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

- Real-time net exports decreased to -802.0 GWh during the first three months of 2011 from -842.3 GWh during the first three months of 2010. During the first three months of 2011, there were day-ahead net imports of 3,813.9 GWh compared to net exports of -780.9 GWh during the first three months of 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 in 62 percent of hours between PJM and the Midwest ISO and in 47 percent of hours between PJM and NYISO during the first three months of 2011.
- During the first three months of 2011, net scheduled interchange was -74 GWh and net actual interchange was -211 GWh for a difference of 137 GWh or 185.1 percent (21.4 percent during the first three months of 2010 and 5.2 percent for the calendar year 2010). This difference is system inadvertent.
- PJM initiated the same number of TLRs during the first three months of 2011 as during the first three months of 2010 (13 TLRs).
- The average daily volume of up-to congestion bids increased from 376 bids per day, for the period between March 1, 2009 through May 14, 2010, to 762 bids per day for the period between May 15, 2010 through September 16, 2011, to 1,338 bids per day for the period between September 17, 2010 through March 31, 2011. A significant increase in bid volume occurred following the September 17, 2010 modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids.
- Total uncollected congestion charges during the first three months of 2011 were $4,669, compared to $978,756 for the first three months of 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present.
- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were $1.1 million during the first three months of 2011, an increase from $92,742 in the first three months of 2010.

Summary Recommendations

- In this *2011 State of the Market Report for PJM: January through March*, the recommendations from the 2010 State of the Market Report for PJM remain MMU recommendations.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first three months of 2011, PJM was a net exporter of energy in the Real-Time Energy Market in February and March, and a net importer of energy in January. During the first three months of 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 -267 GWh compared to -281 GWh for the first three months of 2010.[1] Gross monthly import volumes averaged 3,775 GWh compared to 3,837 GWh for the first three months of 2010 while gross monthly exports averaged 4,042 GWh compared to 4,118 GWh for the first three months of 2010.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in all months. During the first three months of 2010, PJM was a net exporter of energy in the Day-Ahead

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.

Energy Market in all months. In the Day-Ahead Energy Market, monthly net interchange averaged 1,271 GWh compared to -260 GWh for the first three months of 2010. Gross monthly import volumes averaged 9,387 GWh compared to 5,182 GWh for the first three months of 2010 while gross monthly exports averaged 8,116 GWh compared to 5,442 GWh for the first three months of 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first three months of 2011 was the significant increase in up-to congestion transactions. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 1,078 bids per day (with an average cleared volume of 423,077 MWh per day) during the first three months of 2011, compared to an average of 337 bids per day (with an average cleared volume of 178,843 MWh per day) during the first three months of 2010. (See Figure 4-20).

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** During the first three months of 2011, gross imports in the Day-Ahead Energy Market were 249 percent of gross imports in the Real-Time Energy Market compared to 210 percent for the calendar year 2010, gross exports in the Day-Ahead Energy Market were 201 percent of gross exports in the Real-Time Energy Market compared to 183 percent for the calendar year 2010, and net interchange in the Day-Ahead Energy Market was 476 percent of net interchange in the Real-Time Energy Market compared to -802.0 GWh in the Real-Time Energy Market and 3,813.9 GWh in the Day-Ahead Energy Market.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, during the first three months of 2011, there were net exports at twelve of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 63 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 29 percent, PJM/MidAmerican Energy Company (MEC) with 18 percent and PJM/Neptune (NEPT) with 16 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 51 percent of the total net PJM exports in the Real-Time Energy Market. Seven PJM interfaces had net imports, with two importing interfaces accounting for 71 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 54 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 17 percent.[2]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, during the first three months of 2011, there were net exports at ten of PJM's 21 interfaces. The top three net exporting interfaces accounted for 60 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 24 percent, PJM/NEPT with 21 percent and PJM/FirstEnergy Corp. (FE) with 15 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND). Combined, these interfaces made up 36 percent of the total net PJM exports in the Day-Ahead Energy Market. Ten PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 87 percent of the total net imports: PJM/OVEC with 35 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 32 percent and PJM/Michigan Electric Coordinated System (MECS) with 20 percent.[3]

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** During the first three months of 2011, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. During the first three months of 2011, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $34.34 while the Midwest ISO LMP at the border was $35.76, a difference of $1.42, while the average hourly flow during the first three months of 2011 was -1,712 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 38 percent of hours during the first three months of 2011. During the first three months of 2011, when the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $15.93. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was -$7.93. While the average hourly LMP difference at the PJM/MISO border was only $1.42, the average of the absolute values of the hourly differences was $11.05.

- **PJM and New York ISO Interface Prices.** During the first three months of 2011, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface

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

3 In the Day-Ahead Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. During the first three months of 2011, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was consistent with the direction of the average flow. During the first three months of 2011, the PJM average hourly LMP at the PJM/NYISO border was $46.77 while the NYISO LMP at the border was $47.35, a difference of $0.58, while the average hourly flow was -787 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is consistent with the fact that the average PJM price was lower than the average NYISO price.) The direction of flows was consistent with price differentials in only 53 percent of the hours during the first three months of 2011. During the first three months of 2011, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $15.25. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was -$15.50. While the average hourly LMP difference at the PJM/NYISO border was only $0.58, the average of the absolute value of the hourly difference was $15.35.

- **Neptune Underwater Transmission Line to Long Island, New York.** The Neptune line is a 65-mile direct current (DC) merchant 230 kV transmission line from PJM (Sayreville, New Jersey), to NYISO (Nassau County on Long Island) 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. During the first three months of 2011, the average difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. During the first three months of 2011, the PJM average hourly LMP at the Neptune Interface was $52.51 while the NYISO LMP at the Neptune Bus was $60.11, a difference of $7.60, while the average hourly flow in 2010 was -533 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 65 percent of the hours during the first three months of 2011. While the average hourly LMP difference at the PJM/Neptune border was only $7.60, the average of the absolute value of the hourly difference was $23.15.

- **Linden Variable Frequency Transformer (VFT) Facility.** The Linden VFT facility is a merchant transmission connection, with a capacity of 300 MW, providing a 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.[4] The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line. 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. On March 31, 2011, PJM, on behalf of Linden VFT, LLC, submitted a revision to Schedule 16. The revision seeks to add Schedule 16-A to the Tariff to provide the terms and conditions for transmission service on the Linden VFT Facility for imports into PJM.[5] The requested effective date for this revision, which allows for the bidirectional flow across the Linden VFT, is June 1, 2011. During the first three months of 2011, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. During the first three months of 2011, the PJM average hourly LMP at the Linden Interface was $51.43 while the NYISO LMP at the Linden Bus was $57.96, a difference of $6.53, while the average hourly flow was -193 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 during the first three months of 2011. While the average hourly LMP difference at the PJM/Linden border was $6.53, the average of the absolute value of the hourly difference was $20.54.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[6] 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 during the first three months of 2011.

4 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.

5 See Docket No. ER11-3250-000 (March 31, 2011).

6 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) (Accessed May 5, 2011) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (2,285 KB).

- **PJM and Midwest ISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during the first three months of 2011. 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.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[7] 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 during the first three months of 2011.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[8] 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 during the first three months of 2011. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP).

- **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 (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

Other Agreements/Protocols with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During the first three months of 2011, 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. Loop flows result, in part, from a mismatch between incentives to use a particular scheduled path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match pricing with physical flows and their impacts on the transmission system. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

  During the first three months of 2011, net scheduled interchange was -74 GWh and net actual interchange was -211 GWh for a difference of 137 GWh or 185.1 percent (21.4 percent during the first three months of 2010 and 5.2 percent for the calendar year 2010).

7 See "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed May 4, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).
8 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) (Accessed May 4, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (642 KB).
9 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed May 4, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).
10 111 FERC ¶ 61,228 (2005).

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 2010, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-4,863 GWh during the first three months of 2011 and -15,106 GWh for the calendar year 2010). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (872 GWh during the first three months of 2011 and 4,015 GWh for the calendar year 2010). 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.

- **Loop Flows at PJM's Southern Interfaces.** The difference between scheduled and actual power flows at PJM's southern interfaces was significant during the first three months of 2011. 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 840 GWh and the actual flow was 1,712 GWh, a difference of 872 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 7 GWh and the actual flow was 2,650 GWh, a difference of 2,643 GWh.

- **PJM Transmission Loading Relief Procedures (TLRs).** During the first three months of 2011, PJM issued 13 TLRs of level 3a or higher. Of the 13 TLRs issued, 8 events were TLR level 3a, and the remaining 5 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 13 TLRs during the first three months of 2011, compared to 13 during the first three months of 2010, 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.

- **Marginal Loss Surplus Allocation.** On May 15, 2010, 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.

  As a result, on September 17, 2010, the marginal loss surplus allocation methodology was modified to mitigate the incentive of submitting noneconomic transactions to benefit from loss surplus allocations.

- **Up-To Congestion.** The May 15, 2010, modification to the marginal loss surplus allocation provided an allocation to up-to congestion transactions. In June and July of 2010, there was a significant increase in the total up-to congestion bids (Figure 4-19). This increase in activity was the result of the changes to the allocation methodology that provided an inappropriate incentive to submit noneconomic up-to congestion transactions to obtain a portion of the loss surplus.

  As part of the September 2010, marginal loss surplus allocation modification, the up-to congestion product was modified to eliminate the requirement for up-to congestion transactions to obtain transmission service. 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.

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

Prior to the May 15, 2010, modification to the marginal surplus allocation, the average daily volume of up-to congestion was 376 bids per day (March 1, 2009 through May 14, 2010). The average daily volume of up-to congestion transactions increased to 762 bids per day for the period between the initial May 15, 2010, modification and the additional modification to the marginal loss surplus allocation methodology made on September 17, 2010. The average daily volume of up-to congestion bids further increased to 1,338 bids per day following the additional modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids, which was implemented as part of the September 17, 2010 marginal loss surplus allocation methodology changes (September 17, 2010 through March 31, 2011). (See Figure 4-20.)

- **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.

  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.** Real-Time 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. Once the transaction is submitted and the NERC Tag is implemented, PJM should curtail the tag to 0 MW pending the real-time economic evaluation during the operating day for which the transaction is submitted. 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. Dispatchable transactions receive the hourly integrated pricing point LMP for the hours when energy flows. For import transactions, 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. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants. The value that dispatchable transactions once provided market participants no longer exist, but the risk to other market participants is substantial, as they are subject to providing the operating reserve credits. Dispatchable transactions now only serve as a potential mechanism for receiving those operating reserve credits. During the first three months of 2011, $1.1 million in balancing operating reserve credits were paid due to the uneconomic loading of dispatchable transactions comparted to $92,742 during first three months of 2010.

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 during the first three months of 2011, including evolving transaction patterns, economics and issues. During the first three months of 2011, PJM was a net exporter of energy in the Real-Time Market and a net importer of energy in the Day-Ahead Market. A large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 63 percent of the total real-time net exports and two interfaces accounted for 71 percent of the real-time net import volume. Three interfaces accounted for 60 percent of the total day-ahead net exports and three interfaces accounted for 87 percent of the day-ahead net import volume.

During the first three months of 2011, 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 many hours, 62 percent between PJM and the Midwest ISO and 47 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.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through March 2011 (See 2010 SOM, Figure 4-1)

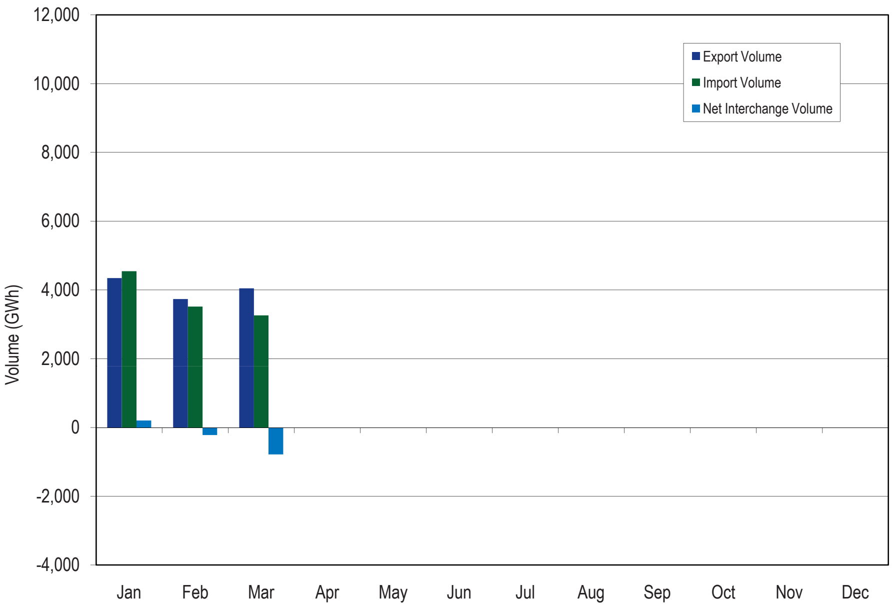


Figure 4-2 PJM day-ahead scheduled imports and exports: January through March 2011 (See 2010 SOM, Figure 4-2)

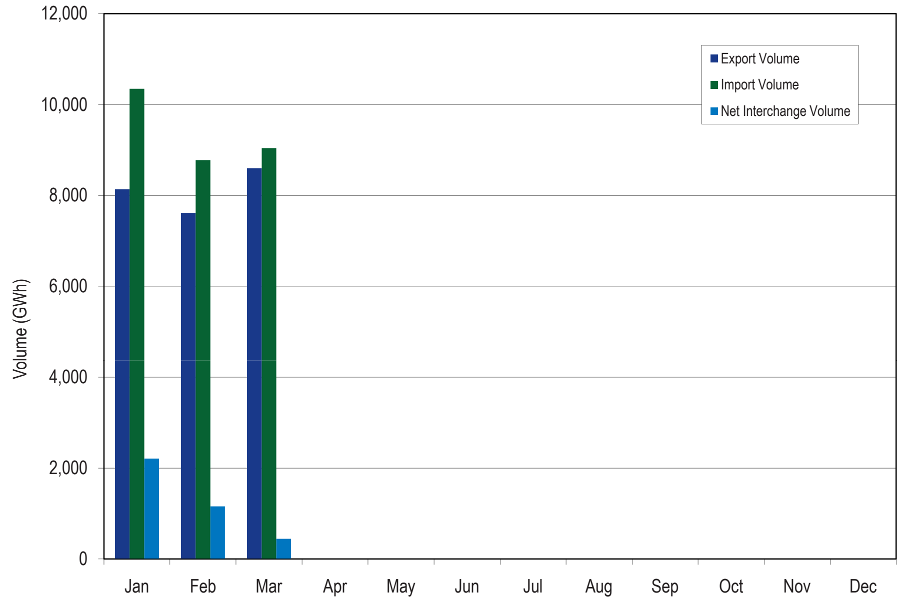
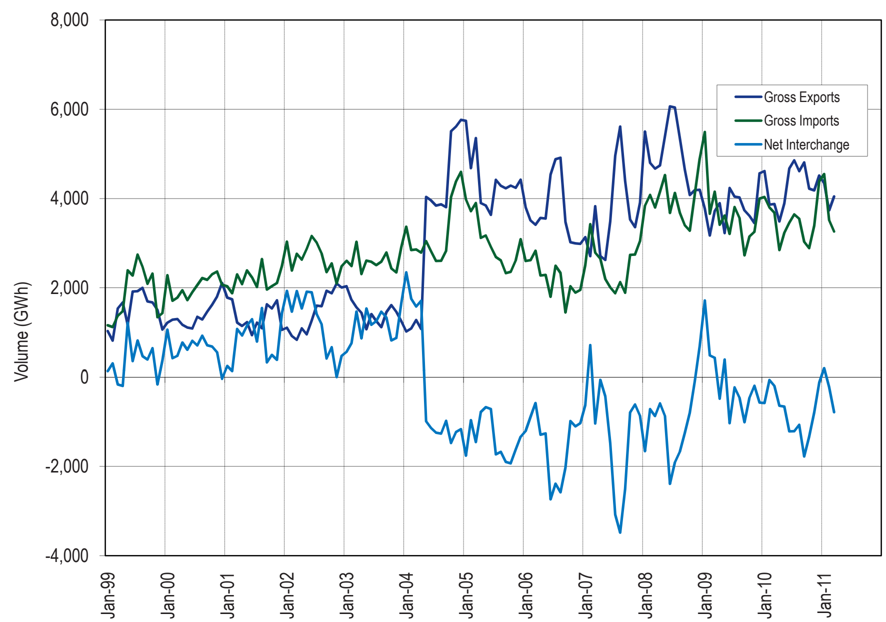


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through March 2011 (See 2010 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through March 2011 (See 2010 SOM, Table 4-1)

	Jan	Feb	Mar	Total
CPLE	(162.6)	(76.3)	(85.5)	(324.4)
CPLW	0.0	0.0	0.0	0.0
DUK	(25.6)	218.7	(17.1)	176.0
EKPC	(61.4)	(10.1)	5.6	(65.9)
LGEE	392.9	385.9	314.6	1,093.4
MEC	(426.0)	(403.3)	(462.2)	(1,291.5)
MISO	(77.3)	(389.0)	(744.4)	(1,210.7)
ALTE	(116.1)	(128.3)	(76.0)	(320.4)
ALTW	(30.9)	(14.5)	(28.6)	(74.0)
AMIL	(2.9)	45.5	14.3	56.9
CIN	(85.5)	(314.7)	(454.6)	(854.8)
CWLP	0.0	0.0	0.0	0.0
FE	149.9	(43.9)	(159.1)	(53.1)
IPL	21.8	3.5	8.8	34.1
MECS	193.0	190.8	112.6	496.4
NIPS	(114.3)	(51.0)	(69.7)	(235.0)
WEC	(92.3)	(76.4)	(92.1)	(260.8)
NYISO	(1,361.0)	(1,279.3)	(1,032.0)	(3,672.3)
LIND	(159.1)	(148.1)	(117.7)	(424.9)
NEPT	(412.9)	(378.8)	(383.7)	(1,175.4)
NYIS	(789.0)	(752.4)	(530.6)	(2,072.0)
OVEC	1,242.2	1,110.7	1,065.8	3,418.7
TVA	681.6	222.8	170.3	1,074.7
Total	202.8	(219.9)	(784.9)	(802.0)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through March 2011 (See 2010 SOM, Table 4-2)

	Jan	Feb	Mar	Total
CPLE	6.4	7.4	4.6	18.4
CPLW	0.0	0.0	0.0	0.0
DUK	271.7	309.8	186.2	767.7
EKPC	31.7	46.5	41.0	119.2
LGEE	393.0	386.3	324.1	1,103.4
MEC	53.2	30.8	19.1	103.1
MISO	1,141.5	833.9	736.6	2,712.0
ALTE	0.0	0.0	0.0	0.0
ALTW	0.0	0.0	0.0	0.0
AMIL	23.9	68.0	42.2	134.1
CIN	400.0	270.3	315.2	985.5
CWLP	0.0	0.0	0.0	0.0
FE	436.8	220.5	122.3	779.6
IPL	25.4	4.8	15.3	45.5
MECS	250.9	270.3	241.4	762.6
NIPS	0.0	0.0	0.2	0.2
WEC	4.5	0.0	0.0	4.5
NYISO	681.0	534.7	646.6	1,862.3
LIND	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0
NYIS	681.0	534.7	646.6	1,862.3
OVEC	1,242.2	1,110.7	1,091.3	3,444.2
TVA	725.7	255.5	212.0	1,193.2
Total	4,546.4	3,515.6	3,261.5	11,323.5

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through March 2011 (See 2010 SOM, Table 4-3)

	Jan	Feb	Mar	Total
CPLE	169.0	83.7	90.1	342.8
CPLW	0.0	0.0	0.0	0.0
DUK	297.3	91.1	203.3	591.7
EKPC	93.1	56.6	35.4	185.1
LGEE	0.1	0.4	9.5	10.0
MEC	479.2	434.1	481.3	1,394.6
MISO	1,218.8	1,222.9	1,481.0	3,922.7
ALTE	116.1	128.3	76.0	320.4
ALTW	30.9	14.5	28.6	74.0
AMIL	26.8	22.5	27.9	77.2
CIN	485.5	585.0	769.8	1,840.3
CWLP	0.0	0.0	0.0	0.0
FE	286.9	264.4	281.4	832.7
IPL	3.6	1.3	6.5	11.4
MECS	57.9	79.5	128.8	266.2
NIPS	114.3	51.0	69.9	235.2
WEC	96.8	76.4	92.1	265.3
NYISO	2,042.0	1,814.0	1,678.6	5,534.6
LIND	159.1	148.1	117.7	424.9
NEPT	412.9	378.8	383.7	1,175.4
NYIS	1,470.0	1,287.1	1,177.2	3,934.3
OVEC	0.0	0.0	25.5	25.5
TVA	44.1	32.7	41.7	118.5
Total	4,343.6	3,735.5	4,046.4	12,125.5

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through March 2011 (See 2010 SOM, Table 4-4)

	Jan	Feb	Mar	Total
CPLE	(11.3)	89.8	126.7	205.2
CPLW	17.1	6.4	1.9	25.4
DUK	91.7	115.8	41.0	248.5
EKPC	(27.5)	(18.4)	27.8	(18.1)
LGEE	19.0	1.8	2.0	22.8
MEC	(458.7)	(421.4)	(463.2)	(1,343.3)
MISO	2,144.3	904.6	(182.2)	2,866.7
ALTE	1,996.5	908.2	99.1	3,003.8
ALTW	164.8	(49.7)	(48.1)	67.0
AMIL	34.6	70.2	67.5	172.3
CIN	(125.8)	(90.5)	(175.1)	(391.4)
CWLP	0.0	0.0	0.0	0.0
FE	(189.4)	(339.7)	(317.2)	(846.3)
IPL	(175.6)	(162.6)	(163.9)	(502.1)
MECS	742.4	580.2	567.2	1,889.8
NIPS	(280.6)	(111.0)	(130.3)	(521.9)
WEC	(22.6)	99.5	(81.4)	(4.5)
NYISO	(892.0)	(681.9)	(496.7)	(2,070.6)
LIND	(105.0)	(104.7)	(77.9)	(287.6)
NEPT	(427.9)	(379.7)	(385.0)	(1,192.6)
NYIS	(359.1)	(197.5)	(33.8)	(590.4)
OVEC	1,046.0	1,051.1	1,279.5	3,376.6
TVA	282.8	111.2	106.7	500.7
Total	2,211.4	1,159.0	443.5	3,813.9

Table 4-5 Day-ahead gross import volume by interface (GWh): January through March 2011 (See 2010 SOM, Figure 4-5)

	Jan	Feb	Mar	Total
CPLE	137.6	146.3	197.4	481.3
CPLW	19.5	6.5	8.1	34.1
DUK	150.8	155.5	88.5	394.8
EKPC	5.4	0.0	28.3	33.7
LGEE	21.6	2.1	13.5	37.2
MEC	21.7	19.8	20.1	61.6
MISO	7,393.7	5,782.6	5,316.8	18,493.1
ALTE	4,872.3	3,576.6	3,109.0	11,557.9
ALTW	375.6	52.1	29.0	456.7
AMIL	44.8	71.1	70.7	186.6
CIN	266.2	440.5	360.6	1,067.3
CWLP	0.0	0.0	0.0	0.0
FE	232.7	140.5	141.0	514.2
IPL	17.0	2.9	0.0	19.9
MECS	1,409.4	1,207.9	1,438.1	4,055.4
NIPS	32.0	48.2	27.0	107.2
WEC	143.7	242.8	141.4	527.9
NYISO	910.1	988.6	1,149.1	3,047.8
LIND	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0
NYIS	910.1	988.6	1,149.1	3,047.8
OVEC	1,272.8	1,355.2	1,898.8	4,526.8
TVA	412.1	318.7	318.9	1,049.7
Total	10,345.3	8,775.3	9,039.5	28,160.1

Table 4-6 Day-ahead gross export volume by interface (GWh): January through March 2011 (See 2010 SOM, Figure 4-6)

	Jan	Feb	Mar	Total
CPLE	148.9	56.5	70.7	276.1
CPLW	2.4	0.1	6.2	8.7
DUK	59.1	39.7	47.5	146.3
EKPC	32.9	18.4	0.5	51.8
LGEE	2.6	0.3	11.5	14.4
MEC	480.4	441.2	483.3	1,404.9
MISO	5,249.4	4,878.0	5,499.0	15,626.4
ALTE	2,875.8	2,668.4	3,009.9	8,554.1
ALTW	210.8	101.8	77.1	389.7
AMIL	10.2	0.9	3.2	14.3
CIN	392.0	531.0	535.7	1,458.7
CWLP	0.0	0.0	0.0	0.0
FE	422.1	480.2	458.2	1,360.5
IPL	192.6	165.5	163.9	522.0
MECS	667.0	627.7	870.9	2,165.6
NIPS	312.6	159.2	157.3	629.1
WEC	166.3	143.3	222.8	532.4
NYISO	1,802.1	1,670.5	1,645.8	5,118.4
LIND	105.0	104.7	77.9	287.6
NEPT	427.9	379.7	385.0	1,192.6
NYIS	1,269.2	1,186.1	1,182.9	3,638.2
OVEC	226.8	304.1	619.3	1,150.2
TVA	129.3	207.5	212.2	549.0
Total	8,133.9	7,616.3	8,596.0	24,346.2

Interface Pricing

Table 4-7 Active interfaces: January through March 2011 (See 2010 SOM, Figure 4-7)

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

Figure 4-4 PJM's footprint and its external interfaces (See 2010 SOM, Figure 4-4)

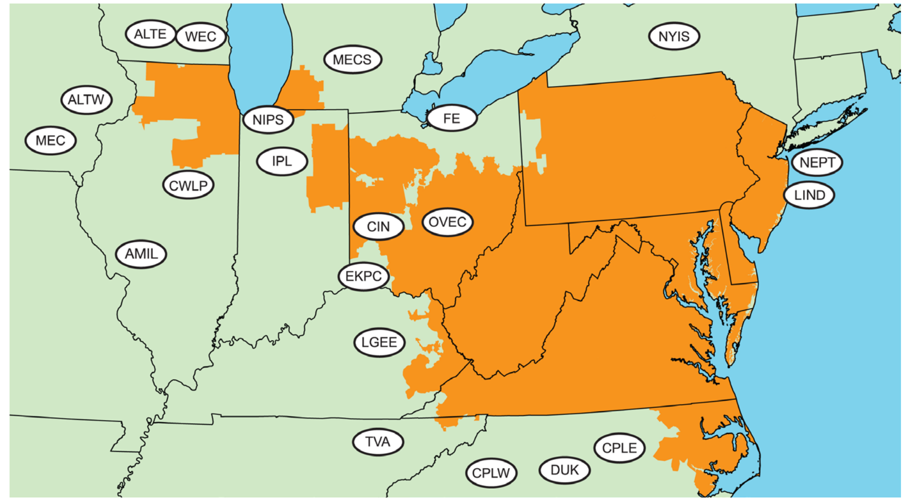


Table 4-8 Active pricing points: 2011 (See 2010 SOM, Table 4-8)

PJM 2011 Pricing Points (January through March)				
CPLEEXP	CPLEIMP	DUKEXP	DUKIMP	LIND
MICHFE	MISO	NCMPAEXP	NCMPAIMP	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO	OVEC
SOUTHEXP	SOUTHIMP			

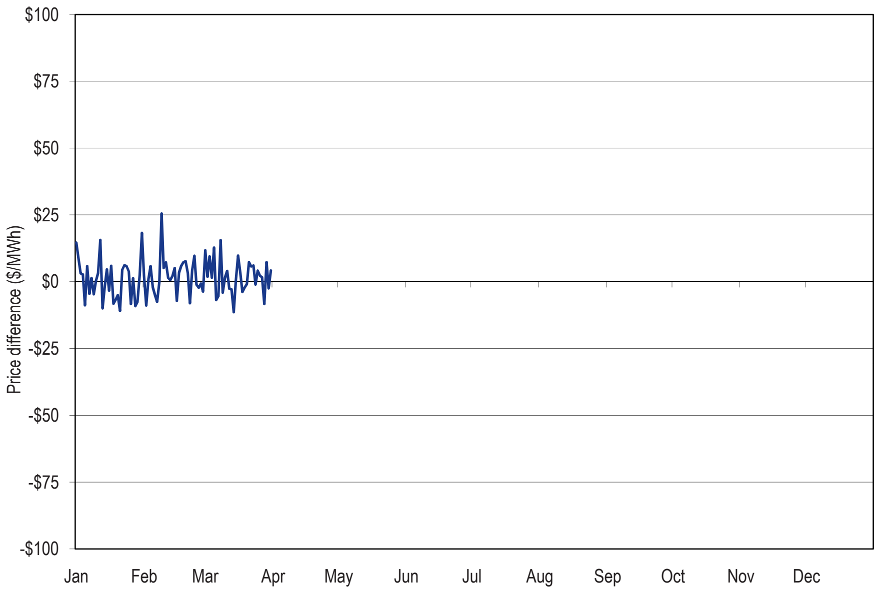
Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

PJM and Midwest ISO Interface Prices

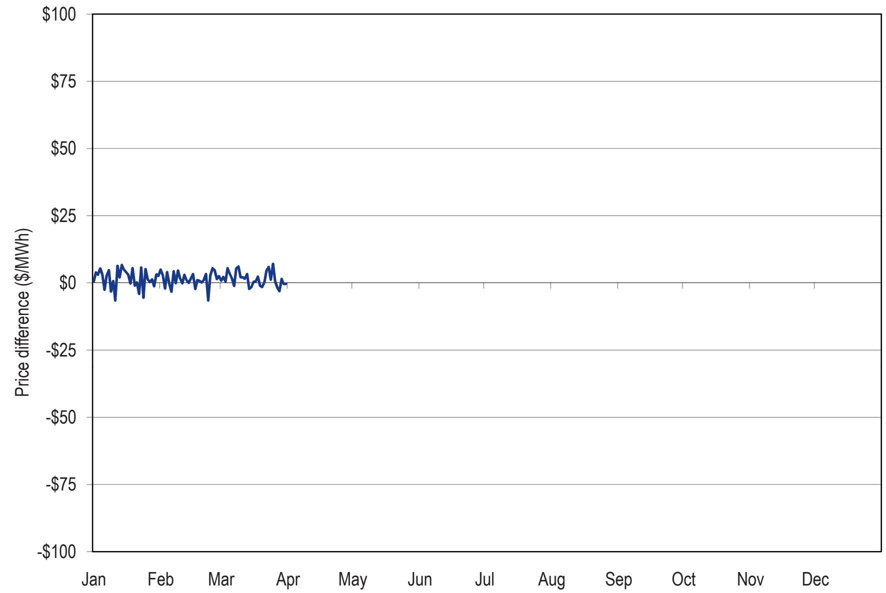
Real-Time Prices

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): January through March 2011 (See 2010 SOM, Figure 4-5)



Day-Ahead Prices

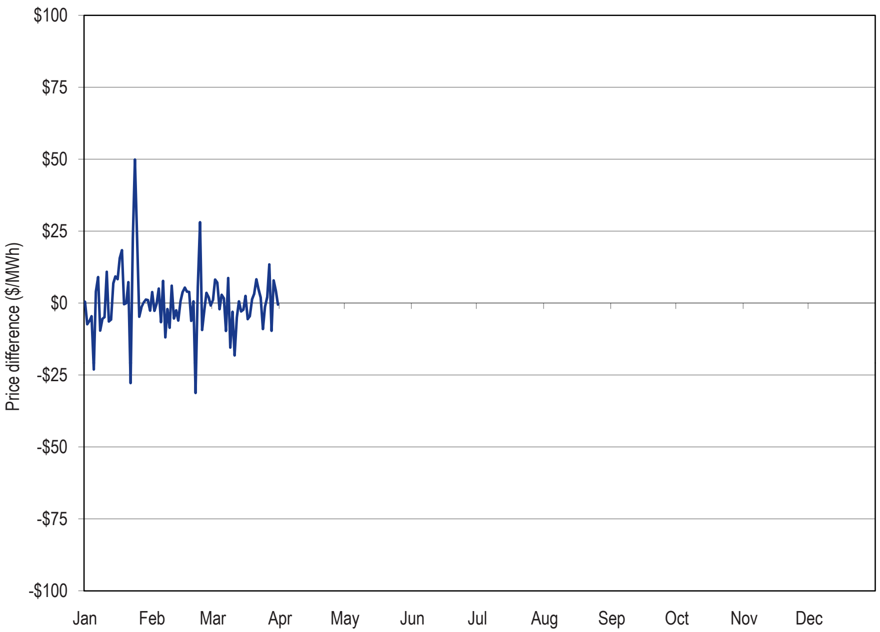
Figure 4-6 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): January through March 2011 (See 2010 SOM, Figure 4-6)



PJM and NYISO Interface Prices

Real-Time Prices

Figure 4-7 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): January through March 2011 (See 2010 SOM, Figure 4-7)



Day-Ahead Prices

Figure 4-8 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through March 2011 (See 2010 SOM, Figure 4-8)

Summary of Interface Prices between PJM and Organized Markets

Figure 4-9 PJM, NYISO and Midwest ISO real-time border price averages: January through March 2011 (See 2010 SOM, Figure 4-9)

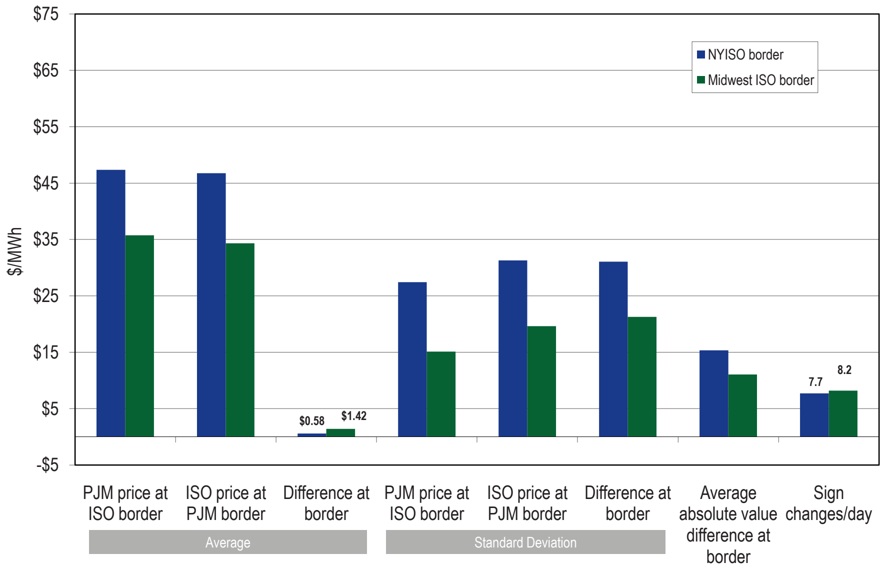
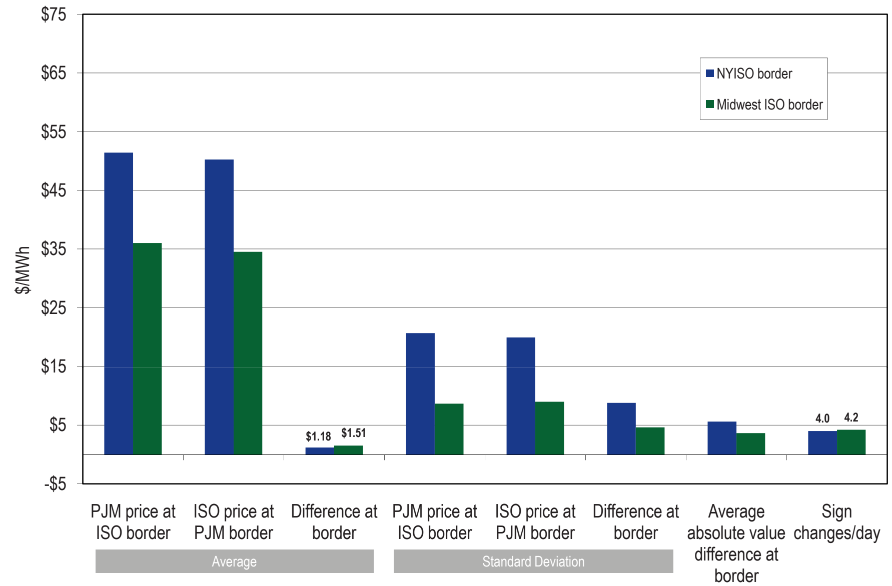
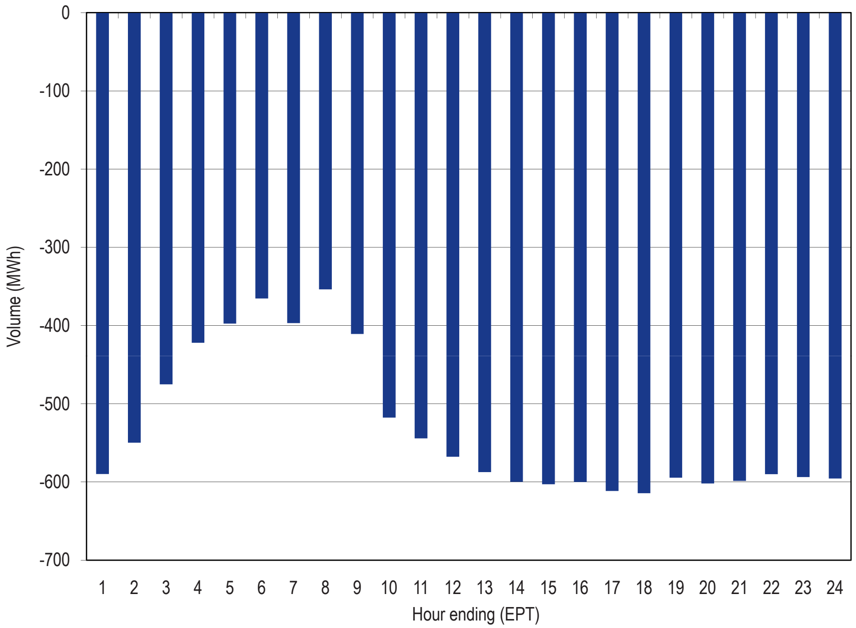


Figure 4-10 PJM, NYISO and Midwest ISO day-ahead border price averages: January through March 2011 (See 2010 SOM, Figure 4-10)



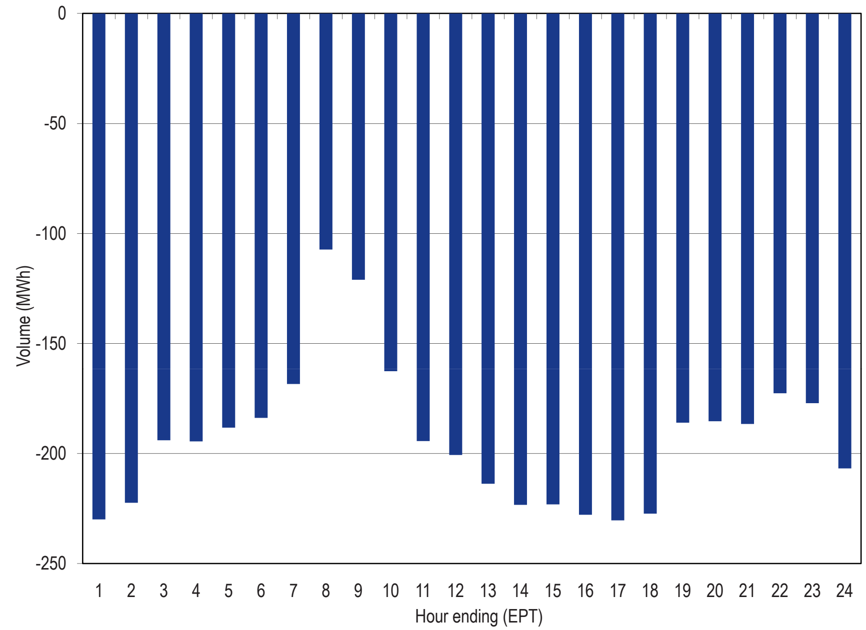
Neptune Underwater Transmission Line to Long Island, New York

Figure 4-11 Neptune hourly average flow: January through March 2011 (See 2010 SOM, Figure 4-11)



Linden Variable Frequency Transformer (VFT) facility

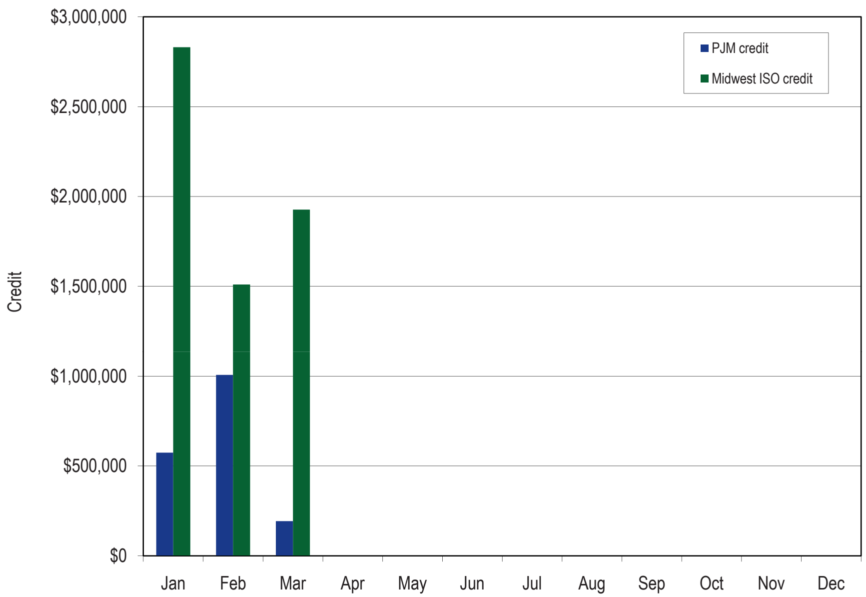
Figure 4-12 Linden hourly average flow: January through March 2011 (See 2010 SOM, Figure 4-12)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement

Figure 4-13 Credits for coordinated congestion management: January through March 2011 (See 2010 SOM, Figure 4-13)



Other Agreements/Protocols with Bordering Areas

Con Edison and PSE&G Wheeling Contracts

Table 4-9 Con Edison and PSE&G wheeling settlement data: January through March 2011 (See 2010 SOM, Table 4-9)

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	($435,152)	($36)	($435,189)	($6,301,035)	$0	($6,301,035)
Congestion Credit			$1,713			($6,290,717)
Adjustments			$15,127			$1,295
Net Charge			($452,028)			($11,613)

Interchange Transaction Issues

Loop Flows

Table 4-10 Net scheduled and actual PJM interface flows (GWh): January through March 2011 (See 2010 SOM, Table 4-10)

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	2,650	7	2,643	37,757%
CPLW	(422)	-	(422)	0%
DUK	(345)	176	(521)	(296%)
EKPC	703	(66)	769	(1,165)%
LGEE	379	1,093	(714)	(65%)
MEC	(763)	(1,289)	526	(41%)
MISO	(3,694)	(572)	(3,122)	546%
ALTE	(1,494)	(320)	(1,174)	367%
ALTW	(554)	(74)	(480)	649%
AMIL	3,183	34	3,149	9,262%
CIN	620	147	473	322%
CWLP	(29)	-	(29)	0%
FE	(1,539)	(352)	(1,187)	337%
IPL	456	(7)	463	(6,614%)
MECS	(4,367)	496	(4,863)	(980%)
NIPS	(1,333)	(235)	(1,098)	467%
WEC	1,363	(261)	1,624	(622%)
NYISO	(3,265)	(3,682)	417	(11%)
LIND	(416)	(416)	-	0%
NEPT	(1,150)	(1,150)	-	0%
NYIS	(1,699)	(2,116)	417	(20%)
OVEC	2,834	3,419	(585)	(17%)
TVA	1,712	840	872	104%
Total	(211)	(74)	(137)	185.1%

Loop Flows at PJM's Southern Interfaces

Figure 4-14 Southwest actual and scheduled flows: January 2006 through March 2011 (See 2010 SOM, Figure 4-14)

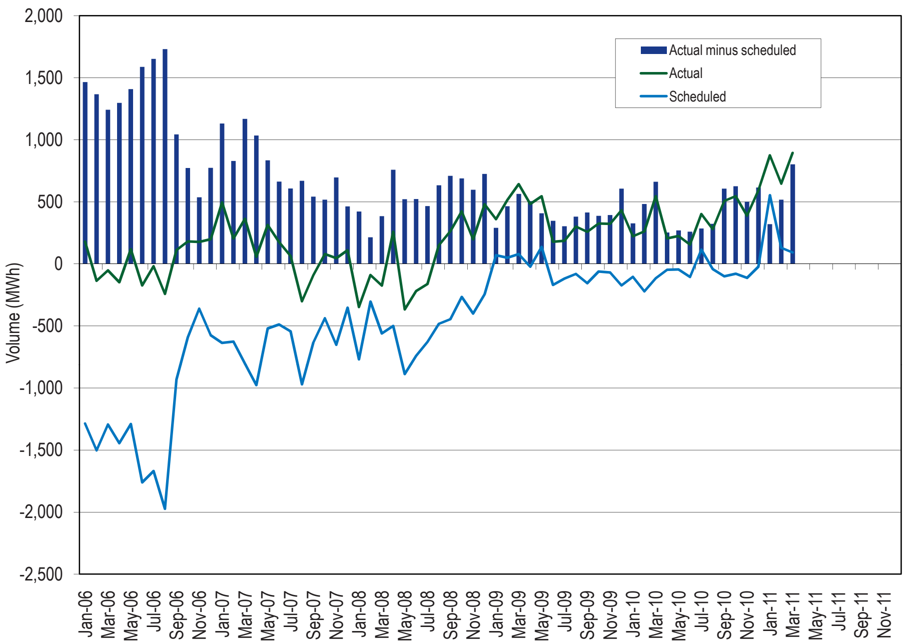
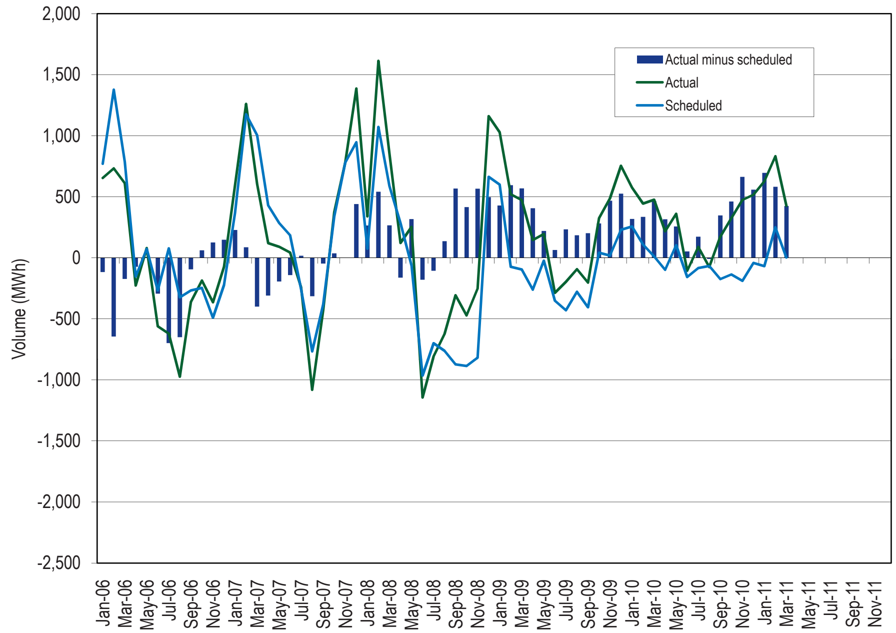


Figure 4-15 Southeast actual and scheduled flows: January 2006 through March 2011 (See 2010 SOM, Figure 4-15)



Dynamic Interface Pricing

Figure 4-16 PJM and Midwest ISO TLR procedures: Calendar year 2010 and January through March 2011 (See 2010 SOM, Figure 4-16)

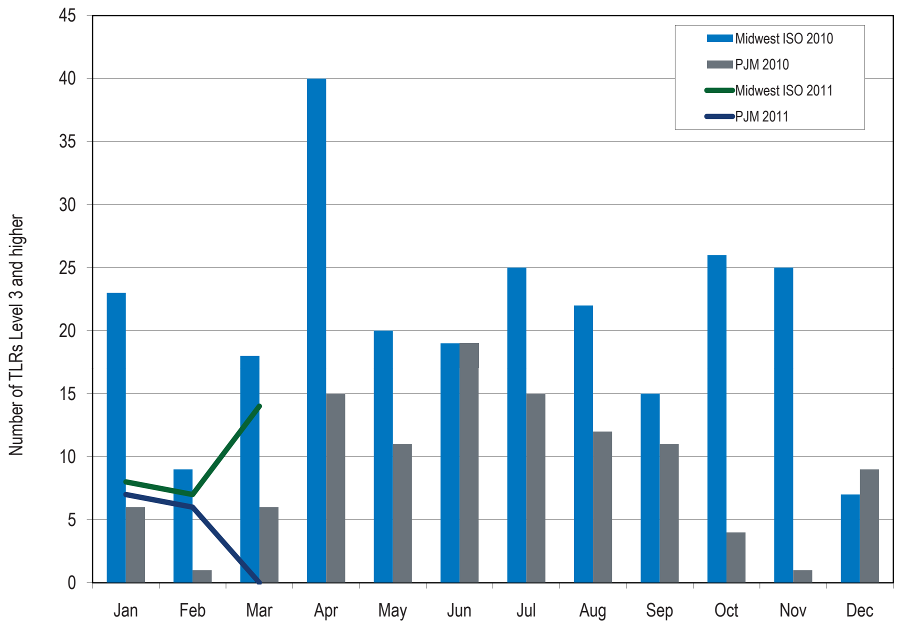


Figure 4-17 Number of different PJM flowgates that experienced TLRs: Calendar year 2010 and January through March 2011 (See 2010 SOM, Figure 4-17)

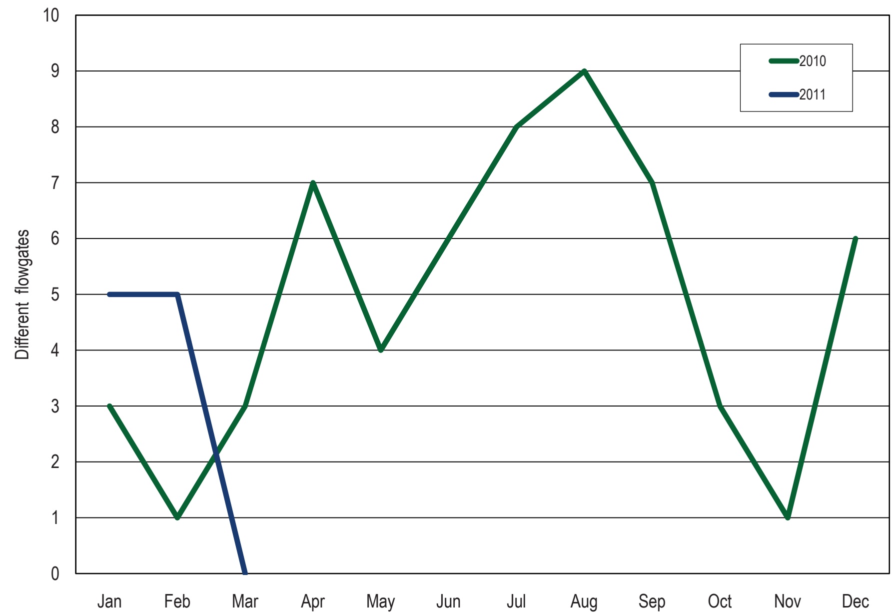


Figure 4-18 Number of PJM TLRs and curtailed volume: January through March 2011 (See 2010 SOM, Figure 4-18)

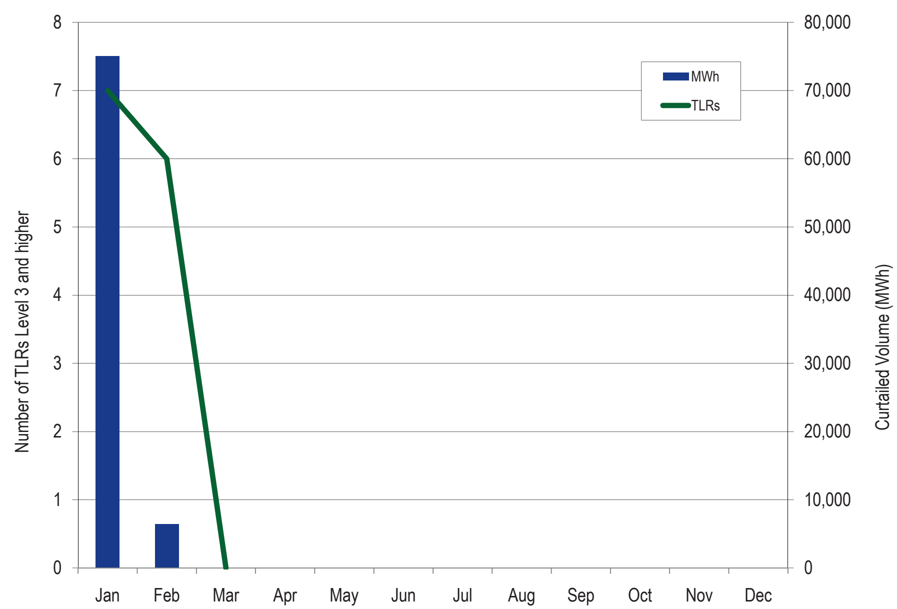


Table 4-11 Number of TLRs by TLR level by reliability coordinator: January through March 2011 (See 2010 SOM, Table 4-11)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2011	ICTE	3	1	49	4	2	0	59
	MISO	19	9	0	1	0	0	29
	NYIS	68	0	0	0	0	0	68
	ONT	11	0	0	0	0	0	11
	PJM	8	5	0	0	0	0	13
	SWPP	63	88	1	7	10	0	169
	TVA	27	46	2	0	8	0	83
Total		199	149	52	12	20	0	432

Up-To Congestion

Figure 4-19 Monthly up-to congestion bids in MWh: January 2006 through March 2011 (See 2010 SOM, Figure 4-19)

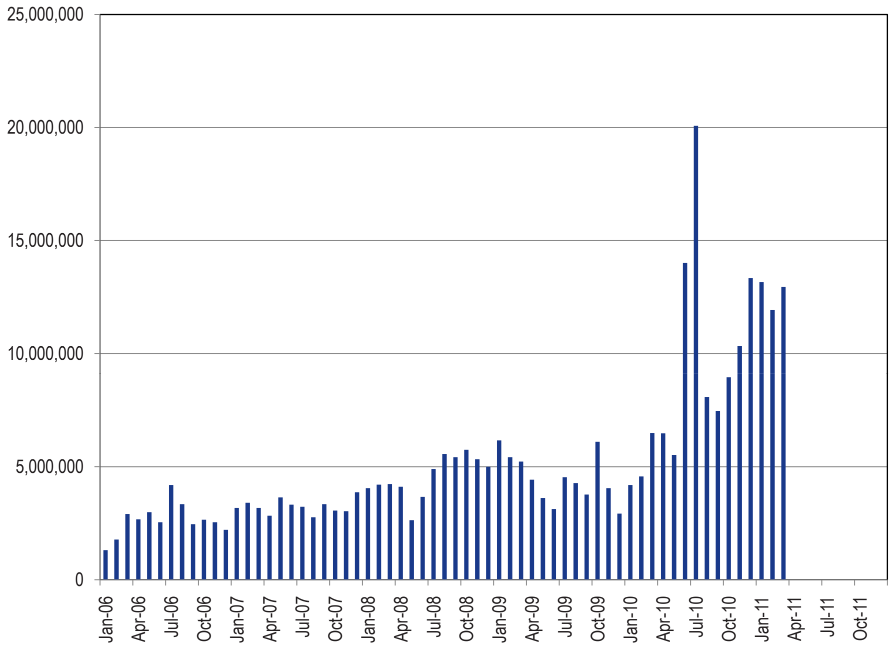


Figure 4-20 Unique up-to congestion bids with approved MWh: March 2009 through March 2011 (New Figure)

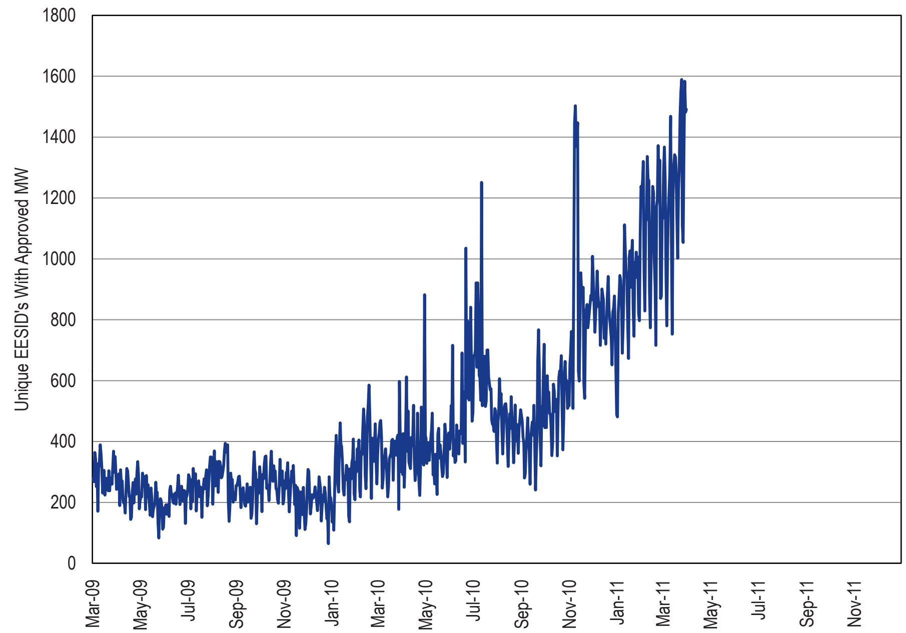


Table 4-12 Up-to congestion MW by Import, Export and Wheels: Calendar years 2006 through March 2011 (See 2010 SOM, Table 4-12)

	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	54,662,719	48,723,549	6,147,957	109,534,225	49.9%	44.5%	5.6%
2011	21,826,485	15,379,380	840,190	38,046,055	57.4%	40.4%	2.2%
TOTAL	146,515,707	168,657,266	11,360,458	326,533,431	44.9%	51.7%	3.5%

Figure 4-21 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction: January through March 2011 (See 2010 SOM, Figure 4-20)

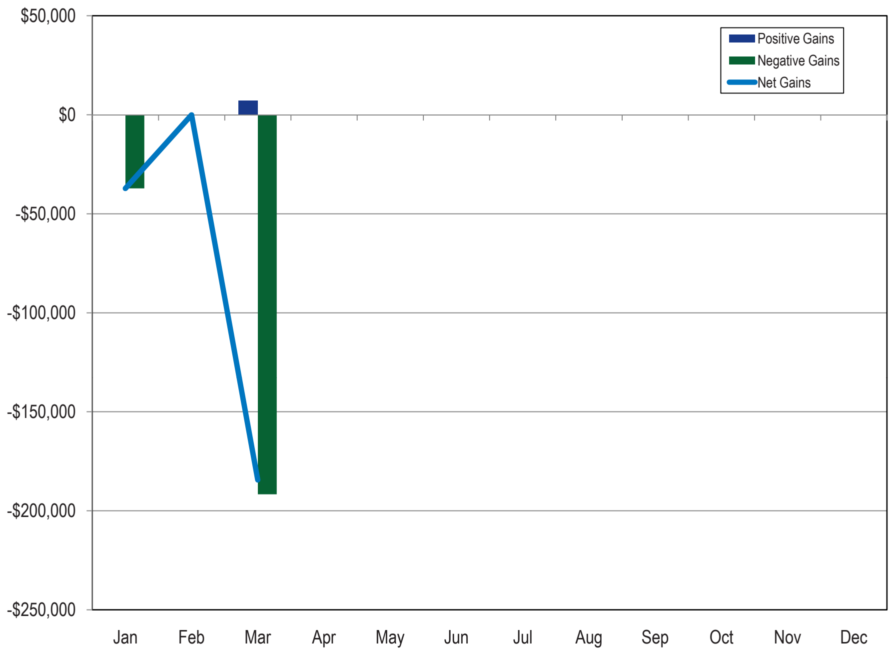
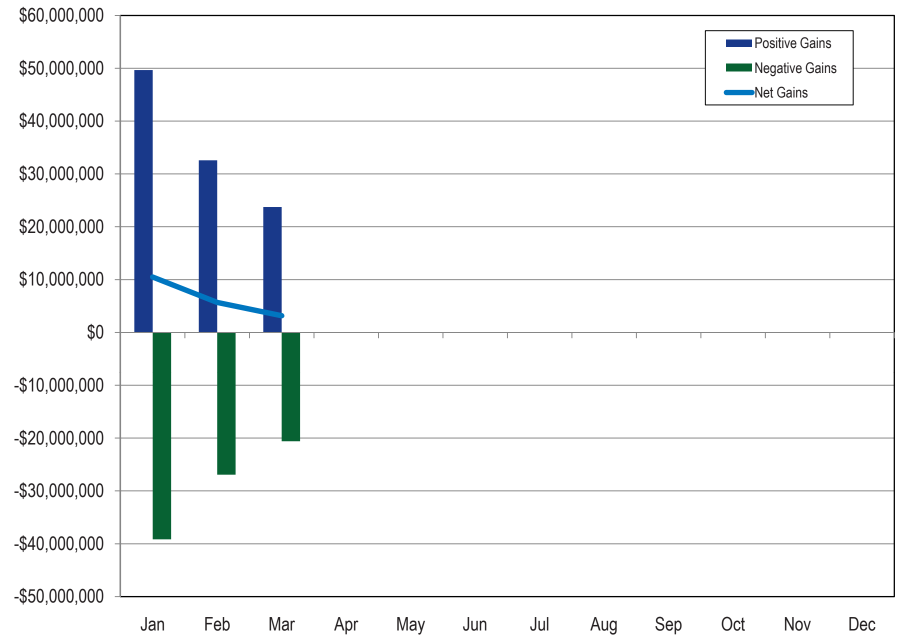


Figure 4-22 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Energy Market transaction: January through March 2011 (See 2010 SOM, Figure 4-21)



Interface Pricing Agreements with Individual Balancing Authorities

Table 4-13 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through March 2011 (See 2010 SOM, Table 4-13)

	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)
2011	$42.19	$36.24	$38.71	$38.71	$3.48	($2.47)	$3.48	($2.47)

Table 4-14 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through March 2011 (See 2010 SOM, Table 4-14)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$40.04	$41.16	$38.71	$38.71	$1.32	$2.44
PEC	$40.71	$42.52	$38.71	$38.71	$2.00	$3.80
NCMPA	$40.65	$40.81	$38.71	$38.71	$1.93	$2.10

Figure 4-23 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March 2011 (See 2010 SOM, Figure 4-22)

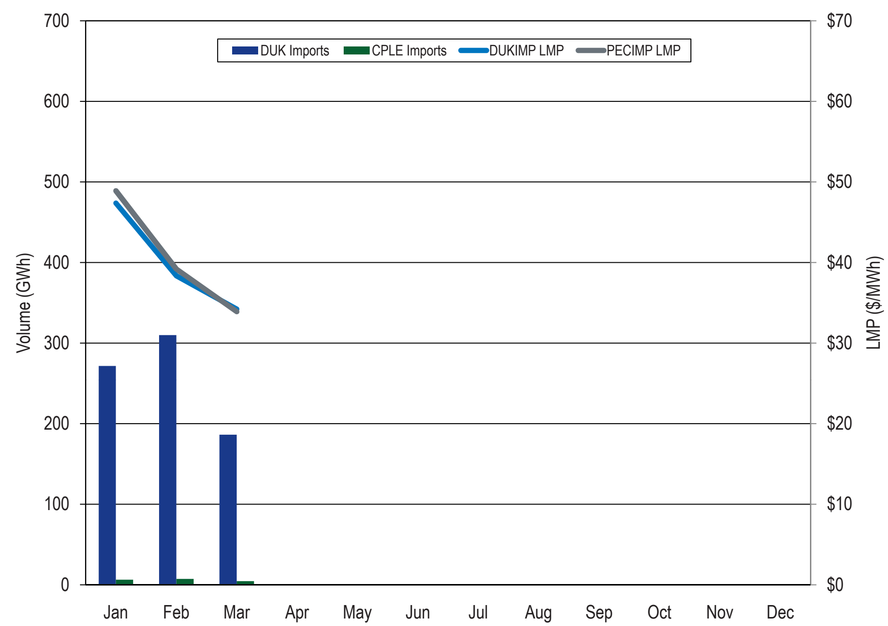


Figure 4-24 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March 2011 (See 2010 SOM, Figure 4-23)

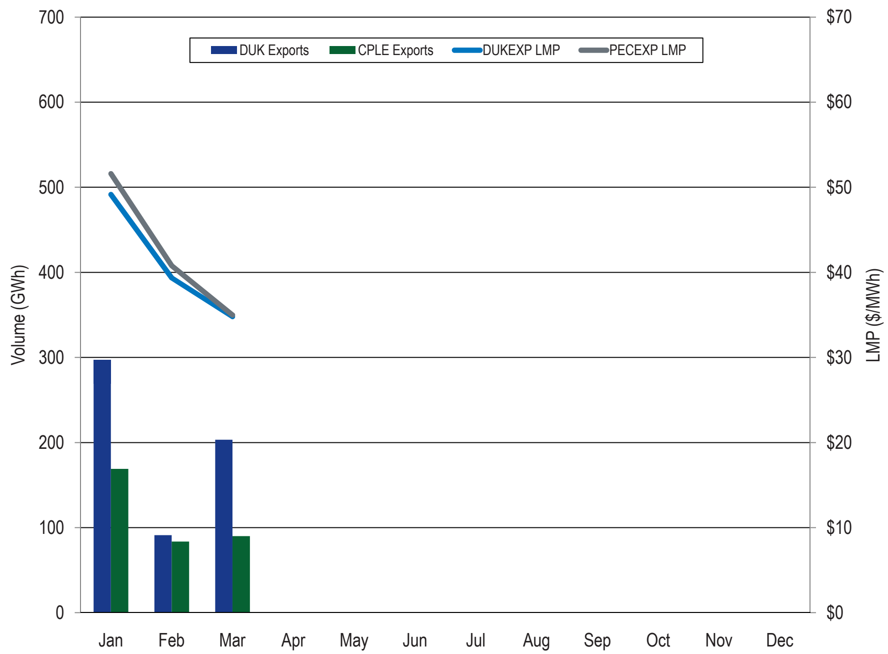


Table 4-16 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through March 2011 (See 2010 SOM, Table 4-16)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$40.86	$42.79	$39.27	$39.27	$1.59	$3.53
PEC	$42.38	$44.60	$39.27	$39.27	$3.11	$5.34
NCMPA	$41.81	$41.95	$39.27	$39.27	$2.54	$2.68

Table 4-15 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through March 2011 (See 2010 SOM, Table 4-15)

	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)
2011	$43.69	$36.97	$39.27	$39.27	$4.42	($2.30)	$4.42	($2.30)

Figure 4-25 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March 2011 (See 2010 SOM, Figure 4-24)

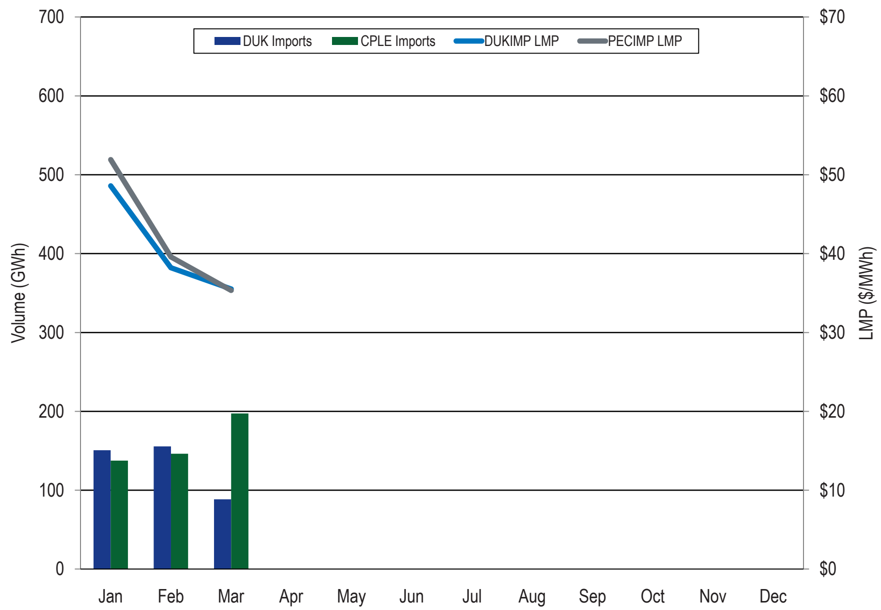
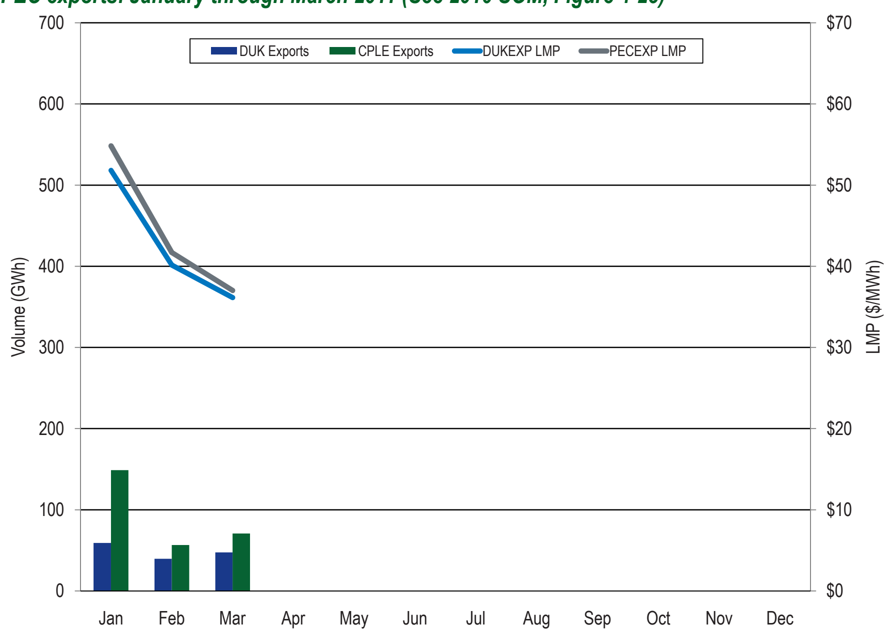
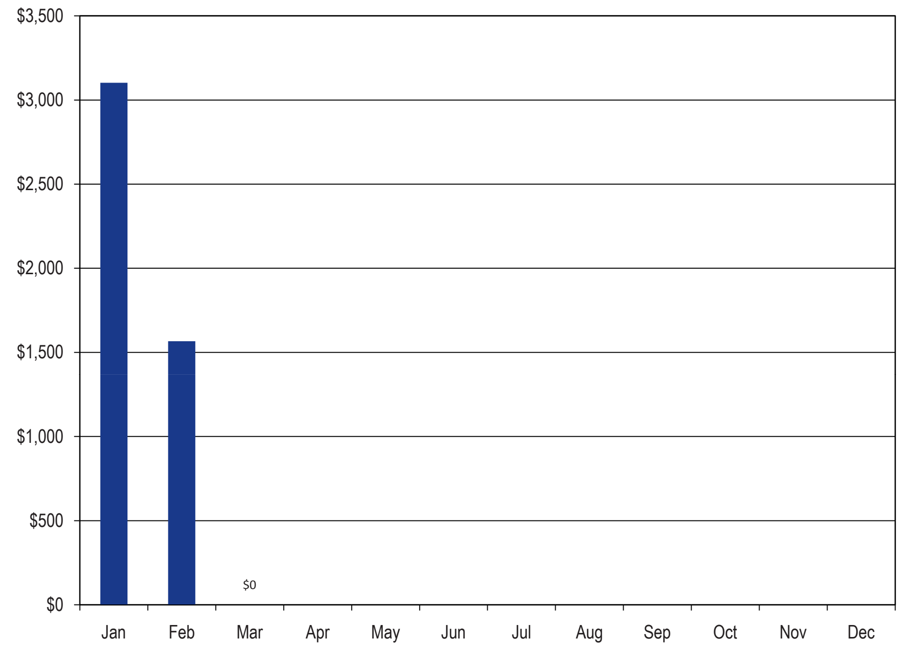


Figure 4-26 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March 2011 (See 2010 SOM, Figure 4-25)



Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-27 Monthly uncollected congestion charges: January through March 2011 (See 2010 SOM, Figure 4-26)



Spot Import

Figure 4-28 Spot import service utilization: Calendar year 2010 and January through March 2011 (See 2010 SOM, Figure 4-27)