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

- On June 1, 2011 at 0100, American Transmission Systems, Inc. (ATSI) integrated into PJM. The affect of this integration on interchange transactions was the elimination of the First Energy (FE) Interface as well as the elimination of the MICHFE Interface Pricing Point.

- Real-time net exports decreased to -2949.1 GWh during the first six months of 2011 from -3,356.4 GWh during the first six months of 2010. During the first six months of 2011, there were day-ahead net imports of 10,914.7 GWh compared to net exports of -5,489.5 GWh during the first six months of 2010.

- The direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences in 59 percent of hours between PJM and MISO and in 47 percent of hours between PJM and NYISO during the first six months of 2011.

- During the first six months of 2011, net scheduled interchange was -1,623 GWh and net actual interchange was -1,876 GWh for a difference of 253 GWh or 15.6 percent (7.7 percent during the first six months of 2010 and 5.2 percent for the calendar year 2010). This difference is system inadvertent.

- PJM initiated fewer TLRs during the first six months of 2011 than during the first six months of 2010 (40 TLRs during the first six months of 2011 compared to 58 TLRs during the first six months of 2010).

- 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, 2010, to 1,634 bids per day for the period between September 17, 2010 through June 30, 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 six months of 2011 were $10,790, compared to $1.2 million for the first six 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 $1.3 million during the first six months of 2011, an increase from $290,515 in the first six months of 2010.

Recommendations

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

Overview

Interchange Transaction Activity

- **American Transmission System, Inc. (ATSI) Integration.** On June 1, 2011 at 0100, First Energy's American Transmission System, Inc. integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduces the total number of external PJM interfaces from 21 to 20 interfaces. The integration also resulted in the elimination of the MICHFE Interface Pricing Point, reducing the total number of interface pricing points from 17 to 16.[1]

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first six months of 2011, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy

1 The tables and figures within this section continue to show that the FE Interace and the MICHFE Interface Pricing Points existed in June, 2011, to account for the single hour in June where FE was still an external interface to PJM.

in the remaining months. During the first six 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 -491 GWh compared to -559 GWh for the first six months of 2010.[2] Gross monthly import volumes averaged 3,464 GWh compared to 3,509 GWh for the first six months of 2010 while gross monthly exports averaged 3,955 GWh compared to 4,068 GWh for the first six months of 2010.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first six months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in all months. During the first six months of 2010, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. In the Day-Ahead Energy Market, monthly net interchange averaged 1,819 GWh compared to -915 GWh for the first six months of 2010. Gross monthly import volumes averaged 9,801 GWh compared to 5,716 GWh for the first six months of 2010 while gross monthly exports averaged 7,982 GWh compared to 6,631 GWh for the first six months of 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first six 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 1,258 bids per day (with an average cleared volume of 427,215 MWh per day) during the first six months of 2011, compared to an average of 379 bids per day (with an average cleared volume of 237,579 MWh per day) during the first six months of 2010. (See Figure 4-18).

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** During the first six months of 2011, gross imports in the Day-Ahead Energy Market were 283 percent of gross imports in the Real-Time Energy Market (163 percent for the first six months of 2010). During the first six months of 2011, gross exports in the Day-Ahead Energy Market were 202 percent of gross exports in the Real-Time Energy Market (163 percent for the first six months of 2010). During the first six months of 2011, net interchange was 10,915 GWh in the Day-Ahead Energy Market and -2,949 GWh in the Real-Time Energy Market (-5,490 GWh in the Day-Ahead Energy Market and -3,356 GWh in the Real-Time Energy Market for the first six months of 2010).

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, during the first six months of 2011, there were net exports at eleven of PJM's 21 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 75 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 23 percent, PJM/MidAmerican Energy Company (MEC) with 20 percent, PJM/Cinergy Corporation (CIN) with 17 percent and PJM/Neptune (NEPT) with 15 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 44 percent of the total net PJM exports in the Real-Time Energy Market. Nine PJM interfaces had net imports, with two importing interfaces accounting for 79 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 61 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 18 percent.[3]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, during the first six months of 2011, there were net exports at nine of PJM's 21 interfaces. The top three net exporting interfaces accounted for 72 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 26 percent, PJM/FirstEnergy Corp. (FE) with 25 percent and PJM/NEPT with 21 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND). Combined, these interfaces made up 18 percent of the total net PJM exports in the Day-Ahead Energy Market. Eleven PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 83 percent of the total net imports: PJM/OVEC with 36 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 29 percent and PJM/Michigan Electric Coordinated System (MECS) with 18 percent.[4]

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent Transmission System Operator, Inc. (MISO) Interface Prices.** During the first six 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 six months of 2011, the PJM average hourly

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

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

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

Locational Marginal Price (LMP) at the PJM/MISO border was $34.28 while the MISO LMP at the border was $35.78, a difference of $1.50. While the average hourly LMP difference at the PJM/MISO border was only $1.50, the average of the absolute values of the hourly differences was $12.33. The average hourly flow during the first six months of 2011 was -1,852 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 41 percent of hours during the first six months of 2011. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $16.88. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $9.18. During the first six months of 2011, when the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from PJM to MISO, the average price difference was $16.47. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from MISO to PJM, the average price difference was $22.78. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from MISO to PJM, the average price difference was $23.52. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from PJM to MISO, the average price difference was $8.39.

- **PJM and New York ISO Interface Prices.** During the first six months of 2011, 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. During the first six months of 2011, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. During the first six months of 2011, the PJM average hourly LMP at the PJM/NYISO border was $45.99 while the NYISO LMP at the border was $44.54, a difference of $1.45. While the average hourly LMP difference at the PJM/NYISO border was only $1.45, the average of the absolute value of the hourly difference was $15.40. The average hourly flow during the first six months of 2011 was -552 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) However, the direction of flows was consistent with price differentials in only 53 percent of the hours during the first six months of 2011. During the first six months of 2011, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $13.78. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $17.09. During the first six months of 2011, when the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from PJM to NYISO, the average price difference was $12.21. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from NYISO to PJM, the average price difference was $28.07. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM, the average price difference was $33.29. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from PJM to NYISO, the average price difference was $14.03.

- **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 six 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 six months of 2011, the PJM average hourly LMP at the Neptune Interface was $51.67 while the NYISO LMP at the Neptune Bus was $56.58, a difference of $4.91. While the average hourly LMP difference at the PJM/Neptune border was only $4.91, the average of the absolute value of the hourly difference was $21.37. The average hourly flow during the first six months of 2011 was -472 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 62 percent of the hours during the first six months of 2011. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average pirce difference was $20.75. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $21.39.

- **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 NYISO. A variable frequency transformer allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle regulating transformer.[5] 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 provided that power flows would only be from PJM to New York. On March 31, 2011, PJM, on behalf of Linden VFT, LLC, submitted a revision to Schedule 16 of the PJM Open Access Transmission Tariff which requested the addition of Schedule 16-A to the Tariff to provide the terms and conditions for transmission service on the Linden VFT Facility for imports into PJM.[6] On June 1, 2011, the Tariff revision became effective, allowing for the bidirectional flow across the Linden VFT facility. During the first six 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 six months of 2011, the PJM average hourly LMP at the Linden Interface was $50.99 while the NYISO LMP at the Linden Bus was $53.05, a difference of $2.06. While the average hourly LMP difference at the PJM/Linden border was $2.06, the average of the absolute value of the hourly difference was $19.00. The average hourly flow during the first six months of 2011 was -164 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 during the first six months of 2011. Following June 1, 2011, when bidirectional flows were permitted across the Linden VFT Facility, a total of 100 hours, out of the 720 hours in June, were imports into PJM. Of those 100 hours, 66 hours were economic (i.e. the NYISO/PJM Interface price was lower than the PJM/NYISO Interface price). When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM (66 hours), the average price difference was $43.85. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when power flows were from NYISO to PJM (34 hours), the average price difference was $14.56.

- **Hudson DC Line.** The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line between Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey and Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City with a capacity of 673 MW. The connection will be a submarine AC cable system to interconnect to ConEd. While the Hudson DC line is a bidirectional line, the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights); therefore, power flows will only be from PJM to New York. The current in-service date for this line is January 31, 2012.

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

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[7] 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 NYISO began discussion of a market based congestion management protocol, which continued during the first six months of 2011.

- **PJM and MISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during the first six months of 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. On June 16th, 2011, FERC issued an Order Approving Contested Settlement.[8] This Order approved the settlement submitted by PJM and MISO regarding all issues identified in the complaint proceedings. As part of the Order, FERC also accepted all proposed JOA revisions, subject to PJM submitting a compliance filing, within 15 business days of the Order. On July 1, 2011, PJM and MISO jointly submitted the revisions to the JOA.[9]

7 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) (Accessed August 3, 2011) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (2,285 KB).
8 See 135 FERC ¶ 61,243 (2011).
9 See Docket No. ER11-3979-000 (July 1, 2011).

- **PJM, MISO and TVA Joint Reliability Coordination Agreement.**[10] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of MISO and PJM and the service territory of TVA. The agreement continued to be in effect during the first six months of 2011.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[11] 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 six 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.**[12] 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 six months of 2011, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[13] 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.

10 See "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed August 3, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

11 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) (Accessed August 3, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (642 KB).

12 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed August 3, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

13 See 111 FERC ¶ 61,228 (2005).

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 six months of 2011, net scheduled interchange was -1,623 GWh and net actual interchange was -1,876 GWh for a difference of 253 GWh or 15.6 percent (7.7 percent during the first six months of 2010 and 5.2 percent for the calendar year 2010).

  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 (-8,558 GWh during the first six 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 (2,284 GWh during the first six 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 six 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 497 GWh and the actual flow was 2,781 GWh, a difference of 2,284 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 11 GWh and the actual flow was 4,367 GWh, a difference of 4,356 GWh.

- **PJM Transmission Loading Relief Procedures (TLRs).** During the first six months of 2011, PJM issued 40 TLRs of level 3a or higher. Of the 40 TLRs issued, 21 events were TLR level 3a, and the remaining 19 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 40 TLRs during the first six months of 2011, compared to 58 during the first six months of 2010, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. 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.

- **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.[14] 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 (See Figure 4-18). 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.

  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 1,634 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

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

marginal loss surplus allocation methodology changes (September 17, 2010, through June 30, 2011). (See Figure 4-18.)

Effective May 16, 2011, for the May 17, 2011, Day-Ahead Market, PJM modified the available locations for up-to congestion transactions to eliminate the ability to submit up-to congestion bids at the CPLEIMP, CPLEEXP, DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP Interface pricing points. These interface pricing points were eliminated to avoid wheeling up-to congestion transactions from being submitted at the same interface to arbitrage price differentials between the Day-Ahead and Real-Time Energy Markets created by existing JOA's (for example, using an import pricing point of CPLEIMP and an export pricing point of CPLEEXP or SOUTHEXP). The MMU agrees with the elimination of these interfaces for up-to congestion transactions, as wheeling transactions at the same interface are not permitted in the Real-Time Energy Market.

- **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.

  Total uncollected congestion charges during the first six months of 2011 were $10,790, compared to $1.2 million for the first six 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.

  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 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. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[15] These modifications are currently being evaluated by PJM to develop an implementation plan.

- **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

15 See "Meeting Minutes" Minutes from PJM's MIC meeting (May 16, 2011) (Accessed on August 3, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> 121 KB).

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 six months of 2011, $1.3 million in balancing operating reserve credits were paid due to the uneconomic loading of dispatchable transactions compared to $290,515 during first six months of 2010.

The MMU recommended that dispatchable transactions either be eliminated as a product in the PJM Real-Time Energy Market, or to keep the product, eliminate the operating reserve credits allocated to importing dispatchable transactions and to incorporate the product into the Intermediate Term Security Constrained Economic Dispatch (ITSCED) tool. On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into the ITSCED application.[16] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011.

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.

On June 1, 2011, at 0100, American Transmission System, Inc. was integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduced the total number of external PJM interfaces from 21 to 20 interfaces. Additionally, following the ATSI integration, the MICHFE Interface Pricing Point was eliminated, reducing the total number of interface pricing points from 17 to 16.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first six months of 2011, including evolving transaction patterns, economics and issues. During the first six 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. Four interfaces accounted for 75 percent of the total real-time net exports and two interfaces accounted for 79 percent of the real-time net import volume. Three interfaces accounted for 72 percent of the total day-ahead net exports and three interfaces accounted for 83 percent of the day-ahead net import volume.

During the first six months of 2011, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for many hours,

16 See "Meeting Minutes" Minutes from PJM's MIC meeting (July 13, 2011) (Accessed on August 3, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx> 121 KB).

59 percent between PJM and MISO and 47 percent between PJM and NYISO. The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface flows and 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 June 2011 (See 2010 SOM, Figure 4-1)

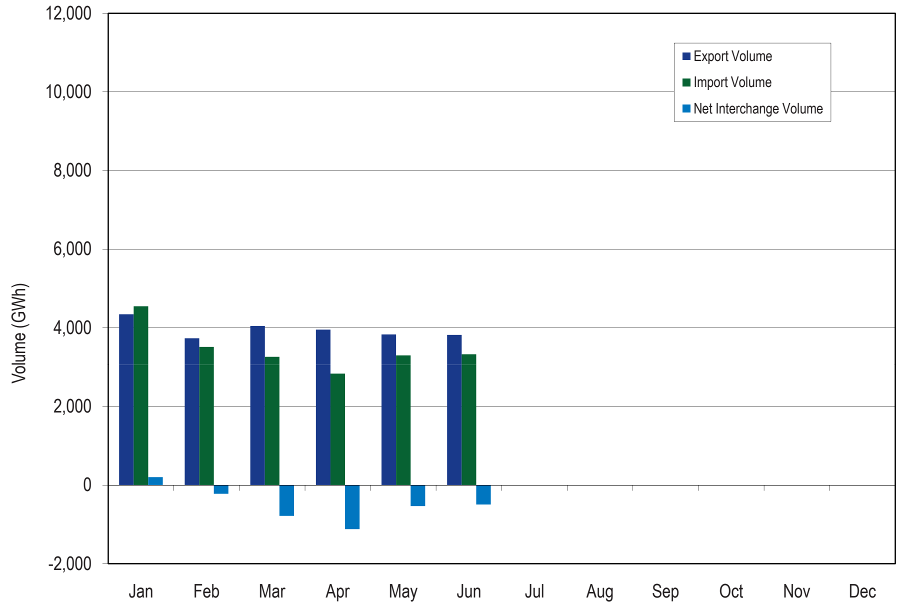


Figure 4-2 PJM day-ahead scheduled imports and exports: January through June 2011 (See 2010 SOM, Figure 4-2)

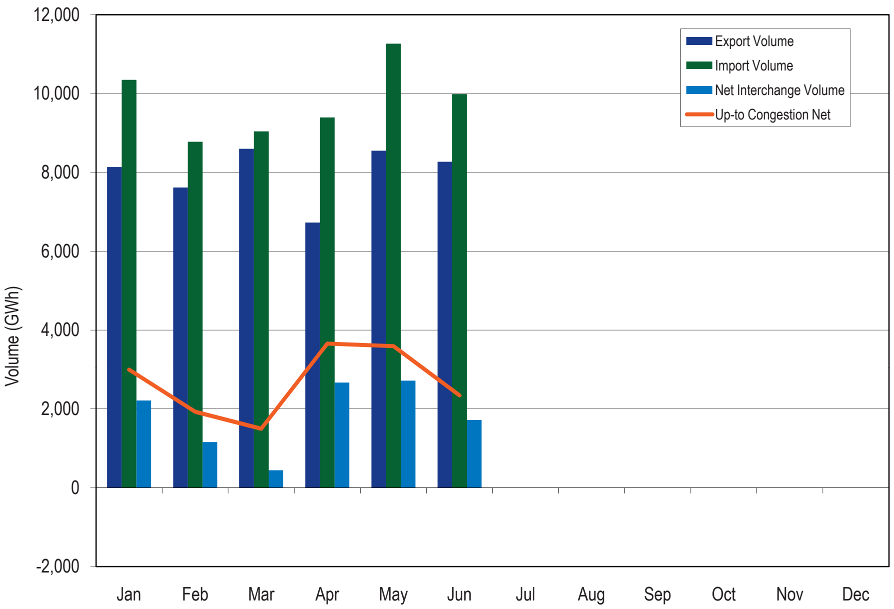


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through June 2011 (See 2010 SOM, Figure 4-3)

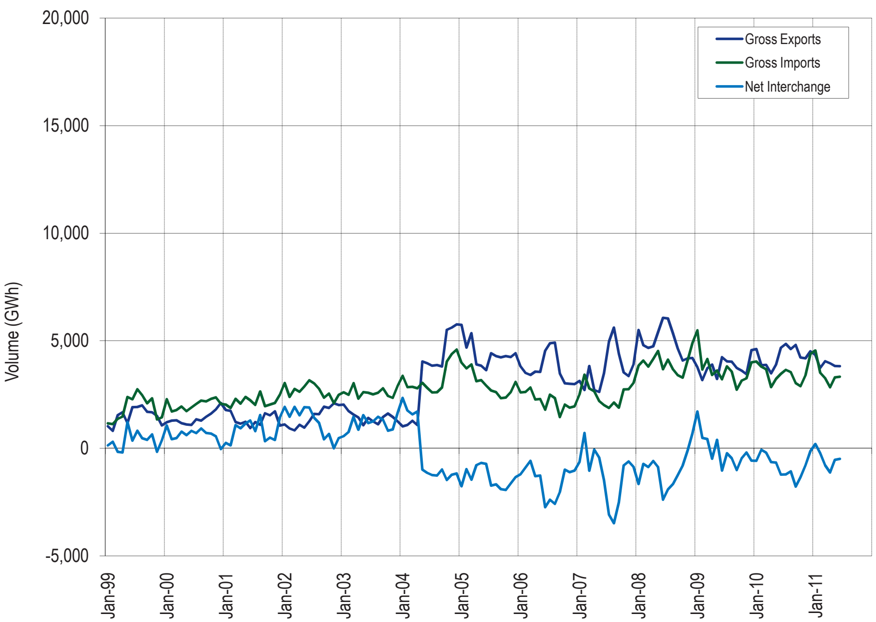
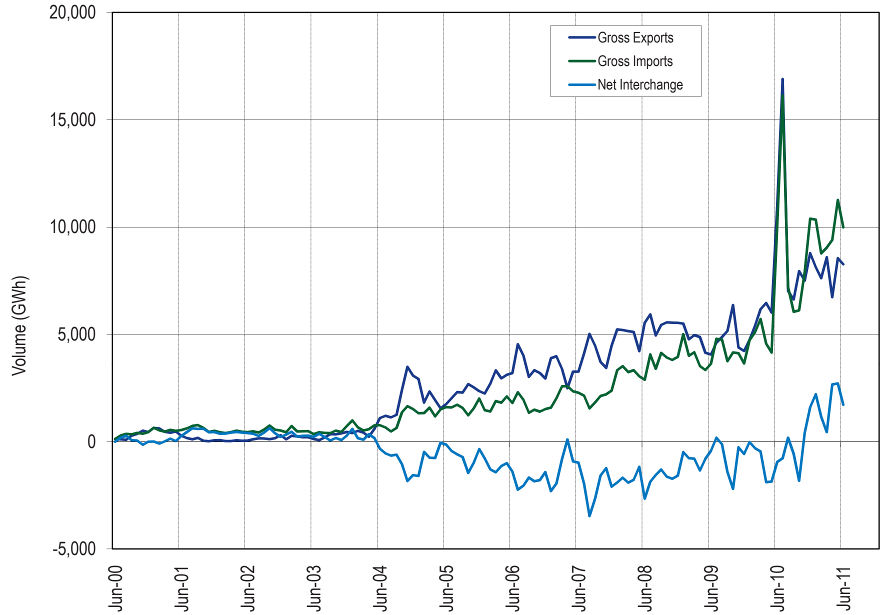


Figure 4-4 PJM scheduled import and export transaction volume history: June 2000 through June 2011 (New Figure)



Interface Imports and Exports

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	(162.6)	(76.3)	(85.5)	(48.3)	(77.6)	(59.1)	(509.4)
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	2.4
DUK	(25.6)	218.7	(17.1)	12.7	34.7	(36.8)	186.6
EKPC	(61.4)	(10.1)	5.6	135.0	41.4	106.4	216.9
LGEE	392.9	385.9	314.6	200.0	241.7	321.8	1,856.9
MEC	(426.0)	(403.3)	(462.2)	(463.2)	(478.5)	(456.3)	(2,689.5)
MISO	(77.3)	(389.0)	(744.4)	(1,131.2)	(495.8)	(675.9)	(3,513.6)
ALTE	(116.1)	(128.3)	(76.0)	(4.5)	(7.6)	(105.7)	(438.2)
ALTW	(30.9)	(14.5)	(28.6)	(49.9)	(68.8)	(83.2)	(275.9)
AMIL	(2.9)	45.5	14.3	8.6	37.9	(17.6)	85.8
CIN	(85.5)	(314.7)	(454.6)	(713.9)	(242.7)	(423.9)	(2,235.3)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	149.9	(43.9)	(159.1)	(250.2)	(251.0)	0.2	(554.1)
IPL	21.8	3.5	8.8	(3.3)	11.0	(12.8)	29.0
MECS	193.0	190.8	112.6	33.2	160.1	128.9	818.6
NIPS	(114.3)	(51.0)	(69.7)	(72.6)	(53.7)	(71.9)	(433.2)
WEC	(92.3)	(76.4)	(92.1)	(78.6)	(81.0)	(89.9)	(510.3)
NYISO	(1,361.0)	(1,279.3)	(1,032.0)	(864.2)	(731.7)	(673.6)	(5,941.8)
LIND	(159.1)	(148.1)	(117.7)	(131.7)	(93.0)	(80.4)	(730.0)
NEPT	(412.9)	(378.8)	(383.7)	(290.8)	(387.5)	(241.0)	(2,094.7)
NYIS	(789.0)	(752.4)	(530.6)	(441.7)	(251.2)	(352.2)	(3,117.1)
OVEC	1,242.2	1,110.7	1,065.8	1,019.0	1,030.7	1,014.6	6,483.0
TVA	681.6	222.8	170.3	19.9	(98.5)	(36.7)	959.4
Total	202.8	(219.9)	(784.9)	(1,120.3)	(533.6)	(493.2)	(2,949.1)

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	6.4	7.4	4.6	6.6	23.4	67.7	116.1
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	2.4
DUK	271.7	309.8	186.2	208.2	197.7	184.4	1,358.0
EKPC	31.7	46.5	41.0	143.3	85.5	112.3	460.3
LGEE	393.0	386.3	324.1	233.6	250.3	334.6	1,921.9
MEC	53.2	30.8	19.1	0.0	0.0	0.0	103.1
MISO	1,141.5	833.9	736.6	409.5	718.2	542.8	4,382.5
ALTE	0.0	0.0	0.0	0.0	0.0	0.2	0.2
ALTW	0.0	0.0	0.0	0.0	0.0	0.9	0.9
AMIL	23.9	68.0	42.2	26.0	55.4	37.8	253.3
CIN	400.0	270.3	315.2	180.8	348.0	260.0	1,774.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	436.8	220.5	122.3	55.5	71.2	0.3	906.6
IPL	25.4	4.8	15.3	5.6	19.3	66.9	137.3
MECS	250.9	270.3	241.4	141.4	224.3	176.7	1,305.0
NIPS	0.0	0.0	0.2	0.2	0.0	0.0	0.4
WEC	4.5	0.0	0.0	0.0	0.0	0.0	4.5
NYISO	681.0	534.7	646.6	686.3	911.4	976.1	4,436.1
LIND	0.0	0.0	0.0	0.0	0.1	14.5	14.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	681.0	534.7	646.6	686.3	911.3	961.6	4,421.5
OVEC	1,242.2	1,110.7	1,091.3	1,019.0	1,030.7	1,014.6	6,508.5
TVA	725.7	255.5	212.0	128.8	79.7	92.0	1,493.7
Total	4,546.4	3,515.6	3,261.5	2,835.3	3,296.9	3,326.9	20,782.6

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	169.0	83.7	90.1	54.9	101.0	126.8	625.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	297.3	91.1	203.3	195.5	163.0	221.2	1,171.4
EKPC	93.1	56.6	35.4	8.3	44.1	5.9	243.4
LGEE	0.1	0.4	9.5	33.6	8.6	12.8	65.0
MEC	479.2	434.1	481.3	463.2	478.5	456.3	2,792.6
MISO	1,218.8	1,222.9	1,481.0	1,540.7	1,214.0	1,218.7	7,896.1
ALTE	116.1	128.3	76.0	4.5	7.6	105.9	438.4
ALTW	30.9	14.5	28.6	49.9	68.8	84.1	276.8
AMIL	26.8	22.5	27.9	17.4	17.5	55.4	167.5
CIN	485.5	585.0	769.8	894.7	590.7	683.9	4,009.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	286.9	264.4	281.4	305.7	322.2	0.1	1,460.7
IPL	3.6	1.3	6.5	8.9	8.3	79.7	108.3
MECS	57.9	79.5	128.8	108.2	64.2	47.8	486.4
NIPS	114.3	51.0	69.9	72.8	53.7	71.9	433.6
WEC	96.8	76.4	92.1	78.6	81.0	89.9	514.8
NYISO	2,042.0	1,814.0	1,678.6	1,550.5	1,643.1	1,649.7	10,377.9
LIND	159.1	148.1	117.7	131.7	93.1	94.9	744.6
NEPT	412.9	378.8	383.7	290.8	387.5	241.0	2,094.7
NYIS	1,470.0	1,287.1	1,177.2	1,128.0	1,162.5	1,313.8	7,538.6
OVEC	0.0	0.0	25.5	0.0	0.0	0.0	25.5
TVA	44.1	32.7	41.7	108.9	178.2	128.7	534.3
Total	4,343.6	3,735.5	4,046.4	3,955.6	3,830.5	3,820.1	23,731.7

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	(11.3)	89.8	126.7	234.5	159.9	(83.0)	516.6
CPLW	17.1	6.4	1.9	11.0	6.0	15.4	57.8
DUK	91.7	115.8	41.0	789.1	234.0	(240.7)	1,030.9
EKPC	(27.5)	(18.4)	27.8	6.8	(5.3)	0.9	(15.7)
LGEE	19.0	1.8	2.0	16.6	35.6	1.8	76.8
MEC	(458.7)	(421.4)	(463.2)	(455.2)	(472.2)	(437.3)	(2,708.0)
MISO	2,144.3	904.6	(182.2)	697.2	452.4	1,481.0	5,497.3
ALTE	1,996.5	908.2	99.1	833.9	1,037.3	1,333.0	6,208.0
ALTW	164.8	(49.7)	(48.1)	(40.1)	(7.3)	139.3	158.9
AMIL	34.6	70.2	67.5	31.0	33.6	(4.6)	232.3
CIN	(125.8)	(90.5)	(175.1)	(94.3)	(18.1)	(131.4)	(635.2)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	(189.4)	(339.7)	(317.2)	(479.3)	(1,299.6)	(1.5)	(2,626.7)
IPL	(175.6)	(162.6)	(163.9)	(75.1)	(123.5)	(97.9)	(798.6)
MECS	742.4	580.2	567.2	591.2	992.5	336.2	3,809.7
NIPS	(280.6)	(111.0)	(130.3)	(65.9)	(108.8)	(90.8)	(787.4)
WEC	(22.6)	99.5	(81.4)	(4.2)	(53.7)	(1.3)	(63.7)
NYISO	(892.0)	(681.9)	(496.7)	(220.9)	611.3	(242.7)	(1,922.9)
LIND	(105.0)	(104.7)	(77.9)	(110.8)	(75.0)	(171.2)	(644.6)
NEPT	(427.9)	(379.7)	(385.0)	(298.1)	(405.2)	(250.0)	(2,145.9)
NYIS	(359.1)	(197.5)	(33.8)	188.0	1,091.5	178.5	867.6
OVEC	1,046.0	1,051.1	1,279.5	1,502.7	1,636.3	1,167.6	7,683.2
TVA	282.8	111.2	106.7	85.9	56.5	55.6	698.7
Total	2,211.4	1,159.0	443.5	2,667.7	2,714.5	1,718.6	10,914.7

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

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	137.6	146.3	197.4	305.0	242.6	29.5	1,058.4
CPLW	19.5	6.5	8.1	13.9	24.6	27.2	99.8
DUK	150.8	155.5	88.5	935.0	269.0	50.9	1,649.7
EKPC	5.4	0.0	28.3	6.8	6.3	2.8	49.6
LGEE	21.6	2.1	13.5	17.1	40.8	41.6	136.7
MEC	21.7	19.8	20.1	8.2	15.9	67.5	153.2
MISO	7,393.7	5,782.6	5,316.8	4,391.0	5,686.9	5,791.8	34,362.8
ALTE	4,872.3	3,576.6	3,109.0	2,156.0	2,959.3	3,808.9	20,482.1
ALTW	375.6	52.1	29.0	19.3	74.1	284.8	834.9
AMIL	44.8	71.1	70.7	34.2	35.8	45.2	301.8
CIN	266.2	440.5	360.6	511.2	263.4	728.0	2,569.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	232.7	140.5	141.0	55.5	17.0	0.0	586.7
IPL	17.0	2.9	0.0	6.5	2.8	1.7	30.9
MECS	1,409.4	1,207.9	1,438.1	1,402.0	2,167.9	772.1	8,397.4
NIPS	32.0	48.2	27.0	33.9	11.6	29.2	181.9
WEC	143.7	242.8	141.4	172.4	155.0	121.9	977.2
NYISO	910.1	988.6	1,149.1	1,399.2	2,467.1	1,560.2	8,474.3
LIND	0.0	0.0	0.0	0.0	0.0	8.7	8.7
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	910.1	988.6	1,149.1	1,399.2	2,467.1	1,551.5	8,465.6
OVEC	1,272.8	1,355.2	1,898.8	1,976.7	2,223.0	1,886.6	10,613.1
TVA	412.1	318.7	318.9	341.8	286.8	529.3	2,207.6
Total	10,345.3	8,775.3	9,039.5	9,394.7	11,263.0	9,987.4	58,805.2

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

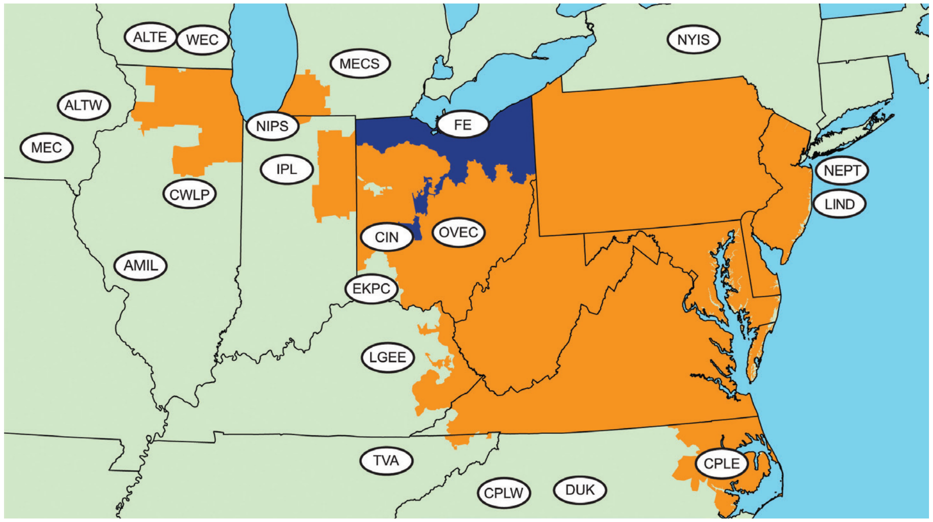
	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	148.9	56.5	70.7	70.5	82.7	112.5	541.8
CPLW	2.4	0.1	6.2	2.9	18.6	11.8	42.0
DUK	59.1	39.7	47.5	145.9	35.0	291.6	618.8
EKPC	32.9	18.4	0.5	0.0	11.6	1.9	65.3
LGEE	2.6	0.3	11.5	0.5	5.2	39.8	59.9
MEC	480.4	441.2	483.3	463.4	488.1	504.8	2,861.2
MISO	5,249.4	4,878.0	5,499.0	3,693.8	5,234.5	4,310.8	28,865.5
ALTE	2,875.8	2,668.4	3,009.9	1,322.1	1,922.0	2,475.9	14,274.1
ALTW	210.8	101.8	77.1	59.4	81.4	145.5	676.0
AMIL	10.2	0.9	3.2	3.2	2.2	49.8	69.5
CIN	392.0	531.0	535.7	605.5	281.5	859.4	3,205.1
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	422.1	480.2	458.2	534.8	1,316.6	1.5	3,213.4
IPL	192.6	165.5	163.9	81.6	126.3	99.6	829.5
MECS	667.0	627.7	870.9	810.8	1,175.4	435.9	4,587.7
NIPS	312.6	159.2	157.3	99.8	120.4	120.0	969.3
WEC	166.3	143.3	222.8	176.6	208.7	123.2	1,040.9
NYISO	1,802.1	1,670.5	1,645.8	1,620.1	1,855.8	1,802.9	10,397.2
LIND	105.0	104.7	77.9	110.8	75.0	179.9	653.3
NEPT	427.9	379.7	385.0	298.1	405.2	250.0	2,145.9
NYIS	1,269.2	1,186.1	1,182.9	1,211.2	1,375.6	1,373.0	7,598.0
OVEC	226.8	304.1	619.3	474.0	586.7	719.0	2,929.9
TVA	129.3	207.5	212.2	255.9	230.3	473.7	1,508.9
Total	8,133.9	7,616.3	8,596.0	6,727.0	8,548.5	8,268.8	47,890.5

Interface Pricing

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

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

Figure 4-5 PJM's footprint and its external interfaces[17] (See 2010 SOM, Figure 4-4)



17 The area in blue on Figure 4-5 shows the region that was incorporated with PJM as part of the ATSI integration that occurred on June 1, 2011 at 0100. Additionally, at that same time, the PJM/First Energy Corp. (FE) Interface was eliminated.

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

PJM 2011 Pricing Points (January through June)						
	Jan	Feb	Mar	Apr	May	Jun
CPLEEXP	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active
MICHFE	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active

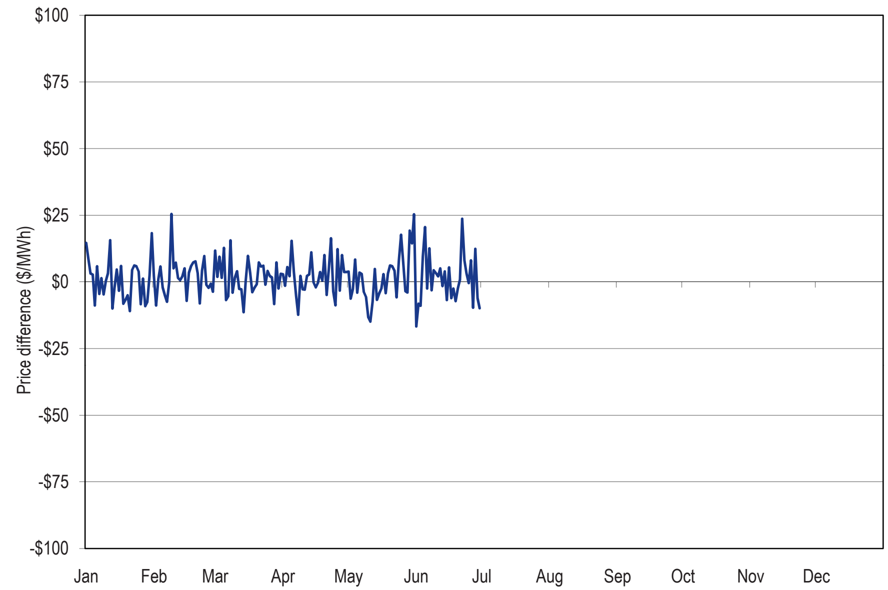
Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

PJM and MISO Interface Prices

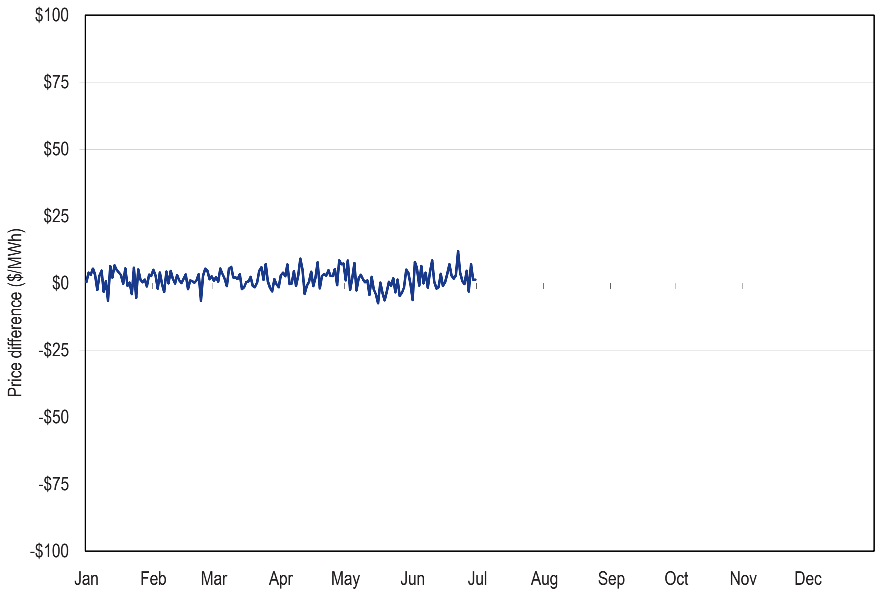
Real-Time Prices

Figure 4-6 Real-time daily hourly average price difference (MISO Interface minus PJM/MISO): January through June 2011 (See 2010 SOM, Figure 4-5)



Day-Ahead Prices

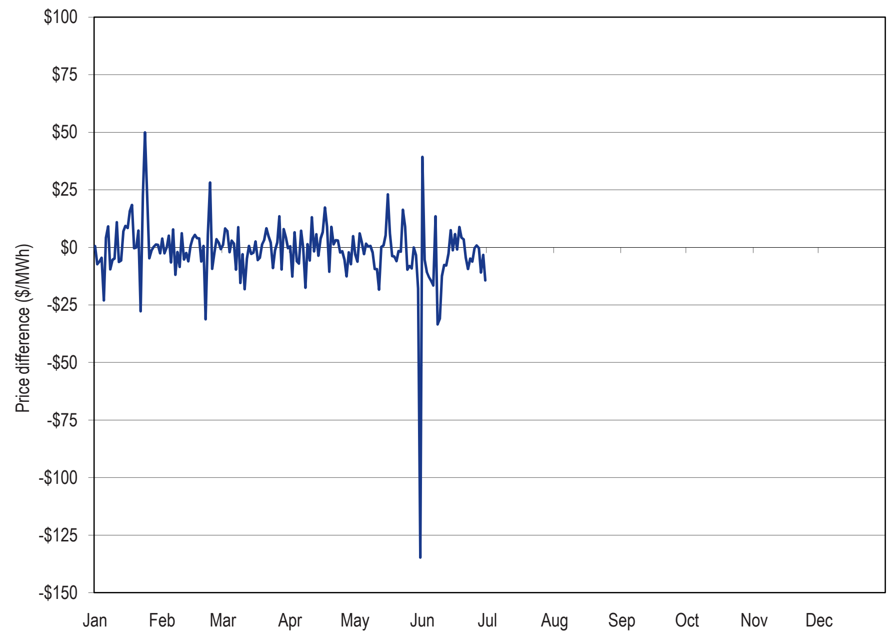
Figure 4-7 Day-ahead daily hourly average price difference (MISO interface minus PJM/MISO): January through June 2011 (See 2010 SOM, Figure 4-6)



PJM and NYISO Interface Prices

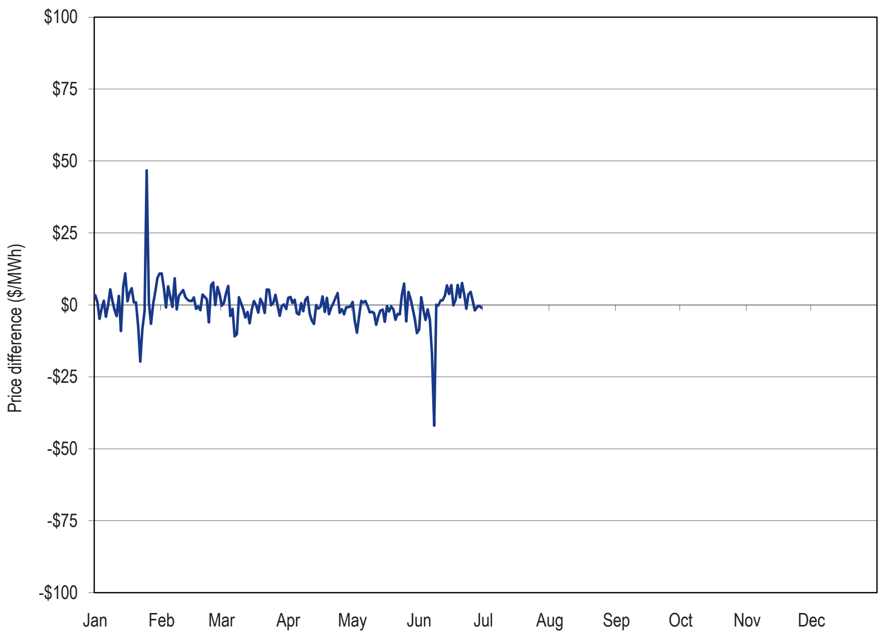
Real-Time Prices

Figure 4-8 Real-time daily hourly average price difference (NY proxy minus PJM/NYIS): January through June 2011 (See 2010 SOM, Figure 4-7)



Day-Ahead Prices

Figure 4-9 Day-ahead daily hourly average price difference (NY proxy minus PJM/NYIS): January through June 2011 (See 2010 SOM, Figure 4-8)



Summary of Interface Prices between PJM and Organized Markets

Figure 4-10 PJM, NYISO and MISO real-time border price averages: January through June 2011 (See 2010 SOM, Figure 4-9)

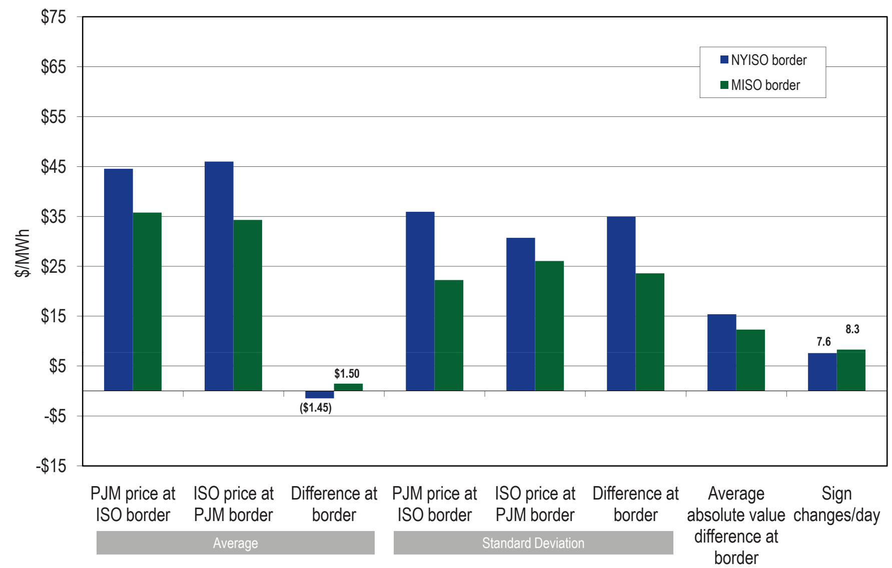
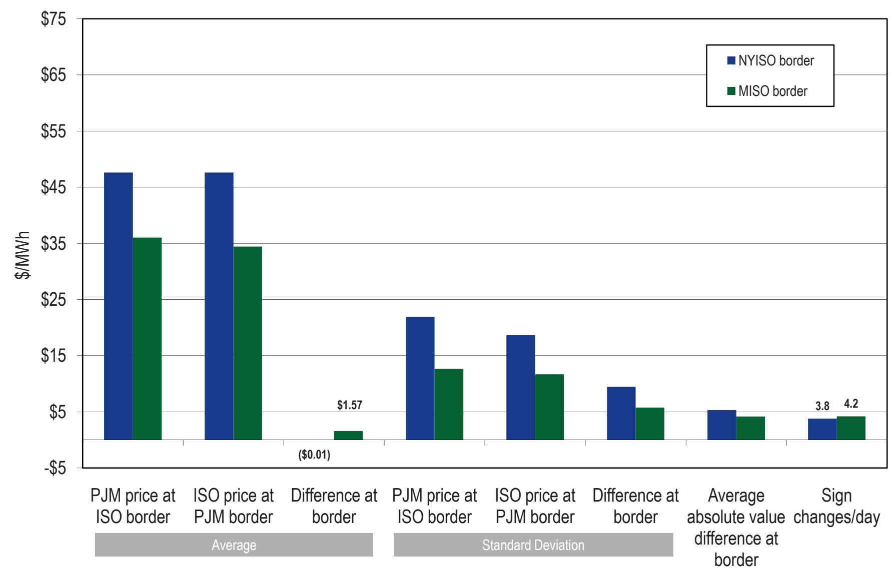
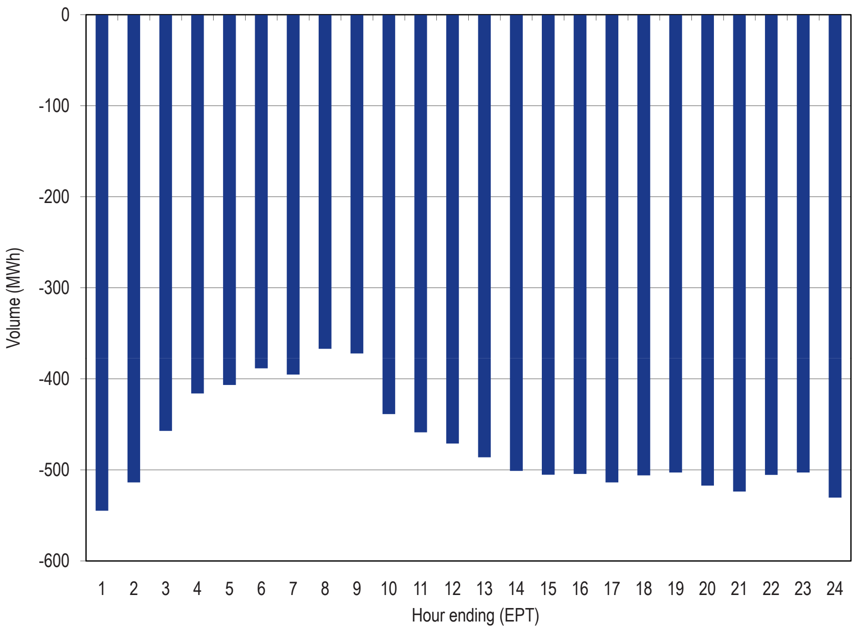


Figure 4-11 PJM, NYISO and MISO day-ahead border price averages: January through June 2011 (See 2010 SOM, Figure 4-10)



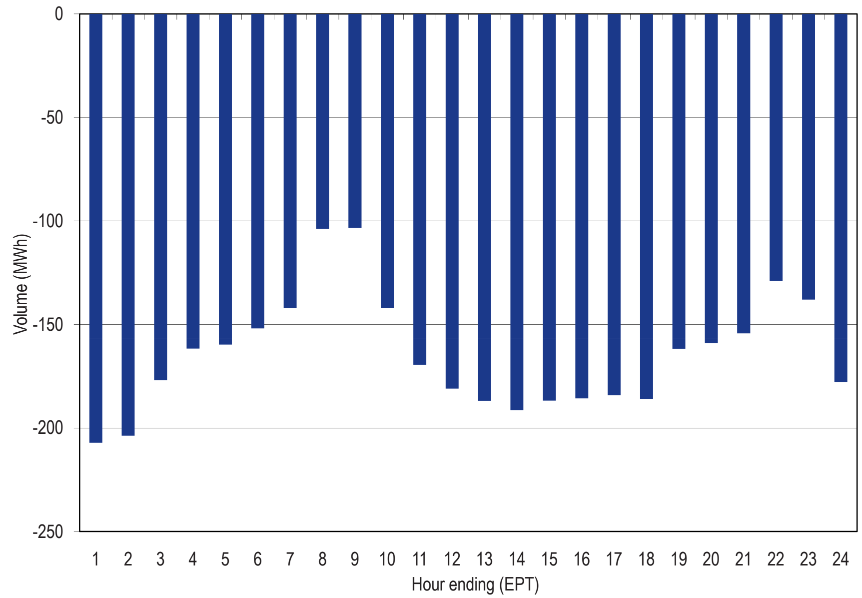
Neptune Underwater Transmission Line to Long Island, New York

Figure 4-12 Neptune hourly average flow: January through June 2011 (See 2010 SOM, Figure 4-11)



Linden Variable Frequency Transformer (VFT) facility

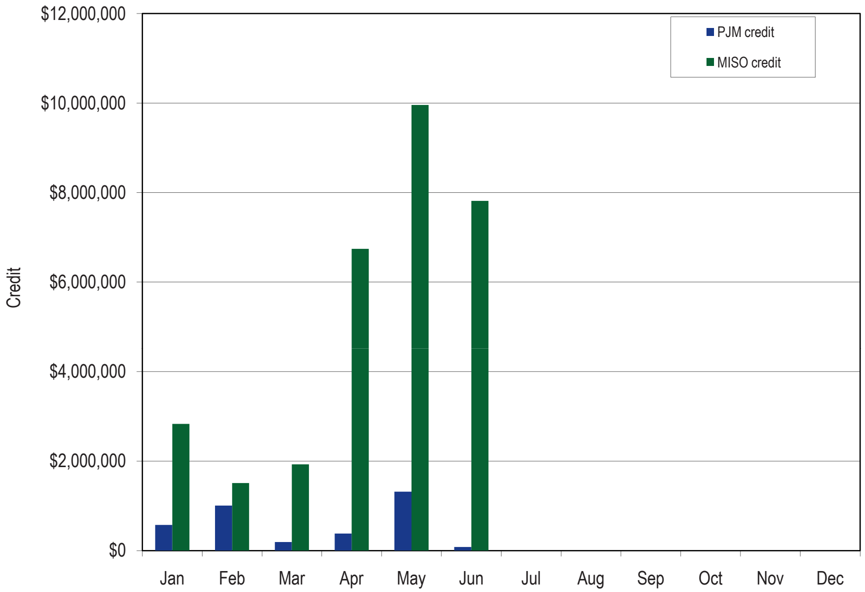
Figure 4-13 Linden hourly average flow: January through June 2011 (See 2010 SOM, Figure 4-12)



Operating Agreements with Bordering Areas

PJM and MISO Joint Operating Agreement

Figure 4-14 Credits for coordinated congestion management: January through June 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 June 2011 (See 2010 SOM, Table 4-9)

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	($1,064,896)	($59)	($1,064,955)	($10,265,822)	$0	($10,265,822)
Congestion Credit			$87,274			($10,433,963)
Adjustments			$15,121			$1,007,268
Net Charge			($1,167,351)			($839,127)

Interchange Transaction Issues

Loop Flows

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

	Actual	Net Scheduled	Difference (GWh)	Difference (Percent of Net Scheduled)
CPLE	4,367	11	4,356	39,600%
CPLW	(900)	2	(902)	(45,100%)
DUK	(1,101)	187	(1,288)	(689%)
EKPC	1,508	217	1,291	595%
LGEE	678	1,857	(1,179)	(63%)
MEC	(863)	(2,685)	1,822	(68%)
MISO	(8,042)	(2,208)	(5,834)	264%
ALTE	(2,900)	(438)	(2,462)	562%
ALTW	(1,009)	(276)	(733)	266%
AMIL	5,754	43	5,711	13,281%
CIN	333	(362)	695	(192%)
CWLP	(82)	-	(82)	0%
FE	(3,464)	(1,005)	(2,459)	245%
IPL	877	(46)	923	(2,007%)
MECS	(7,739)	819	(8,558)	(1,045%)
NIPS	(2,251)	(433)	(1,818)	420%
WEC	2,439	(510)	2,949	(578%)
NYISO	(5,160)	(5,984)	824	(14%)
LIND	(714)	(714)	-	0%
NEPT	(2,050)	(2,050)	-	0%
NYIS	(2,396)	(3,220)	824	(26%)
OVEC	4,856	6,483	(1,627)	(25%)
TVA	2,781	497	2,284	460%
Total	(1,876)	(1,623)	(253)	15.6%

Loop Flows at PJM's Southern Interfaces

Figure 4-15 Southwest actual and scheduled flows: January 2006 through June 2011 (See 2010 SOM, Figure 4-14)

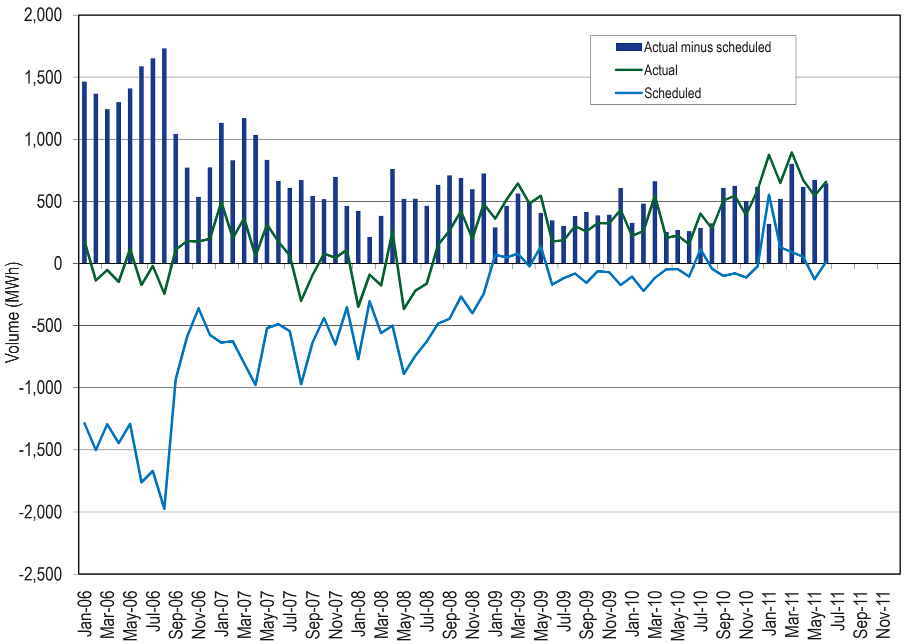
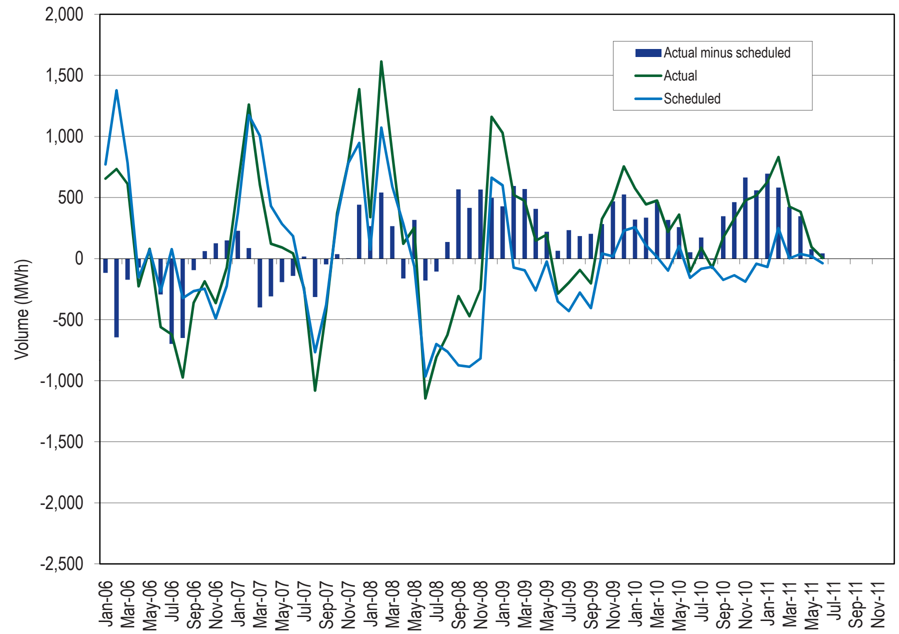


Figure 4-16 Southeast actual and scheduled flows: January 2006 through June 2011 (See 2010 SOM, Figure 4-15)



TLR's

Table 4-11 PJM and MISO TLR procedures: Calendar year 2010 and January through June 2011[18] (See 2010 SOM, Figure 4-16, Figure 4-17 and Figure 4-18)

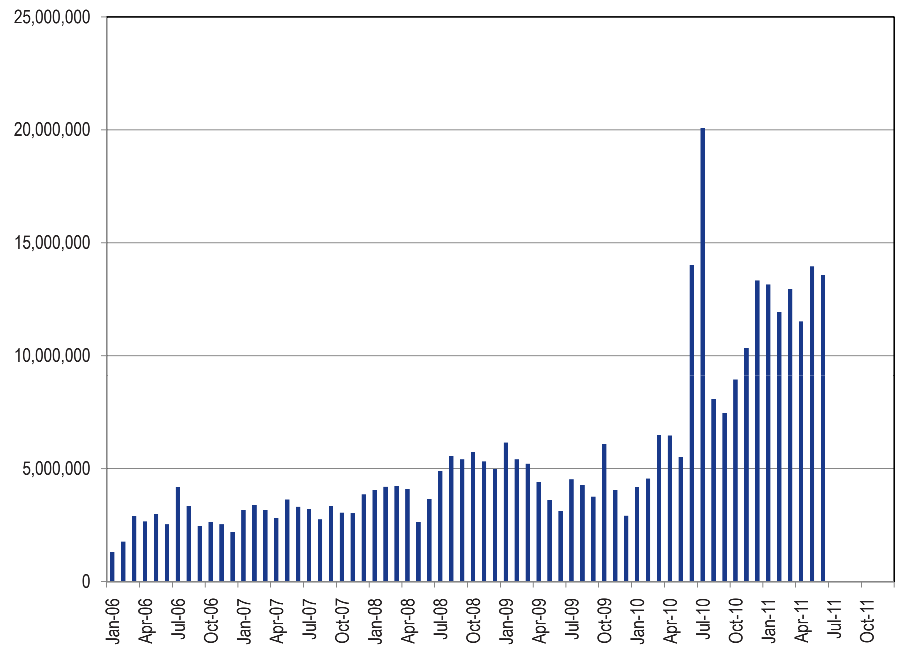
	Number of TLRs Level 3 and Higher		Number of Unique Flowgates That Experienced TLRs		Curtailment Volume (MWh)	
Month	PJM	MISO	PJM	MISO	PJM	MISO
Jan-10	6	23	3	5	18,393	13,387
Feb-10	1	9	1	7	1,249	13,095
Mar-10	6	18	3	10	2,376	27,412
Apr-10	15	40	7	11	26,992	29,832
May-10	11	20	4	12	22,193	54,702
Jun-10	19	19	6	8	64,479	183,228
Jul-10	15	25	8	8	44,210	169,667
Aug-10	12	22	9	7	32,604	189,756
Sep-10	11	15	7	7	82,066	32,782
Oct-10	4	26	3	12	2,305	29,574
Nov-10	1	25	1	10	59	66,113
Dec-10	9	7	6	5	18,509	5,972
Jan-11	7	8	5	5	75,057	14,071
Feb-11	6	7	5	4	6,428	23,796
Mar-11	0	14	0	5	0	10,133
Apr-11	3	23	3	9	8,129	44,855
May-11	9	15	4	7	18,377	36,777
Jun-11	15	14	7	6	17,865	19,437

Table 4-12 Number of TLRs by TLR level by reliability coordinator: January through June 2011 (See 2010 SOM, Table 4-11)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2011	ICTE	14	6	103	29	25	0	177
	MISO	46	23	1	6	5	0	81
	NYIS	119	0	0	0	0	0	119
	ONT	56	0	0	0	0	0	56
	PJM	21	19	0	0	0	0	40
	SWPP	141	170	1	16	15	0	343
	TVA	43	67	3	1	14	0	128
	VACS	9	1	0	0	0	0	10
Total		449	286	108	52	59	0	954

Up-To Congestion

Figure 4-17 Monthly up-to congestion bids in MWh: January 2006 through June 2011 (See 2010 SOM, Figure 4-19)



18 The curtailment volume for PJM TLR's was taken from the individual NERC TLR history reports as posted in the Interchange Distribution Calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLR's was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx.

Figure 4-18 Unique up-to congestion bids with approved MWh: March 2009 through June 2011 (New Figure)

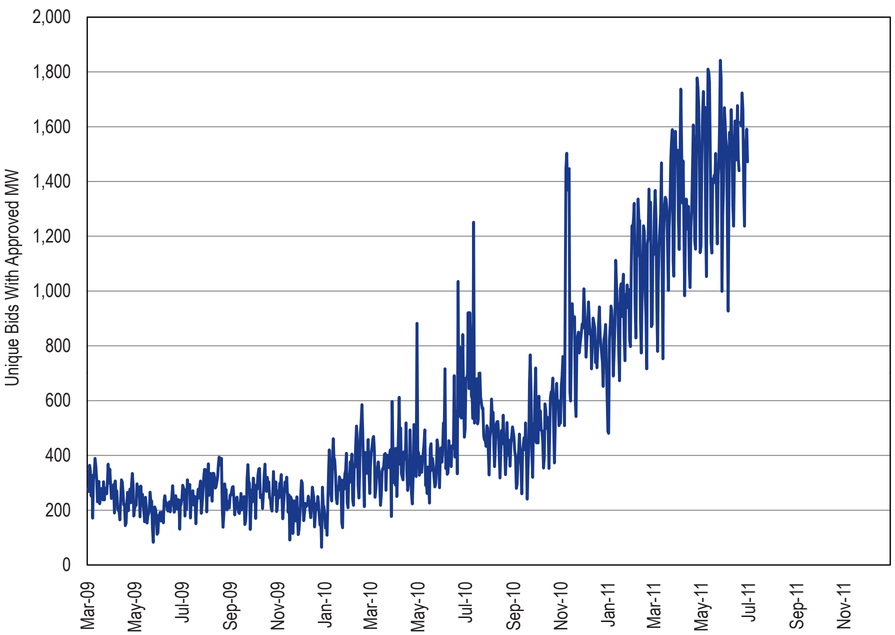


Figure 4-19 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction: January through June 2011 (See 2010 SOM, Figure 4-20)

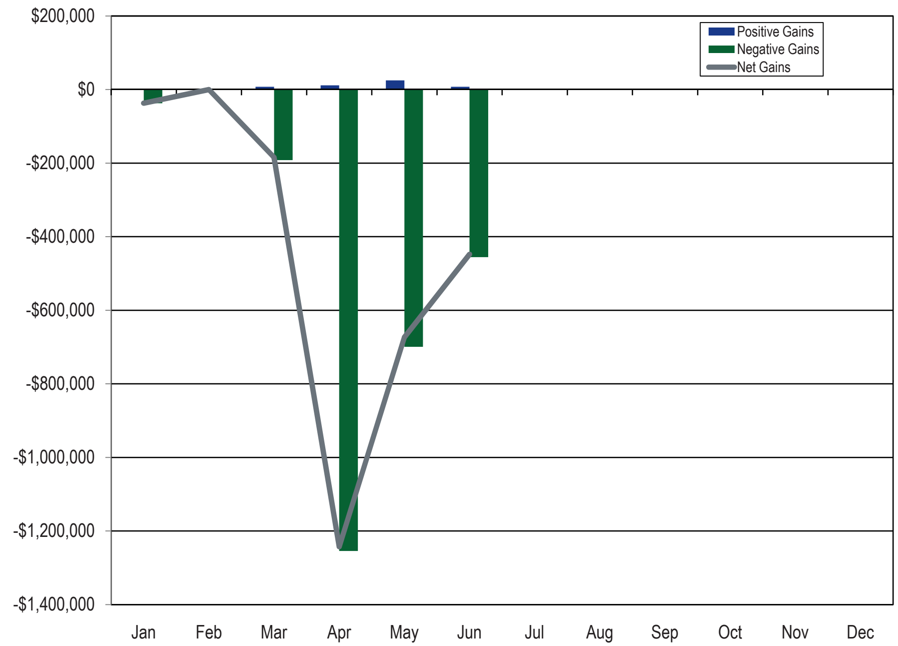


Table 4-13 Up-to congestion MW by Import, Export and Wheels: January through June 2006 through 2011 (See 2010 SOM, Table 4-12)

Jan - Jun	Import MW	Export MW	Wheeling MW	Total MW	Percent Imports	Percent Exports	Percent Wheels
2006	5,089,349	8,836,701	268,269	14,194,319	35.9%	62.3%	1.9%
2007	7,422,198	11,849,133	295,553	19,566,883	37.9%	60.6%	1.5%
2008	7,936,275	14,342,508	630,259	22,909,042	34.6%	62.6%	2.8%
2009	12,144,324	15,028,627	802,512	27,975,462	43.4%	53.7%	2.9%
2010	54,662,719	48,723,549	6,147,957	109,534,225	49.9%	44.5%	5.6%
2011	45,456,976	29,214,227	2,426,526	77,097,729	59.0%	37.9%	3.1%

Figure 4-20 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Energy Market transaction: January through June 2011 (See 2010 SOM, Figure 4-21)

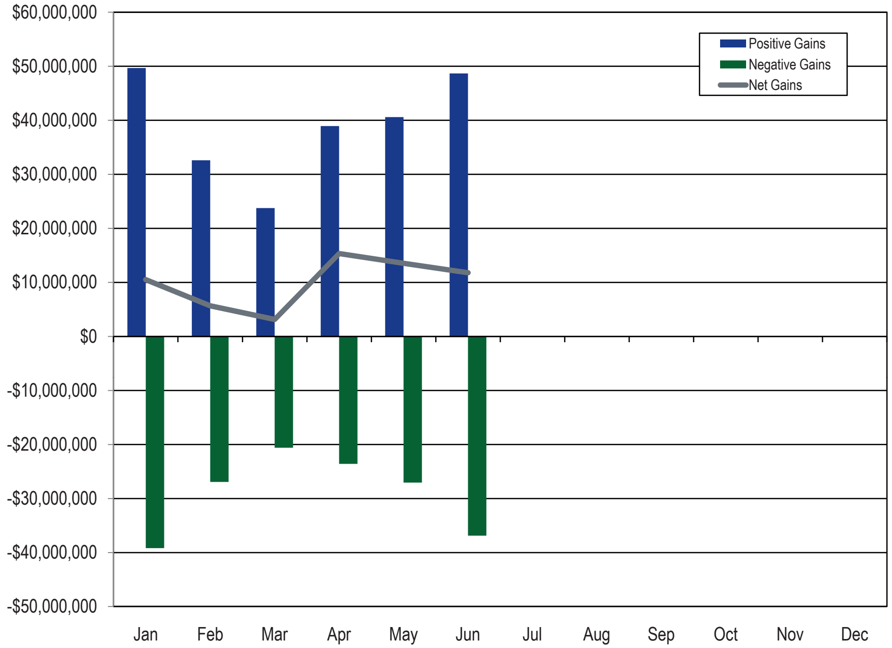


Table 4-15 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through June 2011 (See 2010 SOM, Table 4-14)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$40.87	$42.17	$40.04	$40.04	$0.83	$2.13
PEC	$41.62	$43.98	$40.04	$40.04	$1.58	$3.94
NCMPA	$41.57	$41.78	$40.04	$40.04	$1.53	$1.74

Interface Pricing Agreements with Individual Balancing Authorities

Table 4-14 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through June 2007 through 2011 (See 2010 SOM, Table 4-13)

Jan - Jun	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2007	$52.29	$44.67	$47.71	$46.68	$4.58	($3.04)	$5.61	($2.01)
2008	$64.90	$54.33	$58.07	$58.02	$6.83	($3.74)	$6.88	($3.69)
2009	$39.11	$34.43	$36.07	$36.07	$3.03	($1.64)	$3.03	($1.64)
2010	$43.25	$36.01	$39.03	$38.73	$4.21	($3.02)	$4.51	($2.72)
2011	$43.12	$37.75	$40.04	$40.04	$3.08	($2.29)	$3.08	($2.29)

Figure 4-21 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2011 (See 2010 SOM, Figure 4-22)

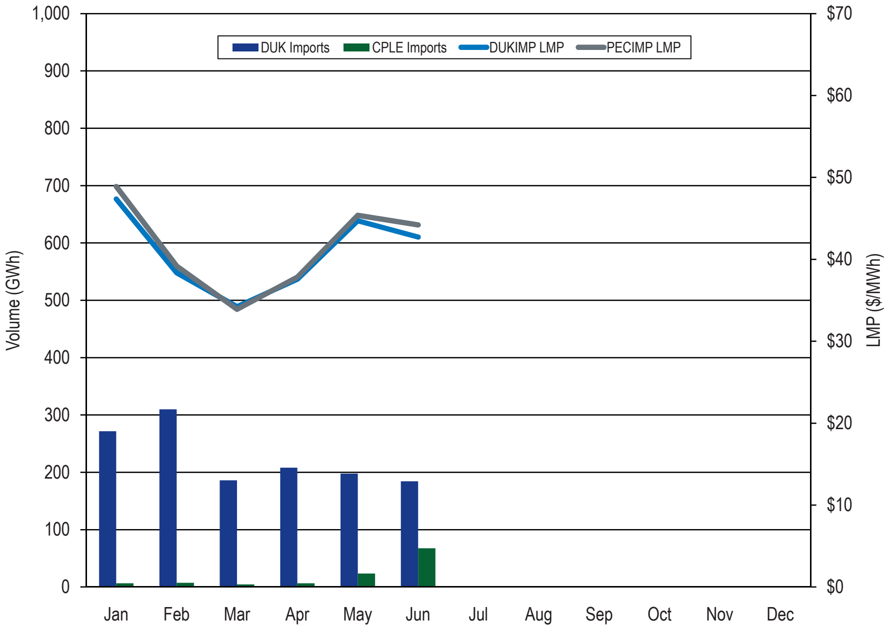


Figure 4-22 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2011 (See 2010 SOM, Figure 4-23)

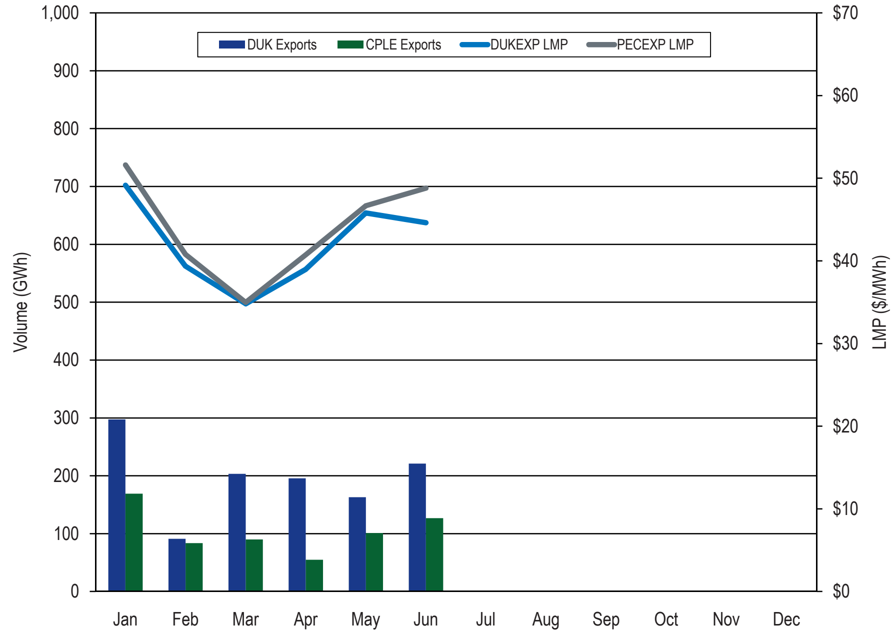


Table 4-16 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through June 2007 through 2011 (See 2010 SOM, Table 4-15)

Jan - Jun	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2007	$51.92	$44.92	$48.05	$46.66	$3.86	($3.13)	$5.25	($1.74)
2008	$66.19	$54.92	$58.97	$58.97	$7.22	($4.05)	$7.22	($4.05)
2009	$39.55	$34.49	$36.29	$36.29	$3.26	($1.80)	$3.26	($1.80)
2010	$44.78	$36.63	$39.40	$39.40	$5.38	($2.77)	$5.38	($2.77)
2011	$43.21	$38.21	$39.88	$39.88	$3.33	($1.67)	$3.33	($1.67)

Table 4-17 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through June 2011 (See 2010 SOM, Table 4-16)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$41.16	$43.11	$39.88	$39.88	$1.27	$3.23
PEC	$41.86	$44.75	$39.88	$39.88	$1.97	$4.87
NCMPA	$41.64	$42.41	$39.88	$39.88	$1.76	$2.52

Figure 4-23 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through June 2011 (See 2010 SOM, Figure 4-24)

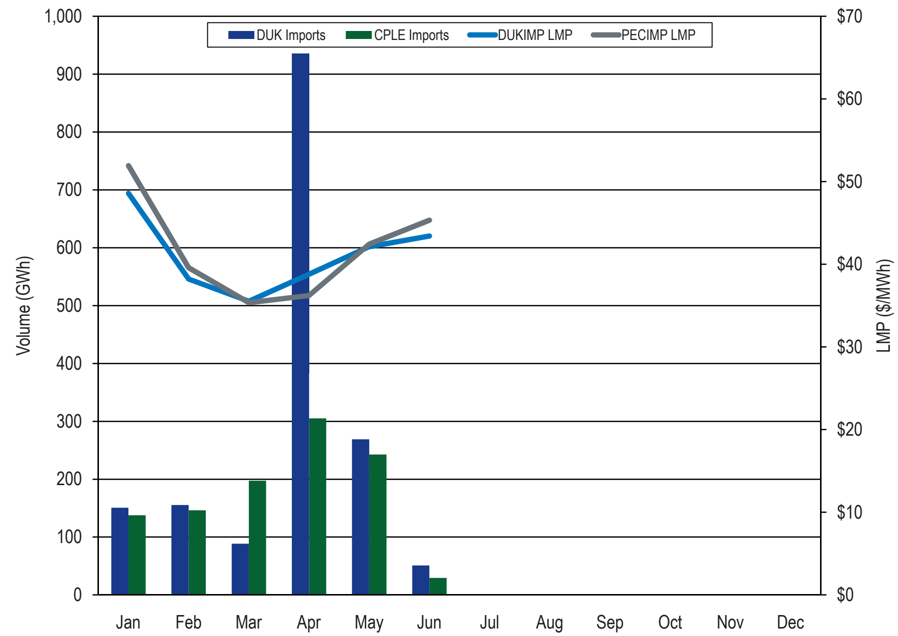
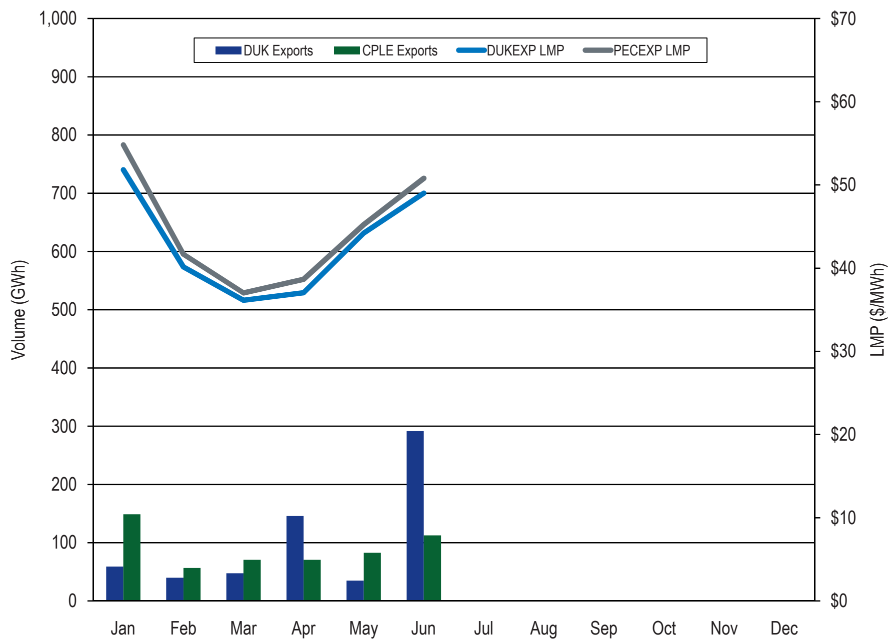
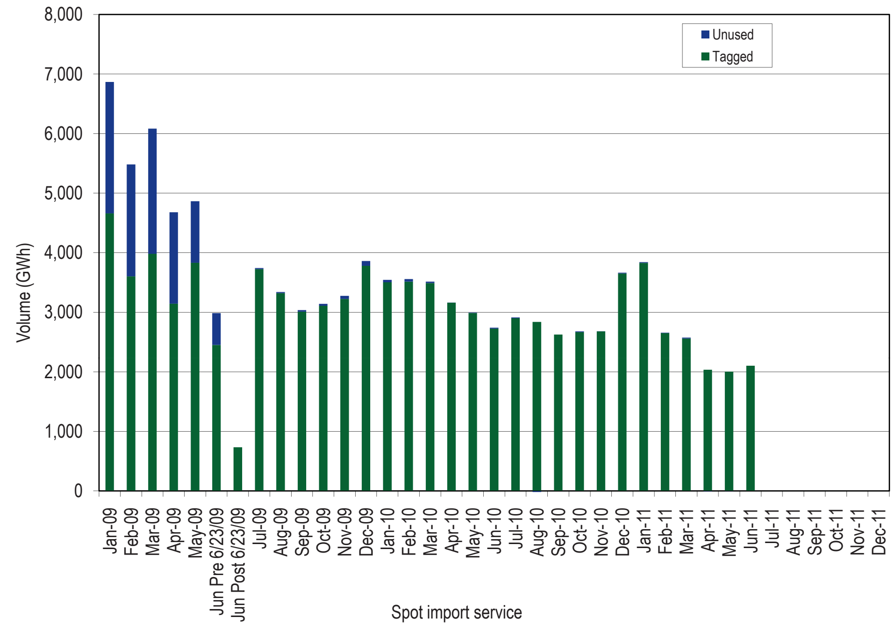


Figure 4-24 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through June 2011 (See 2010 SOM, Figure 4-25)



Spot Import

Figure 4-25 Spot import service utilization: January 2009 through June 2011 (See 2010 SOM, Figure 4-27)



Willing to Pay Congestion and Not Willing to Pay Congestion

Table 4-18 Monthly uncollected congestion charges: Calendar year 2010 and January through June 2011 (See 2010 SOM, Figure 4-26)

Month	2010	2011
Jan	$148,764	$3,102
Feb	$542,575	$1,567
Mar	$287,417	$0
Apr	$31,255	$4,767
May	$41,025	$0
Jun	$169,197	$1,354
Jul	$827,617	
Aug	$731,539	
Sep	$119,162	
Oct	$257,448	
Nov	$30,843	
Dec	$127,176	
Total	$3,314,018	$10,790