] The MMU commented that the NYISO response lacked detail and focus in implementing solutions that could be implemented quickly, and continued to lack detailed and firm timelines for implementation. Additionally, the MMU questioned the curtailment priority granted to transactions scheduled on non-firm transmission when electing to purchase "buy-through of congestion" as well as the inability to implement a market to market congestion management agreement with PJM. Finally, the MMU provided comments and recommendations on implementing an interface pricing solution and a market to market Congestion Management Protocol (CMP) in the NYISO to mitigate the incentives to scheduling circuitous paths into and out of the NYISO. The MMU also actively participated in the meeting of the Broader Regional Markets Group in Philadelphia on September 27, 2010, and continues to advocate in that process a joint operating agreement between NYISO and PJM that is equivalent to or better than the JOA between the Midwest ISO and PJM. On December 30, 2010, the Commission issued an Order on Rehearing and Compliance which indicated that they agreed with the MMU comments and directed the NYISO to make interface pricing revisions by the second quarter of 2011. Additionally, the Commission required that congestion management/market-to-market coordination for the Commission-jurisdictional RTO/ISOs be completed concurrently by the second quarter of 2011.[54]

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 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 5.2 percent in 2010, 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.

52 See "Response to Questions and Supplemental Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (August 16, 2010).
53 See "Comments of the Independent Market Monitor for PJM."Docket No. ER08-1281-004 (September 15, 2010).
54 133 FERC ¶ 61,276.

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. 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 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.

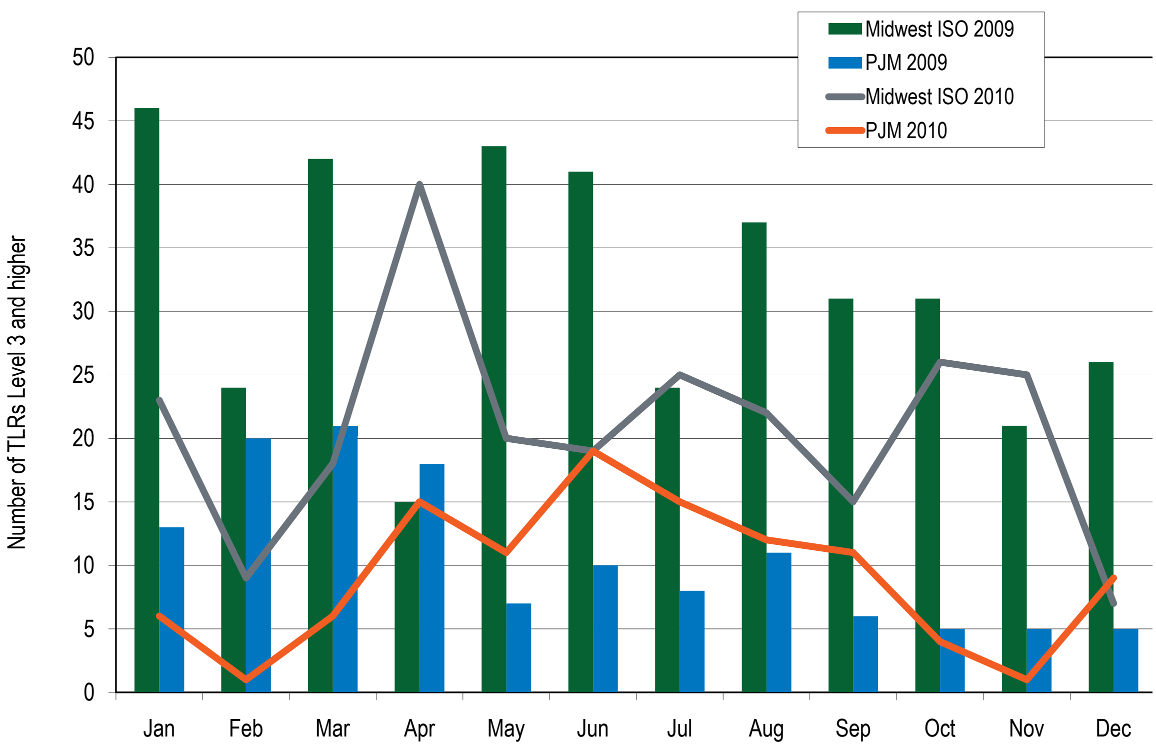
PJM called fewer TLRs in 2010 than in 2009. The fact that PJM has issued only 110 TLRs in 2010, compared to 129 in 2009, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with the Midwest ISO. PJM TLRs decreased by 15 percent, from 129 during 2009 to 110 in 2010 (Figure 4-16). In addition, the number of different flowgates for which PJM declared TLRs decreased from 28 in 2009 to 25 in 2010 (Figure 4-17). The total MWh of transaction curtailments decreased by 67 percent, from 912,528 MWh in 2009 to 298,488 MWh in 2010 (Figure 4-18). Of the 110 TLRs called by PJM in 2010, two facilities comprised 35 percent of the total. The two facilities were:

- **2419 Danville – E Danville 138 kV line for the loss of Jacksons Ferry – Antioch 500 kV line.** This line is located in southern Virginia.[55] TLRs were used to control the constraints (22 TLRs in 2010; 3 TLRs in 2009);

- **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 2010. TLRs on this flowgate were used to control the constraints (16 TLRs in 2010; 28 TLRs in 2009).

The Midwest ISO called significantly fewer TLRs in 2010 than in 2009. The Midwest ISO TLRs decreased by 35 percent, from 381 in 2009 to 249 in 2010 (Figure 4-16).

Figure 4-16 PJM and Midwest ISO TLR procedures: Calendar years 2009 and 2010



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

Figure 4-17 Number of different PJM flowgates that experienced TLRs: Calendar years 2009 and 2010

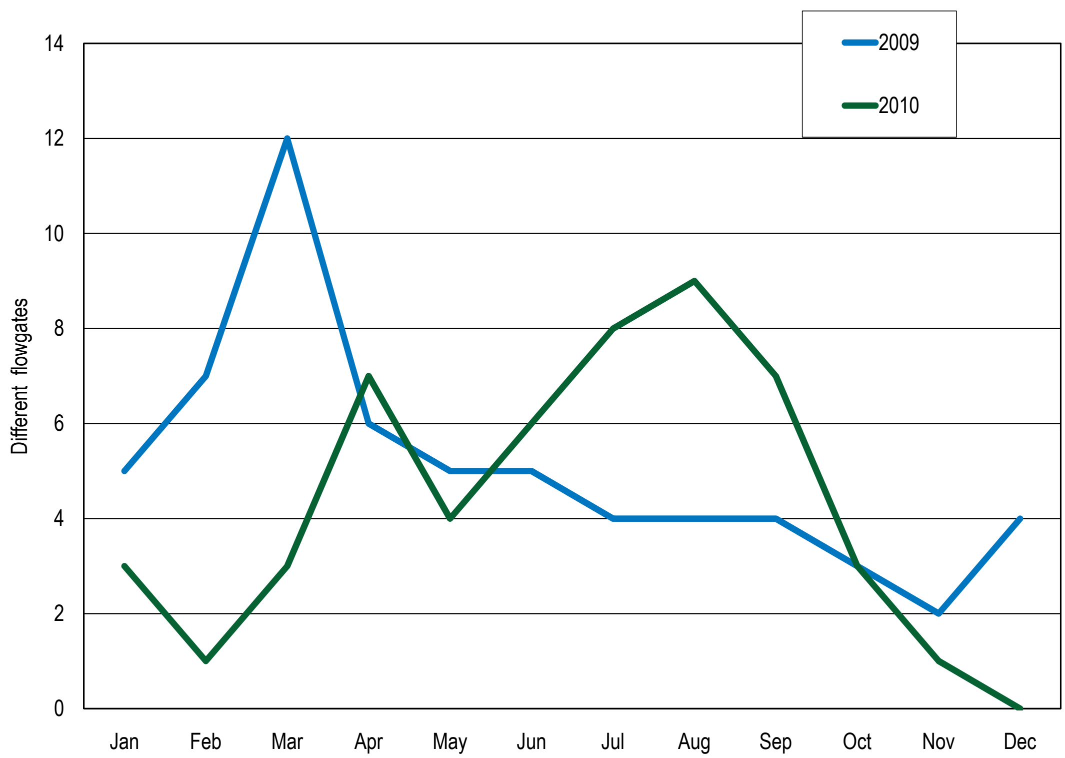


Figure 4-18 Number of PJM TLRs and curtailed volume: Calendar year 2010

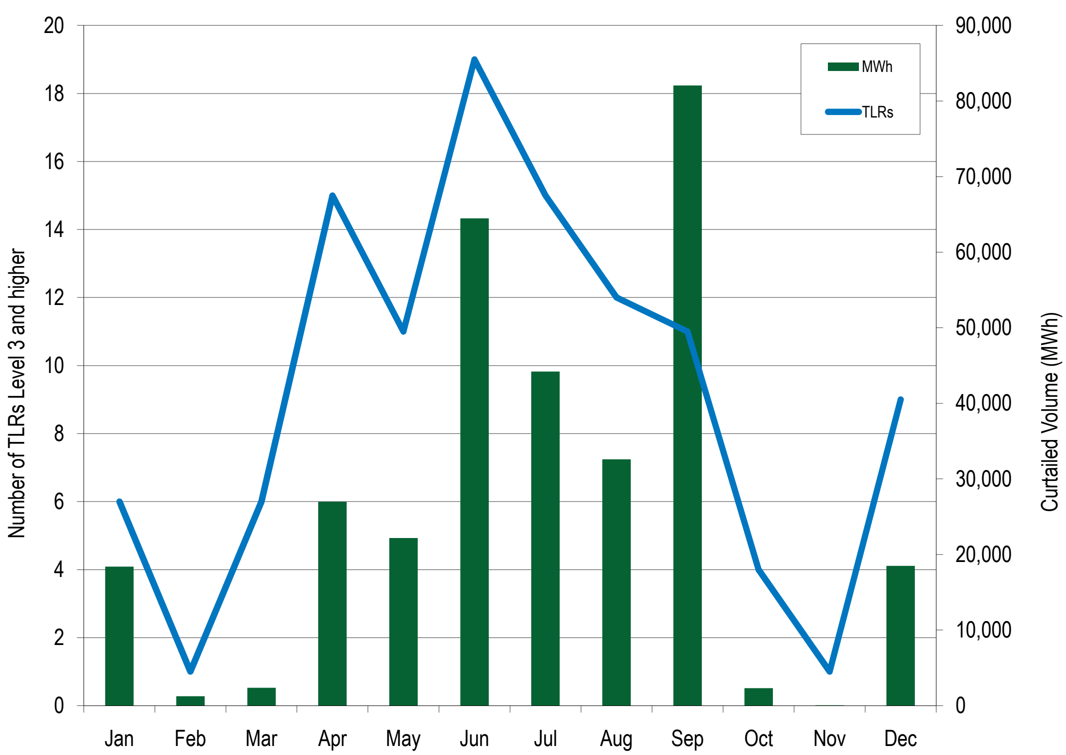


Table 4-11 shows the number of TLRs by TLR level for each reliability coordinator in the Eastern Interconnection. The TLR levels are defined in Appendix E "Interchange Transactions" of this document. In 2010, PJM issued 110 transmission loading relief procedures (TLRs). Of the 110 TLRs issued, the highest levels reached were TLR 3a in 65 instances and TLR 3b in the remaining 45 events (2009 totals were 61 TLR 3a, 68 TLR 3b, 0 TLR 4 and 0 TLR 5b).

Table 4-11 Number of TLRs by TLR level by reliability coordinator: Calendar Year 2010

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2010	ICTE	72	25	149	50	30	0	326
	MISO	123	93	0	15	18	0	249
	NYIS	104	0	0	0	0	0	104
	ONT	94	5	0	1	0	0	100
	PJM	65	45	0	0	0	0	110
	SWPP	244	1,049	19	63	32	0	1,407
	TVA	37	64	8	1	6	0	116
	VACS	1	1	0	0	0	0	2
Total		740	1,282	176	130	86	0	2,414

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 Energy 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 Energy 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 Energy Market if the maximum congestion bid criteria is met, and is not subject to day-ahead or balancing operating reserve chargIn 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 Energy Market and real-time transactions.[56] 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.[57] 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 Energy Market scheduling.

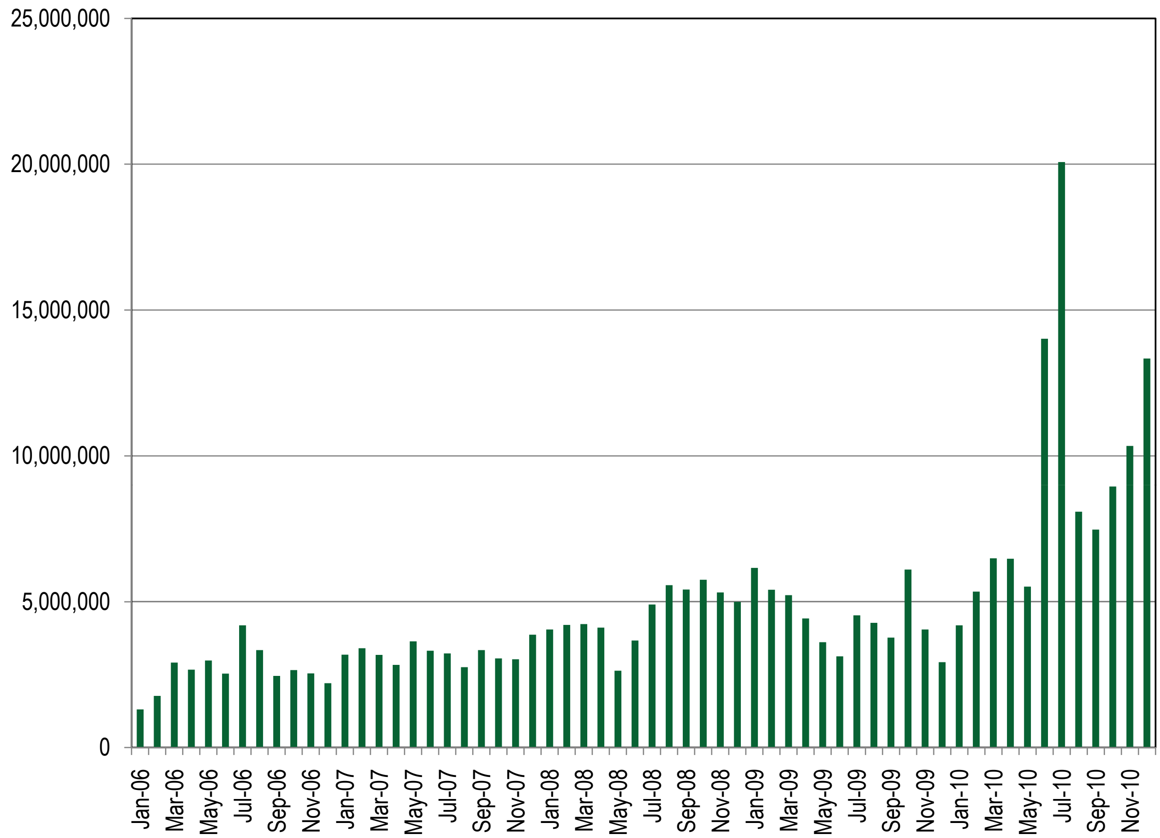
In the period following the March 1, 2008 modifications to the up-to congestion bids, through December 31, 2010, the monthly average of up-to congestion bidding increased from 3,027.1 GWh to 6,192.9 GWh. In June and July of 2010, there was a significant increase in the total up-to congestion bids as shown in Figure 4-19. This increase in activity for up-to congestion transactions was caused by the allocation methodology for the marginal loss surplus.

As a result of modifications to the marginal loss surplus allocation, the up-to congestion product was modified such that the requirement for up-to congestion transactions to obtain transmission service was eliminated. In order to minimize the effects of eliminating the transmission requirement for up-to congestion transactions, PJM created a new product on the OASIS, called "Up-to Congestion". Market participants are still required to access the PJM OASIS and obtain an "up-to congestion" reservation. However, the product is not limited by ATC, nor is there a charge associated with the product. The sole purpose of this product is to allow market participants to specify specific sources and sinks for which up-to congestion transactions will be evaluated in the Day-Ahead Market.

56 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).

57 See "Minutes of the Twenty-First Meeting" Minutes from PJM's MRC Meeting (February 21, 2008) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221/20080221-minutes.ashx> (61KB).

Figure 4-19 Monthly up-to congestion bids in MWh: January 2006 through December 2010



The up-to congestion transactions in 2010 were comprised of 49.9 percent imports, 44.5 percent exports and 5.6 percent wheeling transactions (Table 4-12). Only 0.1 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions. Of the up-to congestion transactions with matching Real-Time Energy Market transactions, 4.0 percent were imports, 84.9 percent were exports and 11.1 percent were wheel through transactions.

Table 4-12 Up-to congestion MW by Import, Export and Wheels: Calendar years 2006 through 2010

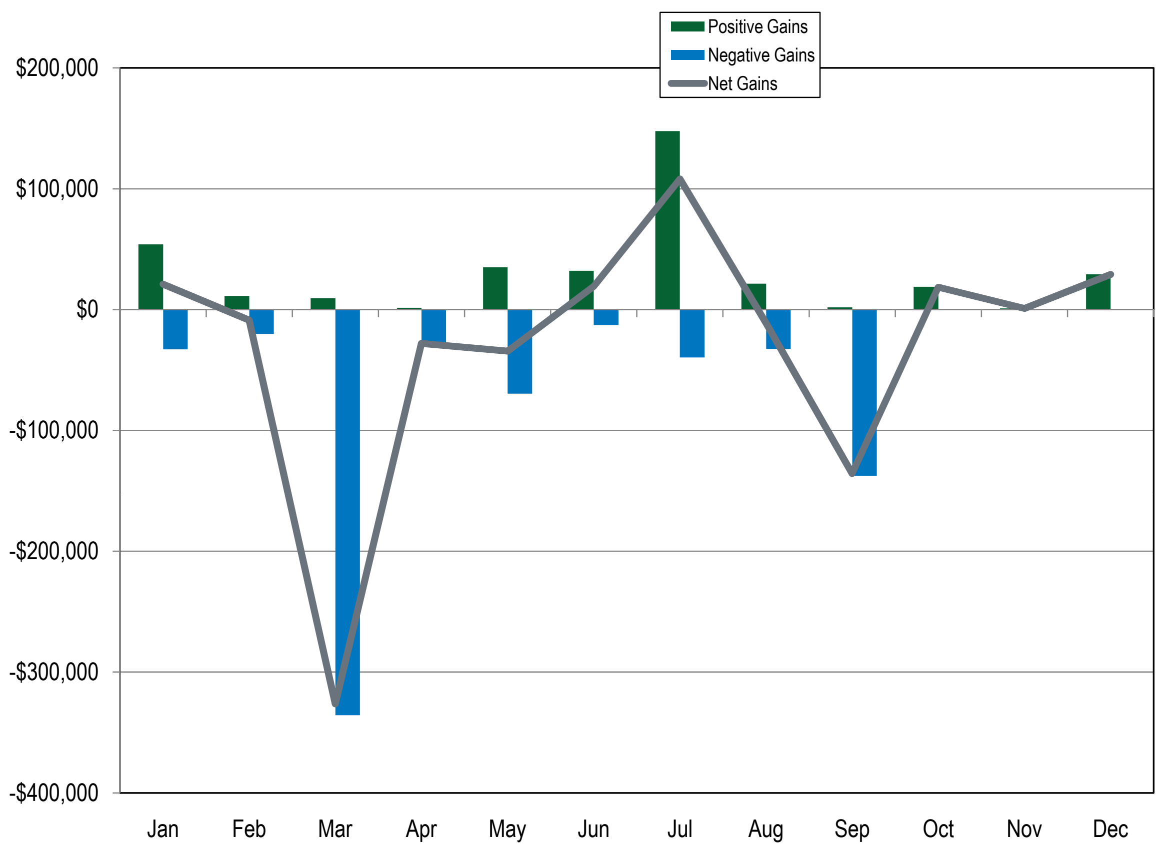
	Import MW	Export MW	Wheeling MW	Total MW	Percent Imports	Percent Exports	Percent Wheels
2006	10,730,659	20,398,833	468,648	31,598,141	34.0%	64.6%	1.5%
2007	13,950,514	24,080,803	817,237	38,848,554	35.9%	62.0%	2.1%
2008	20,889,972	32,351,960	1,632,874	54,874,806	38.1%	59.0%	3.0%
2009	24,455,358	27,722,740	1,453,553	53,631,651	45.6%	51.7%	2.7%
2010	55,052,156	49,064,283	6,192,876	110,309,315	49.9%	44.5%	5.6%
TOTAL	125,078,659	153,618,620	10,565,187	289,262,466	43.2%	53.1%	3.7%

Market participants have the opportunity to match the source and sink between the Day-Ahead and Real-Time Energy Markets, but they have not done so. An analysis of the up-to congestion data shows that submitted Real-Time Energy Market transactions match the submitted Day-Ahead Energy Market up-to congestion bid only 0.1 percent of the time. For 99.9 percent of the time, submitted Real-Time Energy Market transactions do not match the submitted Day-Ahead Energy Market up-to congestion bids being made by participants.

When the up-to congestion product was used as intended, with matching Real-Time Energy Market transactions, 29.5 percent of such cleared transaction MW were profitable in 2010. The net loss on all these transactions was approximately $347,000. When up-to congestion transactions did not have a matching Real-Time Energy Market transaction, 43.7 percent of such cleared transaction MW were profitable. The net profit on all these transactions was approximately $64.6 million.[58]

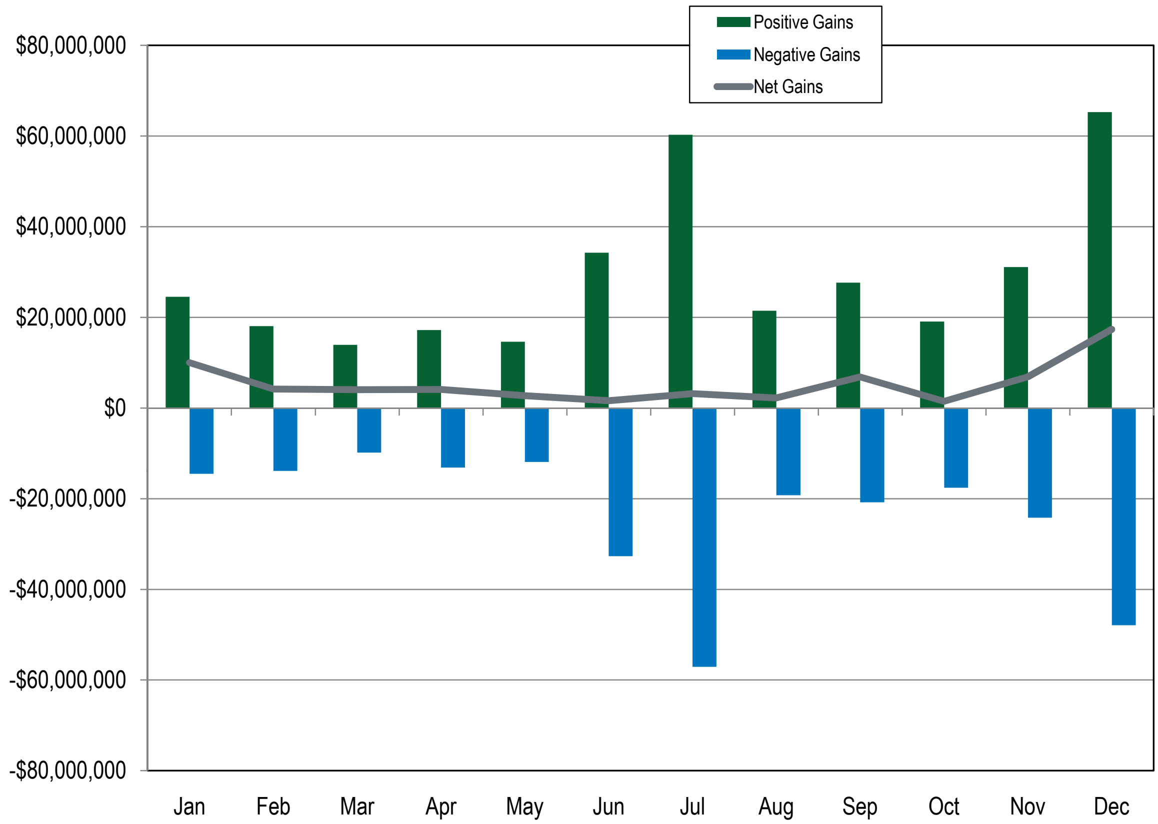
Figure 4-20 and Figure 4-21 show the monthly positive, negative and net gains for matching and non-matching up-to congestion transactions. Figure 4-20 shows the matching transactions on a different scale than Figure 4-21. There is such a small number of matching transactions that the results would not be visible on the scale of Figure 4-21.

Figure 4-20 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction: Calendar year 2010



58 The total profitability results for up-to congestion transactions reported in the 2009 State of the Market Report for PJM and the first three quarterly 2010 State of the Market Reports for PJM were incorrect.

Figure 4-21 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Energy Market transaction: Calendar year 2010



Of all the market participants that utilize up-to congestion transactions, the top five participants accounted for 41 percent of all transactions and the top ten participants accounted for 58 percent of all transactions. The top five participants that experienced losses accounted for 91 percent of all the losses, and the top ten participants accounted for 99 percent of all the losses on those bids.

The MMU recommends that the up-to congestion transaction product be eliminated. Alternatively, 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 Energy 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 Balancing Authorities

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.[59] Table 4-13 shows the historical differences in Real-Time Energy Market 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 4-13 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through December 2010

	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)
2010	$43.46	$36.27	$39.29	$39.14	$4.17	($3.02)	$4.32	($2.87)

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;[60] Progress Energy Carolinas, February 13, 2007;[61] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[62] 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.

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

59 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).
60 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).
61 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).
62 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).

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).[63] 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[64], and approved on May 1, 2009.[65] 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 beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[66] As of December 31, 2009, Duke Energy Carolinas and Progress Energy Carolinas were in the process of negotiating a congestion management agreement with PJM.

63 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).
64 See Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008).
65 See, Letter Order, Docket No. ER09-369-000 (May 1, 2009).
66 127 FERC ¶ 61,101.

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 4-14 through Table 4-16 show the real-time and a day-ahead prices for imports and exports applicable for the interface pricing under the various agreements.

In September 2009, Progress Energy Carolinas provided an update to the PJM Market Implementation Committee (MIC) on the proposed congestion management agreement.[67] 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 and PEC filed a revision to the JOA to include a CMP.[68] The MMU responded to the filing on February 23, 2010.[69] The MMU response noted that the agreement included discriminatory treatment for the identified transactions with respect to access to ATC, that a regional approach is preferable to entering into agreements with individual neighbors, and that a sunset should be required in order to ensure that the next step towards such regional coordination is taken without delay. PJM and PEC filed an answer on March 10, 2010, to which the MMU responded on April 2, 2010. PJM and PEC filed an additional answer on April 19, 2010.[70] On May 28, 2010, the Commission conditionally approved the revised PJM/PEC JOA.[71] PJM and PEC were required to make a compliance filing within thirty days of the date of the order answering specific questions related to the impact of the scheduling arrangement on NERC standards and discriminatory access, the market pricing mechanisms with regards to eliminating the nuclear and hydro units from the calculation and the discriminatory use of export make whole payments under this agreement. On June 28, 2010, PJM and PEC filed their response.[72] The MMU responded to the compliance filing on July 19, 2010, reiterating the argument that the PJM/PEC JOA provides for preferential treatment to ATC and that the elimination of nuclear and hydro units from the interface price calculation is not consistent with the economics of locational marginal pricing.[73] The MMU moved for a technical conference to explore these issues.[74] As of December 31, 2010, the Commission had not made any additional issuances related to the Compliance Filing or the comments submitted by the MMU.

Table 4-14 shows the real-time LMP calculated per the revised agreements made effective on May 3, 2009 for the calendar year 2010. The difference between the LMP under this agreement and PJM's SouthIMP LMP ranged from $1.83 with Duke to $2.71 with PEC.[75] The difference between the LMP under this agreement and PJM's SouthEXP LMP ranged from $2.73 with NCMPA to $5.89 with PEC.

67 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)
68 See Docket No. ER10-713-000 (February 2, 2010).
69 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010).
70 See Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM; Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc., in Docket No. ER10-713-000.
71 See Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Progress Energy Carolinas. Docket No. ER10-713-000.
72 See "Compliance filing ", Docket No. ER10-713-002.
73 See "Comment and Motion for Technical Conference of the Independent Market Monitor for PJM," Docket No. ER10-713-002.
74 *Id.*
75 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

Table 4-14 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2010

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.12	$42.29	$39.29	$39.14	$1.83	$3.14
PEC	$42.01	$45.04	$39.29	$39.14	$2.71	$5.89
NCMPA	$41.71	$41.87	$39.29	$39.14	$2.42	$2.73

Figure 4-22 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2010

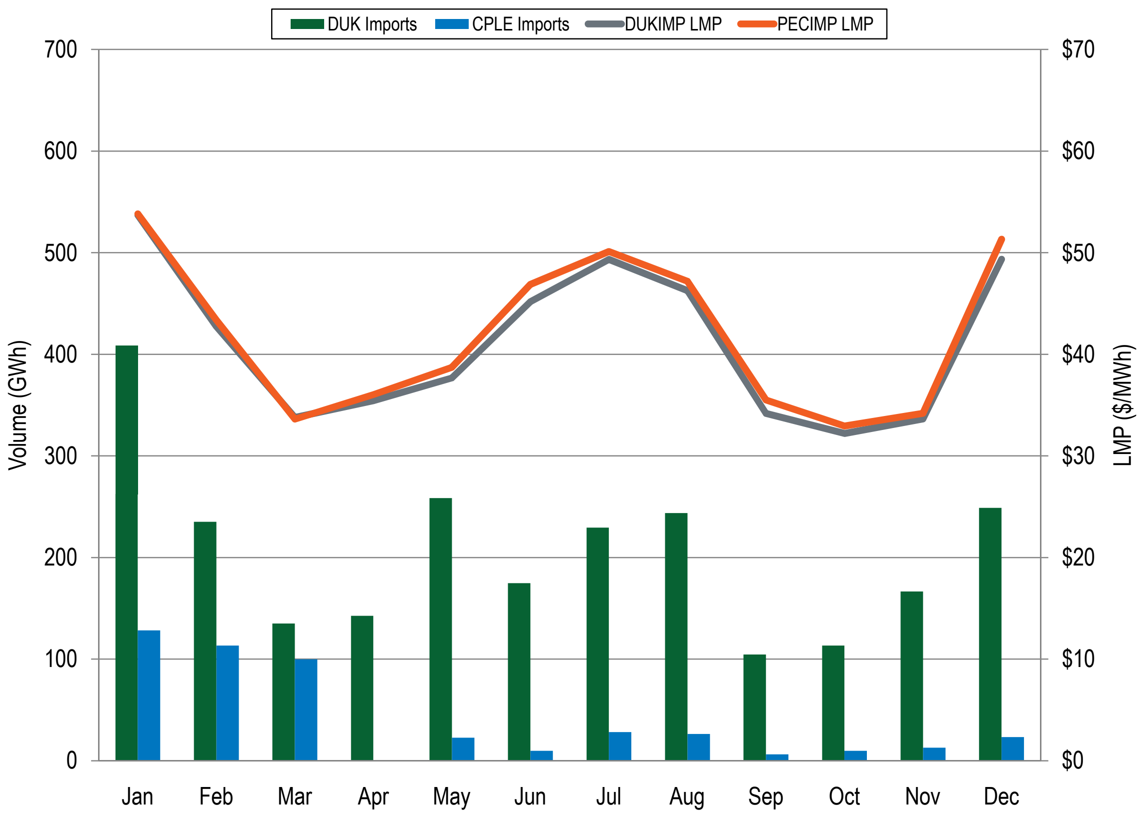


Figure 4-23 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2010

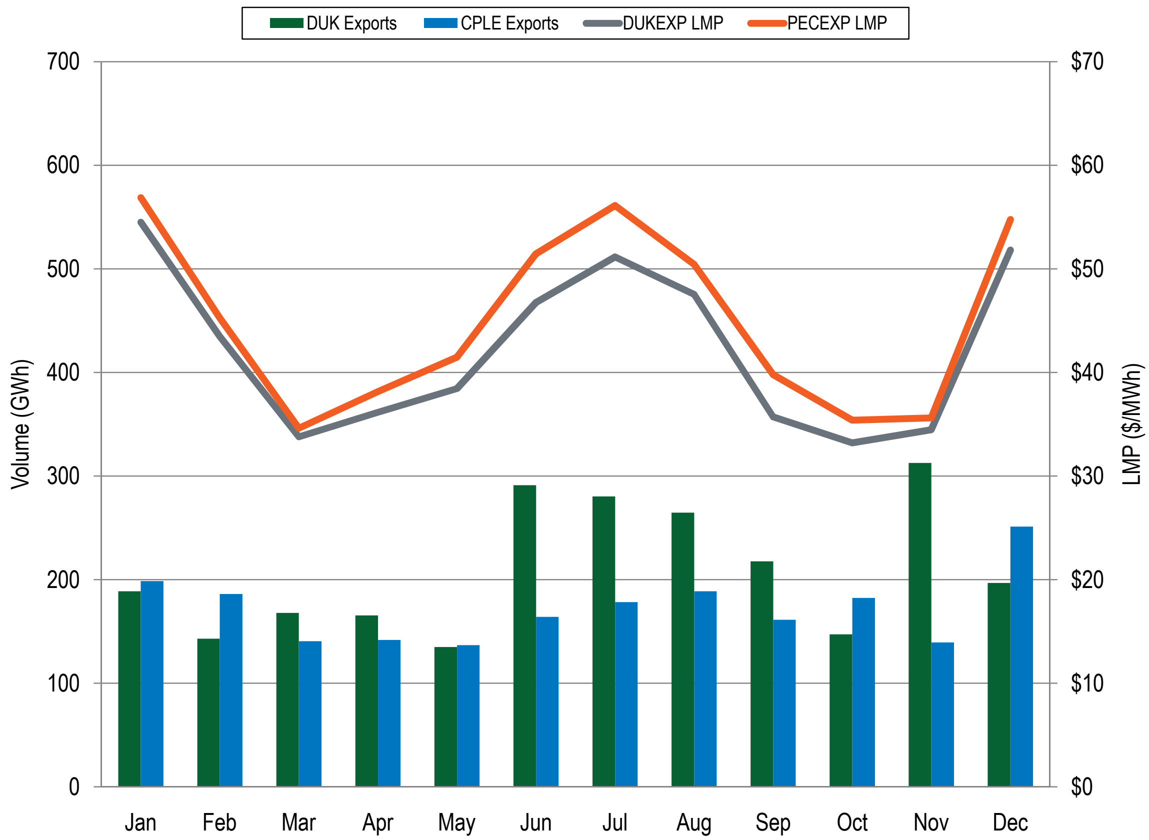


Table 4-15 shows the historical differences in Day-Ahead Energy Market LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation. The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, 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 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through December 2010

	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	$41.53	$38.10	$38.32	$41.23	$3.21	($0.22)	$0.31	($3.13)
2007	$53.50	$45.01	$48.45	$47.76	$5.06	($3.44)	$5.75	($2.75)
2008	$63.44	$52.27	$56.26	$56.26	$7.17	($3.99)	$7.17	($3.99)
2009	$36.42	$32.05	$33.59	$33.59	$2.83	($1.54)	$2.83	($1.54)
2010	$44.42	$36.76	$39.40	$39.40	$4.64	($2.44)	$4.64	($2.44)

Table 4-16 shows the day-ahead LMP calculated per the revised agreements made effective on May 3, 2009 for the calendar year 2010. 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 LMP ranged from $2.05 with Duke to $3.36 with PEC. The difference between the LMP under this agreement and PJM's SouthEXP LMP ranged from $3.05 with NCMPA to $6.21 with PEC.

Table 4-16 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2010

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.45	$43.04	$39.40	$39.40	$2.05	$3.65
PEC	$42.75	$45.60	$39.40	$39.40	$3.36	$6.21
NCMPA	$42.30	$42.45	$39.40	$39.40	$2.91	$3.05

Figure 4-24 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2010

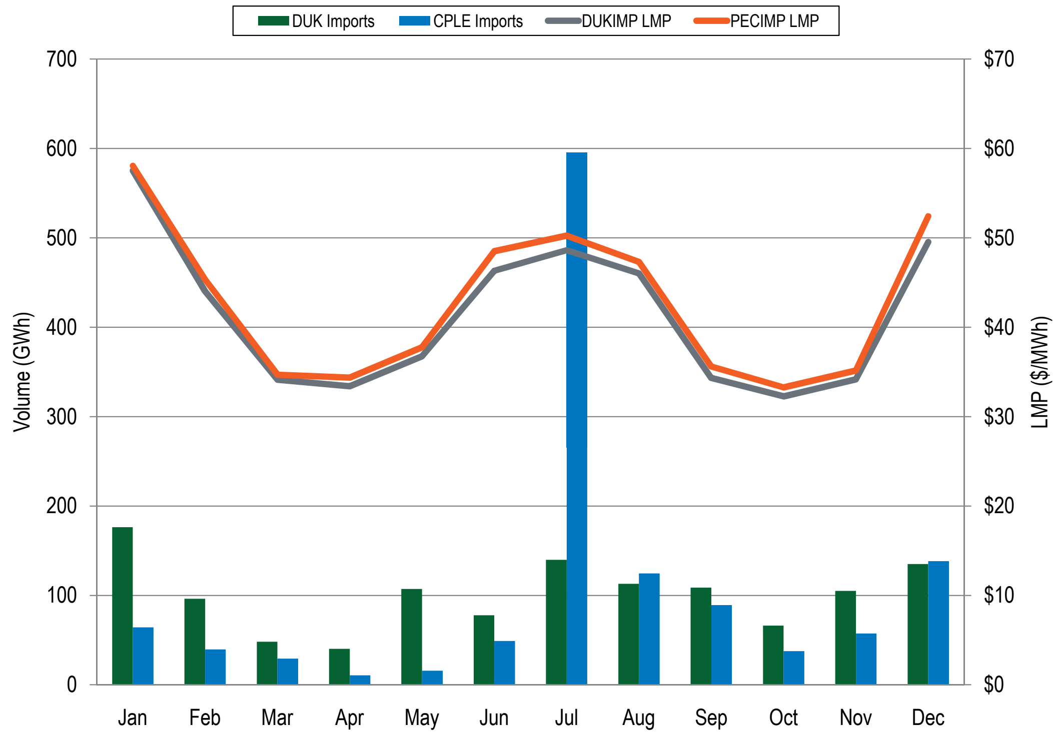
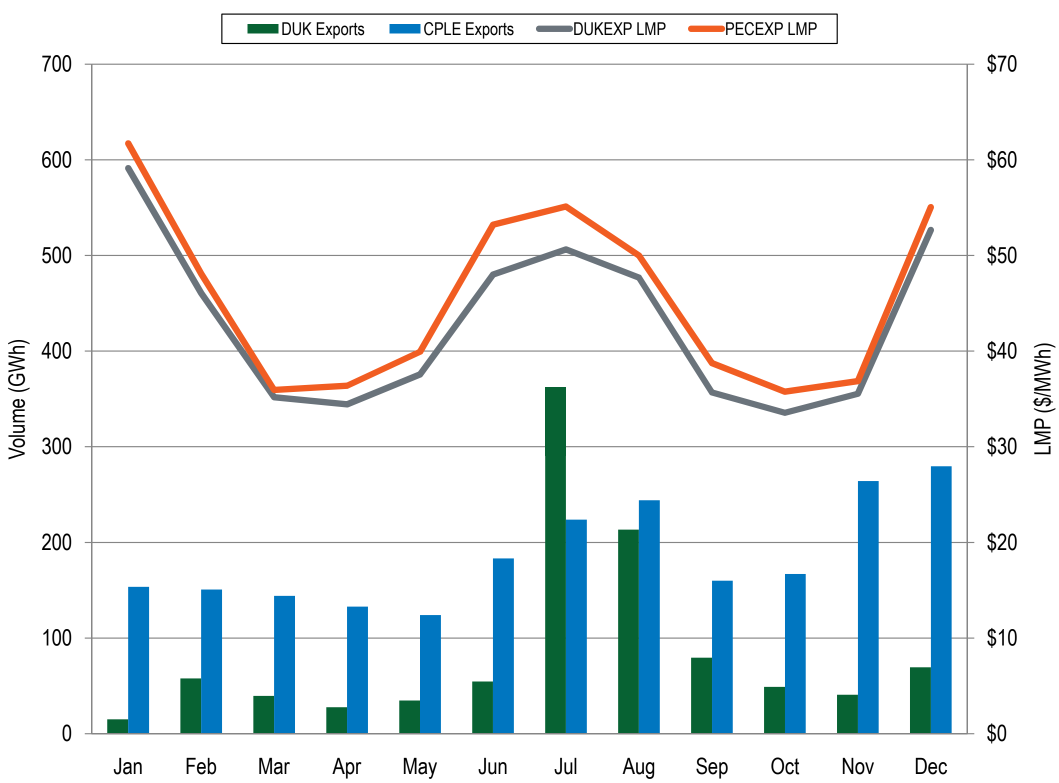


Figure 4-25 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2010



Marginal Loss Surplus Allocation

In an order on complaint, the Commission required PJM to correct an inconsistency in the tariff language defining the method for allocating the marginal loss surplus based on contributions to the fixed costs of the transmission system.[76] On May 15, 2010, PJM implemented the modified method of allocating the marginal loss surplus. As modified, Section 5.5 of the PJM OATT provided that a cleared up-to congestion transaction in the Day-Ahead Energy Market qualified for an allocation of the marginal loss surplus for an hour if that transaction required the purchase of transmission service. Prior to the modification, up-to congestion transactions had not been eligible for an allocation of the marginal loss surplus. However, PJM's tariff modification resulted in an allocation of the marginal loss surplus based on usage of the system rather than based on the dollar contribution to the fixed costs of the transmission system. The inconsistency between the allocation principle defined by FERC and the actual allocation created an incentive for market participants to enter noneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus. These transactions included the submission of up-to congestion wheeling transactions at the same interface, submission of equal and opposite up-to congestion transactions to and from the same internal PJM bus and equal and opposite up-to congestion transactions at buses within the PJM Energy Market that are physically close to one another where the LMP between those buses would be negligible. Market participants engaging in these activities received $18.1 million in marginal loss surplus allocations (with a net profit of $9.6 million after the cost of transmission) during the period of May 15, 2010, through August 31, 2010.

As a result of this activity, PJM and the MMU presented and discussed proposed short term revisions to the market rules at the August 5, 2010, meeting of the Markets and Reliability Committee and the August 12, 2010, meeting of the Members Committee.[77] PJM proposed to eliminate the requirement for up-to congestion transactions to obtain transmission service and to discount the marginal loss allocation to non-firm transmission service customers. The MMU short term proposal was to cap the marginal loss distribution to any non-firm transmission customer so that the allocations do not exceed the total charges for transmission service. PJM stakeholders voted in favor of the PJM proposal at the August 12, 2010 PJM Members Committee, subject to an agreement to initiate additional stakeholder discussions on a long term solution to the issues.[78]

The underlying problem, the inconsistency between the approved principle and the actual implementation of the method of allocating the marginal loss surplus has not yet been addressed.[79] In addition, PJM's proposal created a spread bidding product without explicit consideration by market participants. The MMU opposed spread bidding because it risked creating opportunities for gaming with no offsetting market benefit. While limited to either source or sink at an interface, the newly created spread bidding product raises the same issues previously identified with the spread bid product proposals that had been rejected by the PJM membership. On September 17, 2010, the Commission approved the PJM revisions as filed on August 18, 2010.[80] The Order deferred consideration of the issues raised by the MMU.

76 See 131 FERC ¶ 61,024 (2010) (order denying rehearing and accepting compliance filing); 126 FERC ¶ 61,164 (2009) (Order on request for clarification).

77 A copy of the presentations can be viewed at http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-11-marginal-loss-allocation-issue-monitoring-analytics-presentation.ashx and http://www.pjm.com/~/media/committees-groups/committees/mrc/20100805/20100805-item-11-marginal-loss-allocation-issue-pjm-presentation.ashx.

78 See "Amended and Restated Operating Agreement", Docket No. ER10-2280-000.

79 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM." Docket No. ER10-2280-000 (September 2, 2010).

80 See 132 FERC ¶ 61,244.

Willing to Pay Congestion and Not Willing to Pay Congestion

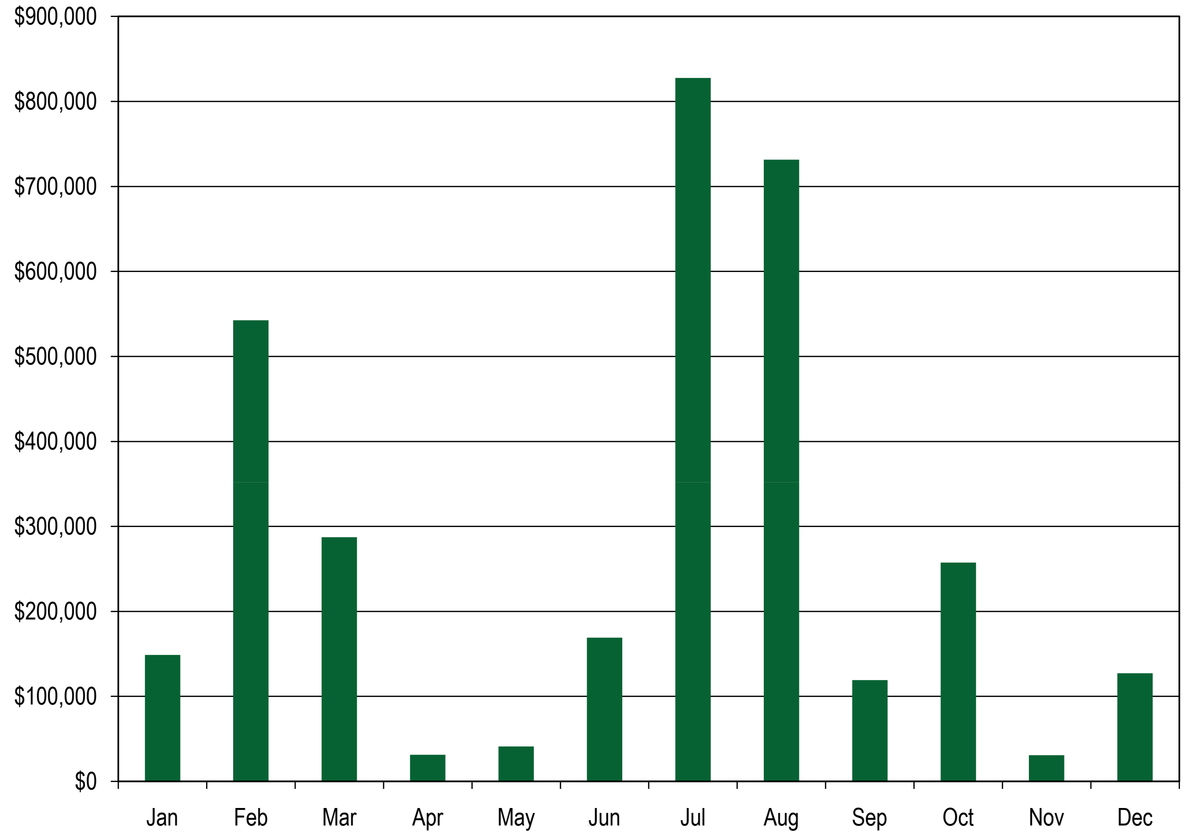
When reserving non-firm transmission, the market participant has the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary, to allow the energy transaction to continue to flow. The system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

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 total uncollected congestion charges for 2010 were approximately $3.3 million, which was an increase of 379 percent from the 2009 total of $688,547 (Figure 4-26). The increase in uncollected congestion charges was the result of an increase in market participant use of not willing to pay congestion transmission on their energy transactions in 2010.

The MMU recommended 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. On August 16, 2010, PJM modified the EES application to automatically detect and modify not willing to pay congestion transactions, prior to their start, when system LMPs at the transactions' identified source and sink differ. This functionality prevents not willing to pay congestion transactions from starting in those instances by automatically issuing curtailment requests. The same evaluation is performed on not willing to pay congestion transactions that have already been loaded, and will curtail those transactions at the next applicable 15 minute interval. These changes reduce the amount of uncollected congestion charges by eliminating the previously utilized manual intervention for curtailments and reducing the potential for not willing to pay congestion transactions to continue to flow, undetected. While the recent EES modifications automate the process for identifying those instances, the timing requirements for curtailing transactions requires that the evaluation be done with 20 minutes notice prior to the start of the transaction. There is still the potential for not willing to pay congestion transactions to begin in cases when congestion exists prior to the transaction start time but after the evaluation. When this occurs, the transaction will be curtailed at the next applicable 15 minute interval.

The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to be submitted at an interface, eliminating internal source and sink designations, thus allowing not willing to pay congestion transactions to be only submitted as wheeling transactions across the PJM footprint. At the January 11, 2011 meeting of the Market Implementation Committee (MIC) meeting, PJM stakeholders approved the changes recommended by the MMU. These modifications are currently being evaluated to determine if tariff or operating agreement changes are necessary prior to implementation.

Figure 4-26 Monthly uncollected congestion charges: Calendar year 2010



Elimination of Sources and Sinks

The MMU has recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch.

Until the internal source and sink designations are eliminated from the external energy transactions in the Day-Ahead Energy Market, the MMU continues to recommend that PJM require that all import and export up-to congestion transactions 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 reserve charges.

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. 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, were the only limits on interchange.

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.[81] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result, requests for service sometimes exceeded the amount of service available to customers. Spot import service (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.[82] 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 (defined as scheduling) has been over 99 percent, compared to 70 percent prior to the modification (Figure 4-27).

Although the rule change resulted in an increase in scheduling, some participants were still able to schedule but not use spot import service. In 2010, market participants were still unable to acquire spot import service on the NYIS-PJM path when it was not being used to flow energy. The MMU found that the bidding process in the NYISO resulted in market participants reserving and scheduling but not using transmission to flow energy.

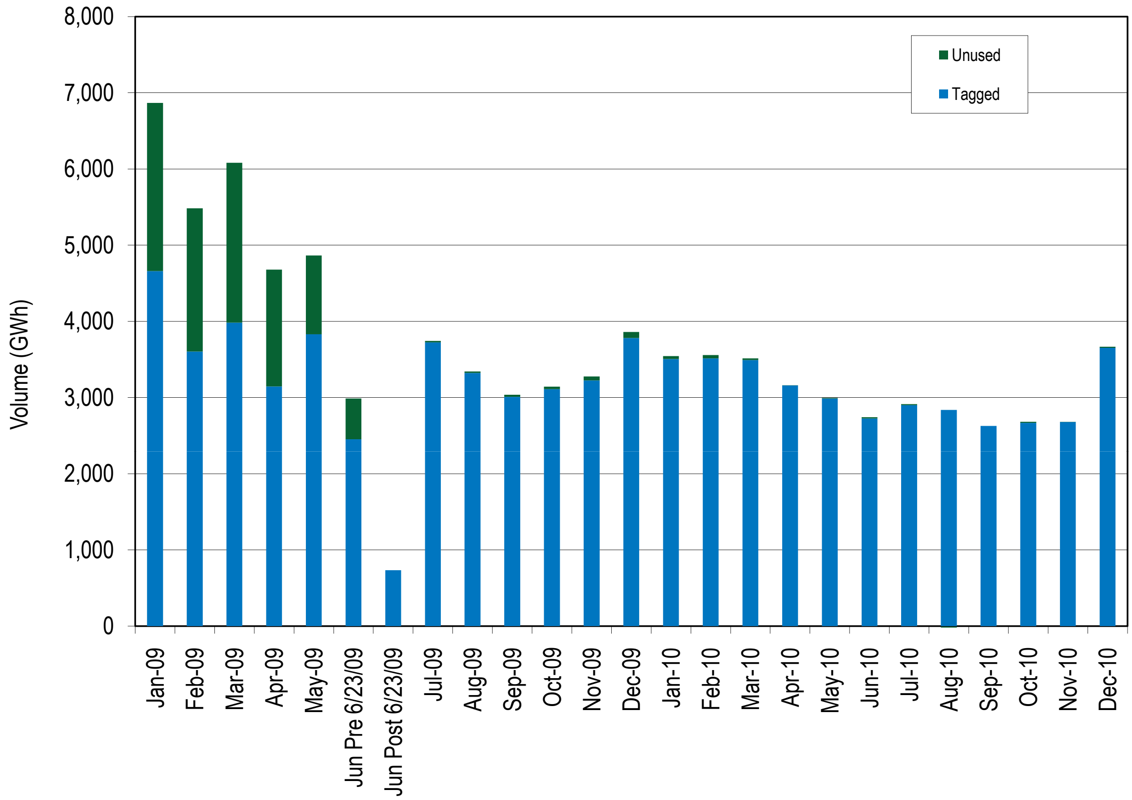
At the December 7, 2010, meeting of the Market Implementation Committee (MIC), PJM and the MMU made a joint recommendation to return to unlimited ATC for non-firm willing to pay congestion service on all paths for all non-firm willing to pay congestion transmission service. The PJM

81 See "Modifications to the Practices of Non-Firm and Spot market Import Service" (April 20, 2007) (Accessed January 15, 2010) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

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

Stakeholders agreed with recommendation, and requested PJM to determine what modifications, if any, to the PJM/MISO Joint Operating Agreement (JOA) would be needed to implement the change, as well as what system modifications would be required. The MMU believes that there are no JOA issues resulting from this change, and that the system modifications required would be minimal enough to allow for an implementation in the first half of 2011.

Figure 4-27 Spot import service utilization: Calendar years 2009 and 2010



Real-Time Dispatchable Transactions

Dispatchable transactions, also known as “real-time with price” transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction. For example, an import dispatchable transaction would specify the minimum price the market participant wishes to receive when selling into the PJM market. If the interface pricing point for the transaction is expected to be greater than the price specified by the market participant, the transaction would be loaded for the next hour. For an export dispatchable transaction, the market participant specifies the maximum price they are willing to buy from at the interface pricing point. PJM dispatchers evaluate dispatchable transactions 30 minutes prior to the hour. If they believe the LMP at the interface pricing point will be economic they will load the transaction for the next hour. Once loaded, the transaction will flow for the entire hour. Import dispatchable transactions receive the hourly integrated import pricing point LMP for the hours when energy flows. If the hourly integrated import pricing point LMP is less than the price specified, the market participant is made whole through balancing operating reserve credits. Exporting dispatchable transactions are not made whole, as Schedule 6 of the PJM Open Access Transmission Tariff does not include export transactions in the calculation for balancing operating reserve credits.

Dispatchable transactions were initially a valuable tool for market participants. Currently, real-time LMPs are readily available to market participants, and the timing requirement for submitting transactions has been reduced to 20 minutes notification. The value that dispatchable transactions once provided market participants no longer exists but the risk to other market participants is substantial.

In 2010, balancing operating reserve credits of $24 million for the calendar year 2010 were paid to three market participants. This was an increase from the 2009 total of $91,000.

The MMU recommends that dispatchable transactions be eliminated as an option for market participants. Alternatively, the MMU recommends that the evaluation of dispatchable transactions be modified from the manual process implemented today, and be included in the Generation Control Application (GCA) tool and modeled similar to a unit being bid with a one hour minimum run time. This will eliminate the potential for a dispatchable transaction to be loaded, and inadvertently continue to flow in subsequent hours where the transaction would not be economic, thus accruing a large amount of balancing operating reserve credits. Including dispatchable transactions in the GCA software would provide the most economic dispatch of PJM system resources.