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 respond to price differentials. The external regions include both market and non-market balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first nine months of 2014, PJM was a net importer of energy in the Real-Time Energy Market in January, May, June and August, and a net exporter of energy in the remaining five months.[1] During the first nine months of 2014, the real-time net interchange of -982.1 GWh was lower than net interchange of 4,706.7 GWh in the first nine months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first nine months of 2014, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. During the first nine months of 2014, the total day-ahead net interchange of -12,142.4 GWh was lower than net interchange of -12,727.7 GWh during the first nine months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2014, gross imports in the Day-Ahead Energy Market were 113.9 percent of gross imports in the Real-Time Energy Market (150.8 percent during the first nine months of 2013), gross exports in the Day-Ahead Energy Market were 141.5 percent of the gross exports in the Real-Time Energy Market (218.5 percent during the first nine months of 2013).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2014, there were net scheduled exports at 12 of PJM's 18 interface pricing points eligible for real-time transactions.[2]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months of 2014, there were net scheduled exports at 11 of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first nine months of 2014, up-to congestion transactions were net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power 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 the difference between actual and scheduled power flows at one or more specific interfaces.

  For the first nine months of 2014, net scheduled interchange was -1,081 GWh and net actual interchange was -331 GWh, a difference of 750 GWh. For the first nine months of 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh. This difference is inadvertent interchange.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2014, the direction of the average hourly flow was consistent with the real-time

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in 53.0 percent of the hours in the first nine months of 2014.

- **PJM and New York ISO Interface Prices.** In the first nine months of 2014, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 56.0 percent of the hours in the first nine months of 2014.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[3] The direction of flow was consistent with price differentials in 58.9 percent of the hours in the first nine month of 2014.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO Linden Bus.[4] The direction of flow was consistent with price differentials in 56.2 percent of the hours in the first nine months of 2014.
- **Hudson DC Line.** In the first nine months of 2014, the average hourly flow (PJM to NYISO) was inconsistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO Hudson Bus.[5] The direction of flow was consistent with price differentials in 59.3 percent of the hours in the first nine months of 2014.

3 In the first nine months of 2014, there were 590 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $58.04 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.75, a difference of $8.71.

4 In the first nine months of 2014, there were 1,510 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $63.82 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.24, a difference of $2.42.

5 In the first nine months of 2014, there were 4,840 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $111.11 while the NYISO LMP at the Hudson Bus during non-zero flows was $114.83, a difference of $3.72.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued five TLRs of level 3a or higher during the first nine months of 2014, compared to 45 such TLRs issued during the first nine months of 2013.
- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased by 80.1 percent, from 105,472 bids per day in the first nine months of 2013 to 189,997 bids per day in the first nine months of 2014. The average cleared volume of up-to congestion bids increased by 22.6 percent, from 1,221,114 MWh per day in the first nine months of 2013 to 1,496,675 MWh per day in the first nine months of 2014. But the increases all occurred prior to September 8, 2014, after which the number and volume of bids declined sharply.

  On August 29, 2014, FERC issued an Order which, among other things, created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[6] The average number of up-to congestion bids submitted in the Day-Ahead Energy Market decreased by 79.5 percent, from 192,097 bids per day in the three week period prior to the September 8, 2014 refund effective date to 39,429 bids per day in the three week period following the September 8, 2014 refund effective date. The average cleared volume of up-to congestion bids decreased by 79.9 percent, from 1,633,746 MWh per day in the three week period prior to the September 8, 2014 refund effective date to 328,041 MWh per day in the three week period following the September 8, 2014 refund effective date (Figure 9-13).
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule to become compliant with Order No. 764.[7,8] PJM and the MMU issued a statement indicating that both remain concerned about market participants' scheduling behavior, and

6 *Order Instituting Section 206 Proceeding and Establishing Procedures*, 148 FERC ¶ 61,144 (2014).

7 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

8 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

will continue to monitor and address any scheduling behavior that raises operational or market manipulation concerns.[9]

Recommendations

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. New recommendation.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 day-prior to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be utilized to meet load in the most economic manner. (Priority: Medium. New recommendation.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market. (Priority: Medium. New recommendation.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. (Priority: Medium. First reported 2013.)
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling. (Priority: High. First reported 2012.)
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. (Priority: Medium. First reported 2012.)

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.

9 See joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.pjm.com/~/media/documents/reports/20140729-pjm-imm-joint-statement-on-interchange-scheduling.ashx>.

Nonetheless, there are significant differences between market and non-market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and 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's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and generator offers results in an efficient dispatch and efficient prices.

Interchange Transaction Activity

Aggregate Imports and Exports

During the first nine months of 2014, PJM was a monthly net importer of energy in the Real-Time Energy Market in January, May, June and August, and a net exporter of energy in the remaining five months (Figure 9-1).[10] For the first nine months of 2014, the total real-time net interchange of -982.1 GWh was lower than the net interchange of 4,706.7 GWh during the first nine months of 2013. In the first nine months of 2014, the peak month for net importing interchange was January, 1,608.8 GWh; in the first nine months of 2013 it was July, 1,464.4 GWh. Gross monthly export volumes during the first nine months of 2014 averaged 4,439.3 GWh compared to 3,257.1 GWh for the first nine months of 2013, while gross monthly imports in the first nine months of 2014 averaged 4,330.2 GWh compared to 3,780.1 GWh for the first nine months of 2013.

During the first nine months of 2014, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 9-1). In the first nine months of 2014, the total day-ahead net interchange of -12,142.4 GWh was lower than the net interchange of -12,727.7 GWh for the first nine months of 2013. In the first nine months of 2014, the peak month for net exporting interchange was April, -1,992.1 GWh; in the first nine months of 2013 it was January, -2,602.8 GWh. Gross monthly export volumes in the first nine months of 2014 averaged 6,282.3 GWh compared to 7,115.8 GWh for the first nine months of 2013, while gross monthly imports in the first nine months of 2014 averaged 4,933.1 GWh compared to 5,701.6 GWh for the first nine months of 2013.

Figure 9-1 shows the impact of net import and export up-to congestion transactions on the overall net day-ahead energy market interchange. The import, export and net interchange volumes include fixed, dispatchable and up-to congestion transaction totals. The up-to congestion net volume (as represented by the line on the chart) shows the net up-to congestion transaction volume. The net interchange volume under the line in Figure 9-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

In the first nine months of 2014, gross imports in the Day-Ahead Energy Market were 113.9 percent of gross imports in the Real-Time Energy Market (150.8 percent for the first nine months of 2013), gross exports in the Day-Ahead Energy Market were 141.5 percent of gross exports in the Real-Time Energy Market (218.5 percent for the first nine months of 2013). In the first nine months of 2014, net interchange was -12,142.4 GWh in the Day-Ahead Energy Market and -982.1 GWh in the Real-Time Energy Market compared to -12,727.7 GWh in the Day-Ahead Energy Market and 4,706.7 GWh in the Real-Time Energy Market for the first nine months of 2013.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MW and price differences in the Day-Ahead and Real-Time Energy Markets.[11] In the first nine months of 2014, while the total day-ahead imports and exports were greater than the real-time imports and exports, the day-ahead imports net of up-to congestion transactions were less than the real-time imports, and the day-ahead exports net of up-to congestion transactions were less than real-time exports.

10 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

11 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: January through September, 2014

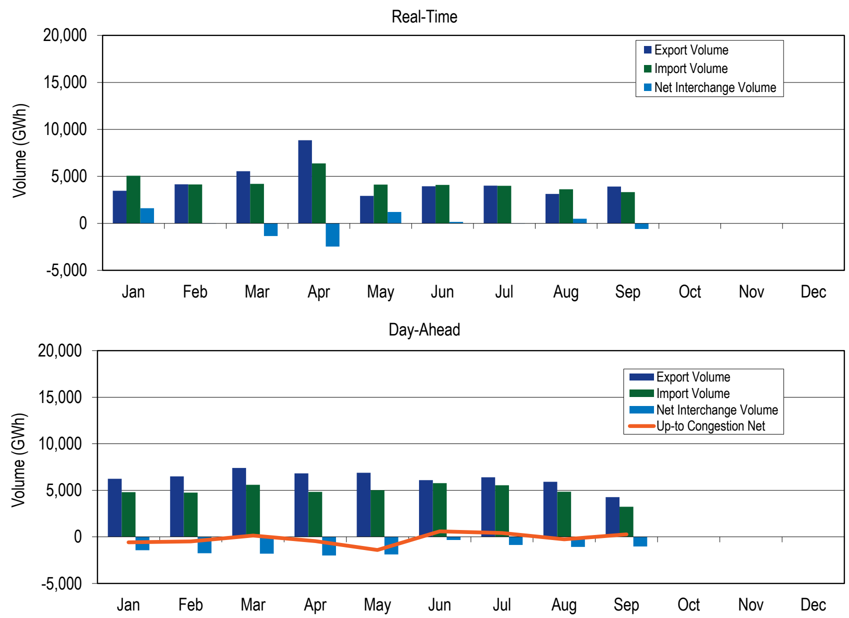
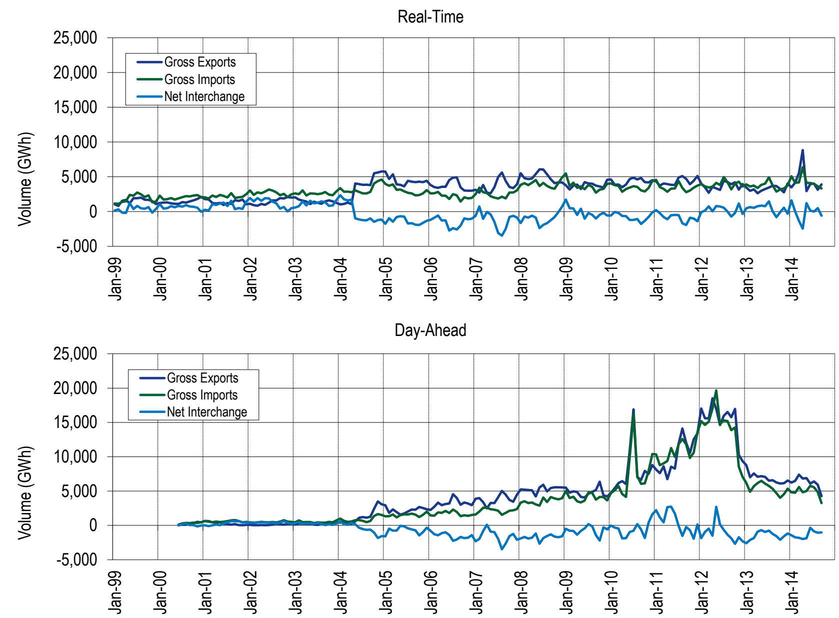


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through June 2014. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint caused by the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM's operation. In January 2012, the direction of real-time power flows began to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Energy Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased. While the gross import and export volumes in the Day-Ahead Energy Market have decreased, the net direction of power flows has remained predominantly in the export direction.

Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through September, 2014



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. See Table 9-16 for a list of active interfaces during the first nine months of 2014. Figure 9-3 shows the approximate geographic location of the interfaces. In the first nine months of 2014, PJM had 20 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. Similarly, there are nine separate interfaces that make up the MISO Interface between the PJM and MISO. Table 9-1 through Table 9-3 show the Real-Time Energy Market interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net interchange in the Real-Time Energy Market is shown by interface for the first nine months of 2014 in Table 9-1, while gross imports and exports are shown in Table 9-2 and Table 9-3.

In the Real-Time Energy Market, in the first nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 58.8 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 22.7 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 18.4 percent and PJM/Neptune (NEPT) with 17.8 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 37.0 percent of the total net PJM exports in the Real-Time Energy Market. Seven PJM interfaces had net scheduled imports, with three importing interfaces accounting for 81.6 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 40.6 percent, PJM/Ameren-Illinois (AMIL) with 28.6 percent and PJM/Tennessee Valley Authority (TVA) with 12.4 percent of the net import volume.[12]

Eleven shareholders own the generation located in the OVEC footprint and share OVEC's generation output. Approximately 80 percent of OVEC is owned by load serving entities or their affiliates located in the PJM footprint. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires delivery of approximately 80 percent of the generation output into the PJM footprint.[13]

12 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).
13 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (October 15, 2014).

Table 9-1 Real-time scheduled net interchange volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(33.5)	(11.2)	(12.8)	(43.8)	(31.3)	37.3	(24.2)	(17.7)	(32.1)	(169.4)
CPLW	0.0	0.6	5.2	0.0	0.0	0.0	0.0	0.0	0.0	5.8
DUK	294.7	395.5	541.7	214.6	183.8	(37.1)	(135.1)	(114.3)	(41.3)	1,302.6
LGEE	262.4	230.3	159.5	99.7	129.6	233.3	182.1	207.7	182.3	1,687.1
MEC	(421.8)	(387.0)	(239.8)	(829.9)	(512.5)	(611.3)	(606.6)	(607.8)	(658.8)	(4,875.3)
MISO	1,193.0	(460.9)	(1,620.2)	(1,670.7)	453.8	(90.4)	188.9	684.8	(523.7)	(1,845.4)
ALTE	(140.8)	(241.9)	(770.7)	(1,032.8)	(361.5)	(412.4)	(290.0)	(199.4)	(501.5)	(3,950.8)
ALTW	(49.5)	(85.5)	(98.5)	(219.6)	(8.1)	(8.7)	(4.0)	(0.5)	(39.5)	(513.9)
AMIL	917.6	478.4	317.9	792.1	566.6	576.5	791.0	764.2	667.5	5,871.9
CIN	318.9	(341.6)	(350.1)	(527.8)	(32.6)	15.2	9.5	16.8	(132.5)	(1,024.1)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	87.3	(65.3)	(2.3)	27.0	7.1	(222.1)	(75.2)	6.7	(58.7)	(295.4)
MECS	158.2	(25.4)	(564.6)	(774.2)	140.3	(41.1)	(31.4)	134.1	(363.7)	(1,368.0)
NIPS	15.2	(51.6)	(3.7)	224.5	266.0	179.3	(4.1)	53.3	93.8	772.7
WEC	(113.8)	(128.0)	(148.3)	(159.9)	(124.0)	(177.2)	(207.1)	(90.4)	(189.2)	(1,337.8)
NYISO	(1,091.2)	(1,328.3)	(1,701.2)	(1,783.0)	(15.6)	(410.0)	(635.3)	(547.5)	(434.5)	(7,946.6)
HUDS	(79.2)	(210.2)	(98.9)	(0.2)	(2.6)	(5.9)	(9.6)	(3.9)	(33.7)	(444.2)
LIND	(72.8)	(134.8)	(117.6)	(96.2)	69.9	7.3	5.0	(14.3)	(27.9)	(381.5)
NEPT	(303.6)	(424.0)	(390.7)	(870.7)	(256.7)	(369.9)	(426.6)	(462.1)	(310.5)	(3,814.7)
NYIS	(635.5)	(559.4)	(1,094.0)	(816.0)	173.9	(41.5)	(204.1)	(67.2)	(62.4)	(3,306.2)
OVEC	1,055.5	990.6	972.3	1,169.3	631.7	875.9	911.9	841.7	866.2	8,315.1
TVA	349.8	552.2	545.5	380.7	368.7	153.0	102.7	42.3	49.1	2,544.0
Total	1,608.8	(18.3)	(1,349.8)	(2,463.0)	1,208.3	150.7	(15.5)	489.3	(592.7)	(982.1)

Table 9-2 Real-time scheduled gross import volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	0.7	5.1	2.4	7.8	0.8	76.0	4.6	1.3	0.0	98.5
CPLW	0.0	0.6	5.2	0.0	0.0	0.0	0.0	0.0	0.0	5.8
DUK	355.0	427.5	563.5	401.3	310.3	196.6	166.9	148.7	157.0	2,726.8
LGEE	263.5	230.3	162.7	140.9	130.9	233.9	182.5	208.1	185.8	1,738.6
MEC	16.5	0.2	226.2	1.9	0.0	0.0	2.9	0.0	0.0	247.7
MISO	1,922.9	1,066.3	918.6	2,597.1	1,668.9	1,523.0	1,568.0	1,362.4	1,177.5	13,804.8
ALTE	55.0	9.3	0.3	1.5	1.4	0.3	75.2	1.0	1.5	145.5
ALTW	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
AMIL	967.4	627.9	486.4	1,068.4	619.9	615.6	829.8	807.1	694.2	6,716.7
CIN	517.5	160.6	176.7	550.9	327.3	303.7	254.5	124.9	97.5	2,513.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	141.4	44.7	166.9	278.8	165.0	121.1	128.4	87.5	66.5	1,200.2
MECS	215.2	219.9	85.1	430.1	287.3	301.4	278.0	288.6	224.0	2,329.5
NIPS	25.9	3.9	0.9	267.2	267.8	180.9	2.1	53.3	93.8	895.8
WEC	0.0	0.0	2.4	0.2	0.2	0.0	0.2	0.1	0.1	3.1
NYISO	1,022.4	838.9	773.7	1,623.0	984.6	993.4	1,005.4	936.3	830.5	9,008.2
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	23.2	5.2	5.8	3.3	82.5	25.8	46.7	18.0	18.1	228.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	999.1	833.6	767.9	1,619.8	902.2	967.5	958.7	918.3	812.5	8,779.6
OVEC	1,082.6	1,016.0	995.4	1,204.8	649.7	892.8	929.3	859.3	883.0	8,512.8
TVA	413.4	559.8	549.5	401.2	385.8	182.7	140.2	107.6	88.0	2,828.1
Total	5,076.9	4,144.7	4,197.2	6,378.0	4,131.0	4,098.3	3,999.8	3,623.7	3,321.9	38,971.5

Table 9-3 Real-time scheduled gross export volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	34.2	16.3	15.2	51.6	32.0	38.7	28.8	19.0	32.1	267.9
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	60.3	32.0	21.8	186.6	126.5	233.8	302.0	263.0	198.3	1,424.3
LGEE	1.1	0.0	3.2	41.1	1.3	0.5	0.4	0.4	3.6	51.5
MEC	438.3	387.1	466.0	831.8	512.5	611.3	609.5	607.8	658.8	5,123.0
MISO	729.9	1,527.2	2,538.8	4,267.8	1,215.1	1,613.4	1,379.2	677.6	1,701.2	15,650.2
ALTE	195.9	251.2	771.0	1,034.3	362.9	412.7	365.1	200.3	502.9	4,096.2
ALTW	50.1	85.5	98.5	219.6	8.1	8.7	4.0	0.5	39.5	514.4
AMIL	49.8	149.6	168.5	276.3	53.3	39.1	38.8	42.9	26.7	844.8
CIN	198.6	502.1	526.7	1,078.7	359.9	288.4	245.0	108.2	230.0	3,537.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	54.1	110.0	169.2	251.8	157.8	343.2	203.6	80.8	125.2	1,495.6
MECS	57.1	245.3	649.7	1,204.4	147.0	342.5	309.4	154.5	587.6	3,697.5
NIPS	10.7	55.5	4.6	42.7	1.8	1.6	6.2	0.0	0.0	123.1
WEC	113.8	128.0	150.7	160.1	124.2	177.2	207.2	90.4	189.3	1,341.0
NYISO	2,113.6	2,167.2	2,475.0	3,406.1	1,000.2	1,403.3	1,640.7	1,483.8	1,265.0	16,954.8
HUDS	79.2	210.2	98.9	0.2	2.6	5.9	9.6	3.9	33.7	444.2
LIND	96.1	140.0	123.4	99.4	12.6	18.5	41.8	32.3	46.0	610.1
NEPT	303.6	424.0	390.7	870.7	256.7	369.9	426.6	462.1	310.5	3,814.7
NYIS	1,634.7	1,393.0	1,862.0	2,435.8	728.3	1,009.1	1,162.7	985.5	874.9	12,085.9
OVEC	27.1	25.5	23.0	35.5	18.1	16.9	17.4	17.5	16.7	197.8
TVA	63.6	7.6	4.0	20.5	17.0	29.6	37.5	65.4	38.9	284.1
Total	3,468.0	4,163.0	5,546.9	8,841.0	2,922.7	3,947.6	4,015.3	3,134.4	3,914.6	39,953.6

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which scheduled imports or exports will flow.[14] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the

14 A market path is the scheduled path rather than the actual path on which power flows. A market path contains the generation balancing authority, all required transmission segments and the load balancing authority. There are multiple market paths between any generation and load balancing authority. Market participants select the market path based on transmission service availability and the transmission costs for moving energy from generation to load.

GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the MISO/PJM Interface based on the scheduled market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the MISO/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[15]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[16] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. According to the *PJM Interface Price Definition Methodology*, dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[17] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. Table 9-17 presents the interface pricing points used in the first nine months of 2014.

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

16 See "Interface Pricing Point Assignment Methodology," (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx> (Accessed October 16, 2014). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

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

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally. The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The result of such behavior can be incorrect pricing of transactions.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[18]

In the Real-Time Energy Market, in the first nine months of 2014, there were net scheduled exports at 12 of PJM's 18 interface pricing points eligible for

18 The MMU does not believe that it is appropriate to allow the use of the Southwest pricing point for the grandfathered transactions, and suggests that no further such agreements be entered into.

real-time transactions.[19] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 87.4 percent of the total net exports: PJM/MISO with 64.6 percent, PJM/Neptune (NEPT) with 13.1 percent and PJM/NYIS with 9.7 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 25.7 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 81.0 percent of the total net imports: PJM/SouthIMP with 51.4 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 29.6 percent of the net import volume.

Table 9-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	(79.2)	(210.2)	(98.9)	(0.2)	(2.6)	(5.9)	(9.6)	(3.9)	(33.7)	(444.2)
IMO	390.9	171.2	227.6	955.3	525.8	476.6	531.5	403.6	300.5	3,983.1
LINDENVFT	(72.8)	(134.8)	(117.6)	(96.2)	69.9	7.3	5.0	(14.3)	(27.9)	(381.5)
MISO	(817.2)	(1,772.6)	(2,939.2)	(4,872.8)	(1,493.6)	(1,979.0)	(1,736.5)	(1,021.0)	(2,120.9)	(18,752.8)
NEPTUNE	(303.6)	(424.0)	(390.7)	(870.7)	(256.7)	(369.9)	(426.6)	(462.1)	(310.5)	(3,814.7)
NORTHWEST	(0.4)	(0.7)	(2.7)	(116.8)	(103.3)	(140.1)	(134.9)	(133.2)	(132.6)	(764.6)
NYIS	(548.6)	(414.6)	(997.0)	(771.4)	152.6	(19.0)	(173.0)	(18.3)	(25.3)	(2,814.7)
OVEC	1,055.5	990.6	972.3	1,169.3	631.7	875.9	911.9	841.7	866.2	8,315.1
SOUTHIMP	2,145.9	1,840.7	2,040.8	2,440.9	1,862.3	1,607.7	1,386.5	1,259.1	1,165.0	15,748.8
CPLEIMP	0.4	0.0	0.1	7.8	0.3	71.3	0.0	0.0	0.0	79.8
DUKIMP	101.2	216.8	106.6	90.1	32.6	42.1	32.6	33.8	30.1	685.9
NCMPAIMP	96.3	113.1	113.1	73.7	50.5	14.6	39.8	42.3	34.8	578.2
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,948.0	1,510.7	1,820.9	2,269.3	1,779.0	1,479.7	1,314.1	1,183.0	1,100.1	14,404.9
SOUTHEXP	(161.5)	(63.9)	(44.4)	(300.5)	(177.7)	(302.8)	(369.8)	(362.5)	(273.6)	(2,056.7)
CPLEEXP	(31.0)	(16.2)	(14.6)	(50.8)	(31.7)	(28.7)	(22.8)	(13.5)	(32.1)	(241.5)
DUKEXP	(32.3)	(22.3)	(14.9)	(141.5)	(97.7)	(163.1)	(112.5)	(48.9)	(80.2)	(713.5)
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
SOUTHEAST	(2.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.7)
SOUTHWEST	(2.4)	(7.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(9.4)
SOUTHEXP	(93.2)	(18.4)	(14.9)	(108.2)	(48.2)	(110.9)	(234.5)	(300.1)	(161.2)	(1,089.5)
Total	1,608.8	(18.3)	(1,349.8)	(2,463.0)	1,208.3	150.7	(15.5)	489.3	(592.7)	(982.1)

Table 9-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IMO	447.2	222.9	260.3	965.1	525.9	477.8	534.3	405.3	311.2	4,150.0
LINDENVFT	23.2	5.2	5.8	3.3	82.5	25.8	46.7	18.0	18.1	228.6
MISO	341.1	123.6	57.0	109.3	129.8	104.0	113.4	115.6	95.7	1,189.5
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	1,036.9	935.0	834.9	1,654.6	880.8	988.9	987.0	966.4	849.0	9,133.5
OVEC	1,082.6	1,016.0	995.4	1,204.8	649.7	892.8	929.3	859.3	883.0	8,512.8
SOUTHIMP	2,145.9	1,841.9	2,043.8	2,440.9	1,862.3	1,609.1	1,389.1	1,259.1	1,165.0	15,757.1
CPLEIMP	0.4	0.0	0.1	7.8	0.3	71.3	0.0	0.0	0.0	79.8
DUKIMP	101.2	216.8	106.6	90.1	32.6	42.1	32.6	33.8	30.1	685.9
NCMPAIMP	96.3	113.1	113.1	73.7	50.5	14.6	39.8	42.3	34.8	578.2
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,948.0	1,511.9	1,824.0	2,269.3	1,779.0	1,481.1	1,316.7	1,183.0	1,100.1	14,413.1
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	5,076.9	4,144.7	4,197.2	6,378.0	4,131.0	4,098.3	3,999.8	3,623.7	3,321.9	38,971.5

19 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

Table 9-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	79.2	210.2	98.9	0.2	2.6	5.9	9.6	3.9	33.7	444.2
IMO	56.3	51.7	32.6	9.8	0.1	1.2	2.8	1.7	10.7	166.9
LINDENVFT	96.1	140.0	123.4	99.4	12.6	18.5	41.8	32.3	46.0	610.1
MISO	1,158.3	1,896.2	2,996.2	4,982.2	1,623.4	2,083.0	1,849.9	1,136.6	2,216.6	19,942.3
NEPTUNE	303.6	424.0	390.7	870.7	256.7	369.9	426.6	462.1	310.5	3,814.7
NORTHWEST	0.4	0.7	2.7	116.8	103.3	140.1	134.9	133.2	132.6	764.6
NYIS	1,585.5	1,349.7	1,832.0	2,426.0	728.3	1,007.9	1,160.0	984.7	874.2	11,948.2
OVEC	27.1	25.5	23.0	35.5	18.1	16.9	17.4	17.5	16.7	197.8
SOUTHIMP	0.0	1.2	3.0	0.0	0.0	1.4	2.6	0.0	0.0	8.2
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	1.2	3.0	0.0	0.0	1.4	2.6	0.0	0.0	8.2
SOUTHEXP	161.5	63.9	44.4	300.5	177.7	302.8	369.8	362.5	273.6	2,056.7
CPLEEXP	31.0	16.2	14.6	50.8	31.7	28.7	22.8	13.5	32.1	241.5
DUKEXP	32.3	22.3	14.9	141.5	97.7	163.1	112.5	48.9	80.2	713.5
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7
SOUTHWEST	2.4	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4
SOUTHEXP	93.2	18.4	14.9	108.2	48.2	110.9	234.5	300.1	161.2	1,089.5
Total	3,468.0	4,163.0	5,546.9	8,841.0	2,922.7	3,947.6	4,015.3	3,134.4	3,914.6	39,953.6

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than in the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[20] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow unless they are also submitted in the Real-Time Energy Market. In the Day-Ahead Energy Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up-to congestion; and dispatchable.[21]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. In Table 9-7, Table 9-8 and Table 9-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, a market participant may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM. If the market participant knows that the source of the energy in the Real-Time Market will be associated with the SouthIMP interface pricing point, they may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Energy Market. In the interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP interface pricing point, which reflects the expected power flow.

Table 9-7 through Table 9-9 show the day-ahead interchange totals at the individual interfaces. Net interchange in the Day-Ahead Energy Market is shown by interface for the first nine months of 2014 in Table 9-7, while gross imports and exports are shown in Table 9-8 and Table 9-9.

In the Day-Ahead Energy Market, in the first nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 68.7 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 25.5 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 23.1 percent and PJM/Neptune (NEPT) with 20.1 percent of the net export

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

21 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 45.2 percent of the total net PJM exports in the Day-Ahead Energy Market. The nine separate interfaces that connect PJM to MISO together represented 27.9 percent of the total net PJM exports in the Day-Ahead Energy Market. Six PJM interfaces had net scheduled imports, with two importing interfaces accounting for 96.4 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 82.3 percent, and PJM/DUK with 14.1 percent of the net import volume.[22]

Table 9-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(30.1)	(15.5)	(13.9)	(20.2)	(25.2)	15.7	(22.4)	(12.5)	(24.9)	(149.0)
CPLW	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
DUK	151.9	128.5	270.6	116.8	152.3	73.5	42.0	8.6	9.0	953.1
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	(433.6)	(375.5)	(438.5)	(230.5)	(505.0)	(587.7)	(608.6)	(605.8)	(595.6)	(4,380.8)
MISO	(137.8)	(528.3)	(1,069.7)	(898.3)	(277.0)	(477.1)	(512.8)	(135.5)	(748.9)	(4,785.4)
ALTE	(96.1)	(148.5)	(516.3)	(439.3)	(263.1)	(315.0)	(311.1)	(167.5)	(396.2)	(2,653.1)
ALTW	(7.3)	(18.8)	(13.8)	(9.9)	0.0	0.0	(3.5)	0.0	(36.2)	(89.4)
AMIL	25.4	81.2	27.2	(17.0)	(7.5)	(20.0)	(16.7)	(1.3)	5.1	76.4
CIN	(31.5)	(209.0)	(221.1)	(179.5)	37.7	84.4	(23.5)	(5.7)	(46.4)	(594.6)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	87.1	0.0	(28.3)	(21.2)	(7.2)	(1.2)	(4.9)	24.3
MECS	75.0	(113.1)	(360.3)	(180.8)	86.1	(51.9)	40.9	126.8	(82.5)	(459.8)
NIPS	0.0	(45.2)	0.0	(6.9)	0.0	0.0	(4.4)	0.0	0.0	(56.4)
WEC	(103.4)	(74.9)	(72.5)	(64.8)	(101.9)	(153.4)	(187.4)	(86.6)	(187.9)	(1,032.7)
NYISO	(1,140.8)	(1,230.9)	(1,482.8)	(988.0)	(285.5)	(594.6)	(834.2)	(667.4)	(534.3)	(7,758.4)
HUDS	(45.7)	(141.5)	(77.2)	0.0	(0.6)	(0.8)	(1.0)	0.0	(20.0)	(286.7)
LIND	(10.2)	(22.3)	(15.8)	(11.7)	5.4	5.5	(4.1)	(1.5)	(3.8)	(58.6)
NEPT	(280.3)	(437.6)	(430.2)	(445.9)	(260.4)	(378.2)	(434.5)	(467.5)	(317.9)	(3,452.5)
NYIS	(804.6)	(629.4)	(959.6)	(530.4)	(29.9)	(221.1)	(394.6)	(198.4)	(192.6)	(3,960.6)
OVEC	727.2	728.3	733.3	439.0	451.0	634.3	642.8	616.9	597.2	5,569.9
TVA	8.8	29.3	55.2	35.1	13.6	4.5	6.9	(16.7)	6.3	143.0
Total without Up-To Congestion	(854.4)	(1,263.4)	(1,945.9)	(1,546.1)	(475.7)	(931.4)	(1,286.3)	(812.4)	(1,291.4)	(10,407.0)
Up-To Congestion	(578.5)	(482.9)	143.1	(446.1)	(1,399.6)	598.5	423.1	(260.6)	267.6	(1,735.4)
Total	(1,433.0)	(1,746.3)	(1,802.8)	(1,992.1)	(1,875.3)	(332.9)	(863.2)	(1,073.0)	(1,023.8)	(12,142.4)

22 In the Day-Ahead Energy Market, two PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP) and PJM/LG&E Energy Transmission Services (LGEE)).

Table 9-8 Day-Ahead scheduled gross import volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	0.0	0.0	0.0	3.2	0.0	40.9	0.0	0.0	0.0	44.1
CPLW	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
DUK	157.5	128.5	270.6	125.7	153.2	95.6	85.7	63.6	49.5	1,129.9
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.8	2.8
MISO	152.3	127.1	150.7	219.8	283.2	247.9	146.2	203.2	286.7	1,817.1
ALTE	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.9	32.9
ALTW	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
AMIL	25.4	88.7	45.4	0.0	0.0	0.0	0.0	0.1	5.5	165.1
CIN	26.1	0.0	0.0	114.4	151.8	122.8	41.8	15.3	6.4	478.7
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	87.1	0.0	0.0	0.0	0.0	0.0	0.0	87.1
MECS	99.4	38.4	15.9	105.4	131.4	125.1	104.4	187.8	242.9	1,050.7
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	0.0	0.0	2.3	0.0	0.0	0.0	0.0	0.0	0.0	2.3
NYISO	679.5	611.9	610.9	629.3	684.3	771.1	761.1	753.4	644.5	6,146.1
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	3.6	2.6	3.5	1.1	11.0	15.7	8.3	5.1	6.5	57.4
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	675.9	609.4	607.4	628.2	673.3	755.4	752.8	748.3	638.0	6,088.6
OVEC	727.3	728.3	733.3	439.0	467.2	651.2	660.2	632.5	635.0	5,673.9
TVA	29.7	29.3	55.2	35.1	20.5	12.8	10.4	2.0	21.0	215.9
Total without Up-To Congestion	1,746.2	1,625.7	1,820.7	1,452.1	1,608.4	1,819.6	1,663.6	1,654.7	1,639.4	15,030.4
Up-To Congestion	3,054.9	3,127.2	3,778.6	3,384.6	3,397.8	3,948.4	3,877.9	3,194.9	1,603.4	29,367.6
Total	4,801.1	4,752.9	5,599.2	4,836.7	5,006.1	5,768.0	5,541.5	4,849.6	3,242.8	44,398.0

Table 9-9 Day-Ahead scheduled gross export volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	30.1	15.5	13.9	23.4	25.2	25.2	22.4	12.5	24.9	193.1
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	5.6	0.0	0.0	8.8	0.9	22.1	43.8	55.0	40.5	176.7
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	433.6	375.5	438.5	230.5	505.0	587.7	608.6	605.8	598.4	4,383.6
MISO	290.1	655.3	1,220.4	1,118.1	560.1	725.0	659.0	338.8	1,035.6	6,602.5
ALTE	97.2	148.5	516.3	439.3	263.1	315.0	311.1	167.5	428.1	2,686.1
ALTW	7.6	18.8	13.8	9.9	0.0	0.0	3.5	0.0	36.2	89.7
AMIL	0.0	7.5	18.3	17.0	7.5	20.0	16.7	1.4	0.3	88.6
CIN	57.6	209.0	221.1	293.9	114.1	38.4	65.3	21.0	52.8	1,073.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	28.3	21.2	7.2	1.2	4.9	62.8
MECS	24.4	151.5	376.2	286.2	45.3	177.0	63.6	61.0	325.4	1,510.6
NIPS	0.0	45.2	0.0	6.9	0.0	0.0	4.4	0.0	0.0	56.4
WEC	103.4	74.9	74.8	64.8	101.9	153.4	187.4	86.6	187.9	1,035.0
NYISO	1,820.3	1,842.8	2,093.7	1,617.3	969.7	1,365.7	1,595.3	1,420.8	1,178.8	13,904.4
HUDS	45.7	141.5	77.2	0.0	0.6	0.8	1.0	0.0	20.0	286.7
LIND	13.8	24.9	19.3	12.9	5.6	10.2	12.5	6.6	10.3	116.0
NEPT	280.3	437.6	430.2	445.9	260.4	378.2	434.5	467.5	317.9	3,452.5
NYIS	1,480.5	1,238.8	1,567.0	1,158.6	703.2	976.6	1,147.3	946.7	830.6	10,049.2
OVEC	0.1	0.0	0.0	0.0	16.2	16.9	17.4	15.6	37.9	104.0
TVA	20.9	0.0	0.0	0.0	6.9	8.4	3.5	18.6	14.7	73.0
Total without Up-To Congestion	2,600.6	2,889.1	3,766.6	2,998.2	2,084.1	2,751.1	2,949.9	2,467.1	2,930.8	25,437.4
Up-To Congestion	3,633.4	3,610.2	3,635.5	3,830.6	4,797.4	3,349.9	3,454.7	3,455.5	1,335.8	31,103.0
Total	6,234.0	6,499.3	7,402.0	6,828.8	6,881.5	6,101.0	6,404.7	5,922.6	4,266.6	56,540.4

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-10 through Table 9-15 show the Day-Ahead Energy Market interchange totals at the individual interface pricing points. In the first nine months of 2014, up-to congestion transactions accounted for 66.1 percent of all scheduled import MW transactions, 55.0 percent of all scheduled export MW transactions and 14.3 percent of the net interchange volume in the Day-Ahead Energy Market. Net interchange in the Day-Ahead Energy Market, including up-to congestion transactions, is shown by interface pricing point in the first nine months of 2014 in Table 9-10. Up-to congestion transactions by interface pricing point in the first nine months of 2014 are shown in Table 9-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Energy Market are shown in Table 9-12 and Table 9-14, while gross import up-to congestion transactions are show in Table 9-13 and gross export up-to congestion transactions are shown in Table 9-15.

There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO). The NIPSCO interface pricing point was created when the individual balancing authorities that integrated to form MISO operated independently. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the formation of the MISO RTO, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-Time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO. The NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market to facilitate the long term day-ahead positions created at the NIPSCO Interface prior to the integration.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006. After the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. The Southeast pricing point also remains eligible to receive the real-time interface price only through the reserve sharing agreement with VACAR. The grandfathered agreements for the Southeast interface pricing point have expired. The Southeast interface pricing point remains an eligible interface pricing point in the PJM Day-

Ahead Energy Market to facilitate the long term day-ahead positions created prior to the consolidation of the Southeast and Southwest interface pricing points.

The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point.

In the Day-Ahead Energy Market, in the first nine months of 2014, there were net scheduled exports at 11 of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 53.7 percent of the total net exports: PJM/SouthEXP with 23.8 percent, PJM/MISO with 16.1 percent and PJM/Southwest with 13.8 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 24.6 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interface pricing points had net imports, with three importing interface pricing points accounting for 80.6 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 36.4 percent, PJM/Southeast with 22.4 percent and PJM/SouthIMP with 21.7 percent of the net import volume.

In the Day-Ahead Energy Market, in the first nine months of 2014, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points for up-to congestion transactions accounted for 91.5 percent of the total net up-to congestion exports: PJM/SouthEXP with 44.0 percent, PJM/Southwest with 26.5 percent and PJM/NIPSCO with 21.0 percent of the net export up-to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 2.1 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/Linden with 1.2 percent and PJM/NEPTUNE with 0.9 percent). The PJM/NYIS, and PJM/HUDS interface pricing points had net imports in the Day-Ahead Energy Market. Seven PJM interface pricing points had net up-to congestion imports, with three importing interface pricing points accounting for 57.8 percent of the total net up-to congestion imports: PJM/Southeast with 24.0 percent, PJM/MISO with 18.6 percent and PJM/Northwest with 15.1 percent of the net import volume.[23]

Table 9-10 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	(19.6)	(8.6)	68.1	107.5	174.9	178.8	285.0	336.6	(8.6)	1,114.1
IMO	319.5	296.7	271.0	169.4	68.5	148.6	196.9	305.2	193.9	1,969.7
LINDENVFT	(72.0)	(69.4)	(0.6)	(77.5)	(31.6)	(54.4)	58.7	13.9	8.4	(224.4)
MISO	(442.9)	(648.2)	(977.1)	(823.7)	(384.9)	(57.5)	(157.1)	50.3	(763.5)	(4,204.6)
NEPTUNE	(353.8)	(396.7)	(433.3)	(437.3)	(353.3)	(422.7)	(429.6)	(427.3)	(318.2)	(3,572.2)
NIPSCO	(763.3)	(19.3)	(274.5)	(630.7)	(616.1)	(33.9)	(242.9)	(172.1)	(119.2)	(2,872.0)
NORTHWEST	24.1	134.8	(36.0)	140.9	(376.9)	(704.4)	(561.0)	(536.6)	(482.4)	(2,397.5)
NYIS	(755.3)	(510.8)	(912.7)	(460.5)	131.1	31.3	(39.2)	(48.7)	(82.2)	(2,647.0)
OVEC	1,225.6	54.0	599.1	140.3	227.2	976.7	652.2	200.2	628.7	4,703.9
SOUTHIMP	641.1	834.2	1,639.1	1,129.2	1,247.2	1,184.5	889.3	828.0	637.3	9,029.9
CPLEIMP	0.0	0.6	0.0	3.2	0.0	40.9	0.0	0.0	0.0	44.7
DUKIMP	29.3	64.1	17.8	8.2	6.2	27.2	1.5	0.5	0.7	155.5
NCMPAIMP	67.9	31.7	51.3	25.6	46.3	10.8	36.3	40.8	27.9	338.7
SOUTHEAST	216.3	238.1	718.8	394.6	610.7	473.8	314.5	433.1	417.9	3,817.8
SOUTHWEST	161.0	156.2	164.8	384.5	193.9	201.0	301.4	218.2	85.9	1,866.9
SOUTHIMP	166.5	343.6	686.3	313.1	390.0	430.8	235.6	135.4	105.0	2,806.3
SOUTHEXP	(1,236.4)	(1,412.9)	(1,745.9)	(1,249.8)	(1,961.4)	(1,580.0)	(1,515.6)	(1,622.4)	(718.1)	(13,042.4)
CPLEEXP	(28.4)	(14.5)	(13.1)	(22.0)	(24.0)	(23.5)	(21.9)	(12.1)	(24.6)	(184.1)
DUKEXP	0.0	0.0	0.0	(8.8)	(0.9)	(16.0)	0.0	(24.6)	(0.5)	(50.9)
NCMPAEXP	(1.7)	(0.9)	(0.8)	(1.4)	(1.3)	(0.4)	(0.4)	(170.2)	(0.3)	(177.5)
SOUTHEAST	(59.9)	(83.4)	(26.0)	(151.0)	(232.1)	(110.3)	(89.4)	(123.3)	(48.2)	(923.5)
SOUTHWEST	(507.8)	(648.2)	(831.2)	(611.3)	(662.4)	(571.3)	(613.5)	(687.9)	(357.2)	(5,490.8)
SOUTHEXP	(638.6)	(665.8)	(874.8)	(455.2)	(1,040.7)	(858.5)	(790.4)	(604.3)	(287.2)	(6,215.6)
Total	(1,433.0)	(1,746.3)	(1,802.8)	(1,992.1)	(1,875.3)	(332.9)	(863.2)	(1,073.0)	(1,023.8)	(12,142.4)

23 In the Day-Ahead Energy Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

Table 9-11 Up-to congestion scheduled net interchange volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	26.1	123.2	145.2	107.5	175.5	179.5	286.0	336.6	11.4	1,391.2
IMO	218.6	259.9	255.7	64.0	(65.1)	24.7	92.7	117.4	56.1	1,023.7
LINDENVFT	(61.7)	(47.1)	15.3	(65.7)	(37.1)	(59.9)	62.8	15.4	7.9	(170.0)
MISO	(195.6)	5.7	243.1	296.4	170.4	665.0	501.9	385.0	145.1	2,217.0
NEPTUNE	(73.5)	41.0	(3.1)	8.5	(92.9)	(44.5)	4.9	40.2	1.5	(118.0)
NIPSCO	(763.3)	(19.3)	(274.5)	(630.7)	(616.1)	(33.9)	(242.9)	(172.1)	(113.9)	(2,866.7)
NORTHWEST	457.7	510.3	402.6	371.4	128.0	(116.6)	47.6	(100.6)	103.7	1,804.0
NYIS	49.3	128.0	42.5	65.6	163.3	252.7	355.4	149.7	86.8	1,293.2
OVEC	498.4	(674.3)	(130.4)	(298.6)	(223.8)	342.4	9.4	(416.7)	28.0	(865.6)
SOUTHIMP	445.3	587.1	1,178.8	853.1	926.5	913.4	751.2	751.2	546.3	6,952.9
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	216.3	238.1	718.8	346.0	610.6	473.8	314.5	433.1	417.9	3,769.2
SOUTHWEST	161.0	156.2	164.8	384.5	193.9	201.0	301.4	218.2	79.9	1,861.0
SOUTHIMP	68.0	192.9	295.2	122.5	121.9	238.6	135.3	99.8	48.5	1,322.7
SOUTHEXP	(1,179.8)	(1,397.4)	(1,732.0)	(1,217.5)	(1,928.3)	(1,524.3)	(1,445.9)	(1,366.5)	(605.3)	(12,397.1)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(59.9)	(83.4)	(26.0)	(151.0)	(232.1)	(110.3)	(86.8)	(123.3)	(31.5)	(904.2)
SOUTHWEST	(507.8)	(648.2)	(831.2)	(611.3)	(662.4)	(571.3)	(613.5)	(687.9)	(346.1)	(5,479.7)
SOUTHEXP	(612.2)	(665.8)	(874.8)	(455.2)	(1,033.8)	(842.7)	(745.6)	(555.3)	(227.7)	(6,013.2)
Total Interfaces	(578.5)	(482.9)	143.1	(446.1)	(1,399.6)	598.5	423.1	(260.6)	267.6	(1,735.4)
INTERNAL	35,413.4	36,715.9	41,839.2	46,018.1	47,071.4	42,767.0	42,702.3	42,796.1	15,430.5	350,754.0
Total	34,834.9	36,109.8	41,837.1	45,464.5	45,496.3	43,186.0	42,839.5	42,198.9	15,686.6	347,627.3

Table 9-12 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	187.4	317.0	257.6	162.1	221.6	246.9	365.8	409.1	82.2	2,249.6
IMO	358.4	375.9	340.3	298.4	336.3	312.4	386.3	383.4	238.1	3,029.6
LINDENVFT	84.4	70.4	100.5	59.2	56.8	74.9	144.8	85.4	36.6	713.0
MISO	334.1	318.3	445.6	544.0	397.3	734.7	620.7	462.1	247.9	4,104.6
NEPTUNE	38.4	133.4	156.1	78.9	36.7	26.0	93.5	81.9	17.3	662.2
NIPSCO	85.5	172.9	80.0	72.6	69.0	114.6	69.2	86.1	32.0	781.9
NORTHWEST	614.8	605.4	503.2	505.7	270.2	168.8	252.1	165.8	184.5	3,270.5
NYIS	810.5	787.0	726.5	806.2	902.4	1,058.5	1,146.4	925.9	778.8	7,942.1
OVEC	1,646.5	1,138.6	1,350.5	1,180.3	1,468.7	1,846.8	1,573.3	1,421.9	988.2	12,614.7
SOUTHIMP	641.1	834.2	1,639.1	1,129.2	1,247.2	1,184.5	889.3	828.0	637.3	9,029.9
CPLEIMP	0.0	0.6	0.0	3.2	0.0	40.9	0.0	0.0	0.0	44.7
DUKIMP	29.3	64.1	17.8	8.2	6.2	27.2	1.5	0.5	0.7	155.5
NCMPAIMP	67.9	31.7	51.3	25.6	46.3	10.8	36.3	40.8	27.9	338.7
SOUTHEAST	216.3	238.1	718.8	394.6	610.7	473.8	314.5	433.1	417.9	3,817.8
SOUTHWEST	161.0	156.2	164.8	384.5	193.9	201.0	301.4	218.2	85.9	1,866.9
SOUTHIMP	166.5	343.6	686.3	313.1	390.0	430.8	235.6	135.4	105.0	2,806.3
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,801.1	4,752.9	5,599.2	4,836.7	5,006.1	5,768.0	5,541.5	4,849.6	3,242.8	44,398.0

Table 9-13 Up-to congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	187.4	317.0	257.6	162.1	221.6	246.9	365.8	409.1	82.2	2,249.6
IMO	257.5	337.5	324.4	193.0	202.6	188.5	282.1	195.6	73.0	2,054.2
LINDENVFT	80.8	67.8	97.0	58.1	45.8	59.2	136.4	80.3	25.2	650.7
MISO	291.2	318.3	445.3	541.7	392.5	732.3	620.7	458.0	195.5	3,995.4
NEPTUNE	38.4	133.4	156.1	78.9	36.7	26.0	93.5	81.9	17.3	662.2
NIPSCO	85.5	172.9	80.0	72.6	69.0	114.6	69.2	86.1	27.3	777.2
NORTHWEST	614.8	605.4	503.2	505.7	270.2	168.8	252.1	165.8	176.6	3,262.6
NYIS	134.6	177.6	115.2	178.0	231.4	303.3	393.7	177.5	117.1	1,828.5
OVEC	919.3	410.3	621.0	741.4	1,001.4	1,195.5	913.1	789.4	342.9	6,934.4
SOUTHIMP	445.3	587.1	1,178.8	853.1	926.5	913.4	751.2	751.2	546.3	6,952.9
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	216.3	238.1	718.8	346.0	610.6	473.8	314.5	433.1	417.9	3,769.2
SOUTHWEST	161.0	156.2	164.8	384.5	193.9	201.0	301.4	218.2	79.9	1,861.0
SOUTHIMP	68.0	192.9	295.2	122.5	121.9	238.6	135.3	99.8	48.5	1,322.7
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3,054.9	3,127.2	3,778.6	3,384.6	3,397.8	3,948.4	3,877.9	3,194.9	1,603.4	29,367.6

Table 9-14 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	206.9	325.6	189.5	54.7	46.6	68.1	80.8	72.5	90.7	1,135.5
IMO	39.0	79.2	69.2	129.0	267.8	163.8	189.4	78.2	44.2	1,059.9
LINDENVFT	156.4	139.8	101.1	136.7	88.5	129.3	86.1	71.5	28.1	937.3
MISO	776.9	966.5	1,422.6	1,367.7	782.2	792.3	777.8	411.8	1,011.4	8,309.1
NEPTUNE	392.2	530.0	589.5	516.2	390.0	448.7	523.1	509.2	335.4	4,234.4
NIPSCO	848.8	192.2	354.4	703.3	685.1	148.5	312.1	258.3	151.2	3,653.9
NORTHWEST	590.7	470.6	539.1	364.9	647.1	873.2	813.1	702.4	666.9	5,668.0
NYIS	1,565.8	1,297.8	1,639.2	1,266.7	771.4	1,027.2	1,185.6	974.6	860.9	10,589.1
OVEC	421.0	1,084.6	751.4	1,040.0	1,241.5	870.1	921.1	1,221.7	359.5	7,910.8
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,236.4	1,412.9	1,745.9	1,249.8	1,961.4	1,580.0	1,515.6	1,622.4	718.1	13,042.4
CPLEEXP	28.4	14.5	13.1	22.0	24.0	23.5	21.9	12.1	24.6	184.1
DUKEXP	0.0	0.0	0.0	8.8	0.9	16.0	0.0	24.6	0.5	50.9
NCMPAEXP	1.7	0.9	0.8	1.4	1.3	0.4	0.4	170.2	0.3	177.5
SOUTHEAST	59.9	83.4	26.0	151.0	232.1	110.3	89.4	123.3	48.2	923.5
SOUTHWEST	507.8	648.2	831.2	611.3	662.4	571.3	613.5	687.9	357.2	5,490.8
SOUTHEXP	638.6	665.8	874.8	455.2	1,040.7	858.5	790.4	604.3	287.2	6,215.6
Total	6,234.0	6,499.3	7,402.0	6,828.8	6,881.5	6,101.0	6,404.7	5,922.6	4,266.6	56,540.4

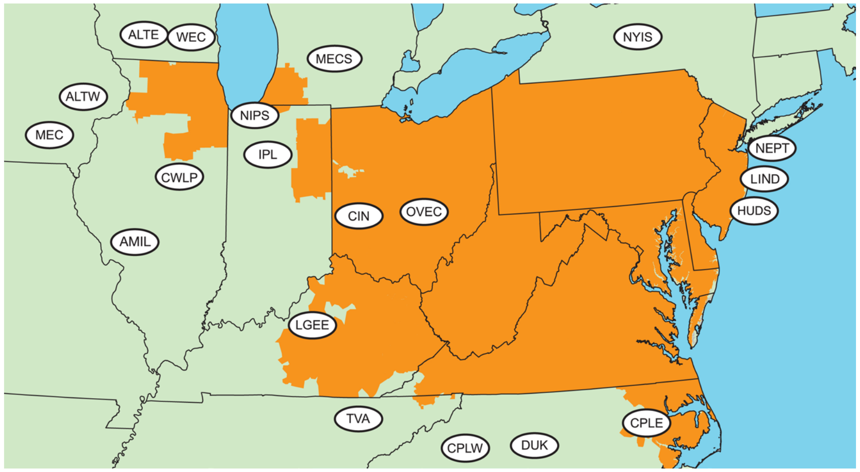
Table 9-15 Up-to congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	161.2	193.7	112.4	54.7	46.0	67.3	79.8	72.5	70.7	858.4
IMO	39.0	77.6	68.7	129.0	267.8	163.8	189.4	78.2	17.0	1,030.4
LINDENVFT	142.6	114.9	81.7	123.8	82.9	119.1	73.6	64.9	17.3	820.8
MISO	486.8	312.6	202.2	245.2	222.1	67.3	118.7	73.0	50.4	1,778.4
NEPTUNE	111.9	92.4	159.3	70.4	129.7	70.4	88.6	41.7	15.7	780.1
NIPSCO	848.8	192.2	354.4	703.3	685.1	148.5	312.1	258.3	141.2	3,644.0
NORTHWEST	157.1	95.1	100.6	134.4	142.2	285.4	204.5	266.4	72.9	1,458.6
NYIS	85.3	49.6	72.8	112.4	68.2	50.6	38.3	27.8	30.4	535.3
OVEC	420.9	1,084.6	751.4	1,040.0	1,225.2	853.1	903.7	1,206.1	314.9	7,800.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,179.8	1,397.4	1,732.0	1,217.5	1,928.3	1,524.3	1,445.9	1,366.5	605.3	12,397.1
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	59.9	83.4	26.0	151.0	232.1	110.3	86.8	123.3	31.5	904.2
SOUTHWEST	507.8	648.2	831.2	611.3	662.4	571.3	613.5	687.9	346.1	5,479.7
SOUTHEXP	612.2	665.8	874.8	455.2	1,033.8	842.7	745.6	555.3	227.7	6,013.2
Total	3,633.4	3,610.2	3,635.5	3,830.6	4,797.4	3,349.9	3,454.7	3,455.5	1,335.8	31,103.0

Table 9-16 Active interfaces: January through September, 2014[24]

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

Figure 9-3 PJM's footprint and its external interfaces



24 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of June 30, 2014, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.

Table 9-17 Active pricing points: January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power 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 the difference between actual and scheduled power flows at specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[25]

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market based price differentials that result from the actual physical flows on the transmission system.

25 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both PJM's border with MISO (higher scheduled than actual flows) and PJM's southern border (higher actual than scheduled flows). In the first nine months of 2014, there were net scheduled flows of 7,349 GWh through MISO that received an interface pricing point associated with the southern border. Conversely, in the first nine months of 2014, there were no net scheduled flows across the southern border that received the MISO interface pricing point.

In the first nine months of 2014, net scheduled interchange was -1,081 GWh and net actual interchange was -331 GWh, a difference of 750 GWh. In the first nine months of 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh.[26] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated

26 The "Net Scheduled" values shown in Table 9-18 include dynamic schedules. Dynamic schedules are commonly used for scheduling generation from one another balancing authority area to another. As defined by NERC, a dynamic schedule is a telemetered reading or value from such a generating unit that is updated in real time and used as a schedule in the AGC/ACE equation of the BA to which it is scheduled. The hourly integrated values of dynamic schedules are treated as a schedule for interchange accounting purposes. Table 9-1 through Table 9-6 represent block scheduled transactions, submitted through the Enhanced Energy Scheduling (EES) application and tagged through the NERC e-tag process only. As a result, the net interchange in Table 9-18 does not match the interchange values shown in Table 9-1 through Table 9-6.

inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[27]

Table 9-18 Net scheduled and actual PJM flows by interface (GWh): January through September, 2014

	Actual	Net Scheduled	Difference (GWh)
CPLE	5,429	(114)	5,543
CPLW	(1,350)	6	(1,356)
DUK	(340)	1,195	(1,536)
LGEE	2,426	1,637	789
MEC	(1,851)	(4,455)	2,604
MISO	(11,740)	(1,223)	(10,517)
ALTE	(5,641)	(3,434)	(2,207)
ALTW	(1,577)	(404)	(1,173)
AMIL	7,674	5,476	2,198
CIN	(4,019)	(867)	(3,152)
CWLP	(529)	0	(529)
IPL	850	(415)	1,265
MECS	(8,739)	(981)	(7,758)
NIPS	(3,657)	660	(4,317)
WEC	3,898	(1,258)	5,156
NYISO	(7,002)	(7,222)	220
HUDS	(444)	(444)	0
LIND	(333)	(333)	0
NEPT	(3,379)	(3,379)	0
NYIS	(2,845)	(3,066)	220
OVEC	10,104	7,730	2,374
TVA	3,993	1,364	2,629
Total	(331)	(1,081)	750

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the flows that will receive the specific interface price.[28] The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

27 See PJM. "Manual 12: Balancing Operations," Revision 30 (December 1, 2013).

28 The terms balancing authority and control area are used interchangeably in this section. The NERC tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model," <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf>. (August 2008.)

The differences between the scheduled and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. Scheduled transactions are assigned interface pricing points based on the generation balancing authority and load balancing authority. Scheduled power flows are assigned to interfaces based on the OASIS path that reflects the path of energy into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-19 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP interface pricing points were created as part of operating agreements with external balancing authorities, and do not reflect physical ties different from the SouthIMP and SouthEXP interface pricing points.

Because the SouthIMP and SouthEXP interface pricing points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP interface pricing point. Conversely, if there are net actual imports into the PJM footprint from the southern region, there cannot be net actual exports to the southern region and therefore there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points with the southern region, comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points, provides some insight into how effective the interface pricing point mappings are. To accurately calculate the loop flows at the southern region, the net actual flows from the southern region (10,158 GWh of imports at the SouthIMP interface pricing point) are compared with the net scheduled flows at the aggregate southern region (the sum of the net scheduled flows at the SouthIMP and SouthEXP interface pricing points, or 11,666 GWh).

The IMO interface pricing point with the IESO was created to reflect the fact that transactions that originate or sink in the IMO balancing authority create flows that are split between the MISO and NYISO interface pricing points, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Actual flows associated with the IMO interface pricing point are shown as zero because there is no PJM/IMO interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 9-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through September, 2014

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(444)	(444)	0
IMO	0	3,505	(3,505)
LINDENVFT	(333)	(333)	0
MISO	(11,740)	(16,529)	4,789
NEPTUNE	(3,379)	(3,379)	0
NORTHWEST	(1,851)	(700)	(1,150)
NYIS	(2,845)	(2,596)	(249)
OVEC	10,104	7,730	2,374
SOUTHIMP	10,158	13,573	(3,415)
CPLEIMP	0	76	(76)
DUKIMP	0	641	(641)
NCMPAIMP	0	541	(541)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	10,158	12,315	(2,156)
SOUTHEXP	0	(1,906)	1,906
CPLEEXP	0	(216)	216
DUKEXP	0	(643)	643
NCMPAEXP	0	0	0
SOUTHEAST	0	(3)	3
SOUTHWEST	0	(9)	9
SOUTHEXP	0	(1,035)	1,035
Total	(331)	(1,081)	750

Table 9-20 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the Ontario Independent Electricity System Operator (IMO) entered the PJM Energy Market.

Table 9-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through September, 2014

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(444)	(444)	0
LINDENVFT	(333)	(333)	0
MISO	(11,740)	(12,932)	1,192
NEPTUNE	(3,379)	(3,379)	0
NORTHWEST	(1,851)	(700)	(1,150)
NYIS	(2,845)	(2,689)	(157)
OVEC	10,104	7,730	2,374
SOUTHIMP	10,158	13,573	(3,415)
CPLEIMP	0	76	(76)
DUKIMP	0	641	(641)
NCMPAIMP	0	541	(541)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	10,158	12,315	(2,156)
SOUTHEXP	0	(1,906)	1,906
CPLEEXP	0	(216)	216
DUKEXP	0	(643)	643
NCMPAEXP	0	0	0
SOUTHEAST	0	(3)	3
SOUTHWEST	0	(9)	9
SOUTHEXP	0	(1,035)	1,035
Total	(331)	(1,081)	750

PJM ensures that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC eTag. Assigning prices in this manner is an adequate method for ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this methodology does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loops flows would be reduced.

The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.

Table 9-21 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the interface pricing points that were assigned to energy transactions that had market paths at each of PJM's interfaces. For example, Table 9-21 shows that in the first nine months of 2014, the majority of imports to the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the IMO interface, and thus actual flows were assigned the IMO interface pricing point (874 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM Energy Market at the MISO Interface, and thus were assigned the MISO interface pricing point (2,914 GWh).

Table 9-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through September, 2014

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(5,641)	(3,434)	(2,207)	IPL		850	(415)	1,265
	MISO	(5,641)	(3,521)	(2,120)		IMO	0	901	(901)
	SOUTHIMP	0	87	(87)		MISO	850	(1,407)	2,258
ALTW		(1,577)	(404)	(1,173)		NORTHWEST	0	(1)	1
	MISO	(1,577)	(404)	(1,173)		SOUTHEXP	0	(1)	1
AMIL		7,674	5,476	2,198		SOUTHIMP	0	92	(92)
	MISO	7,674	31	7,643	LGEE		2,426	1,637	789
	SOUTHIMP	0	5,454	(5,454)		SOUTHEXP	0	(31)	31
	SOUTHWEST	0	(9)	9		SOUTHIMP	2,426	1,668	758
CIN		(4,019)	(867)	(3,152)	LIND		(333)	(333)	0
	IMO	0	874	(874)		LINDENVFT	(333)	(333)	0
	MISO	(4,019)	(2,914)	(1,105)	MEC		(1,851)	(4,455)	2,604
	NORTHWEST	0	(9)	9		IMO	0	2	(2)
	NYIS	0	377	(377)		MISO	0	(3,994)	3,994
	SOUTHEXP	0	(2)	2		NORTHWEST	(1,851)	(690)	(1,161)
	SOUTHIMP	0	807	(807)		SOUTHIMP	0	228	(228)
CPLE		5,429	(114)	5,543	MECS		(8,739)	(981)	(7,758)
	CPLEEXP	0	(216)	216		IMO	0	1,821	(1,821)
	CPLEIMP	0	76	(76)		MISO	(8,739)	(3,049)	(5,690)
	DUKEXP	0	(7)	7		NORTHWEST	0	(1)	1
	DUKIMP	0	7	(7)		SOUTHEXP	0	(15)	15
	SOUTHEXP	0	(16)	16		SOUTHIMP	0	263	(263)
	SOUTHIMP	5,429	46	5,384	NEPT		(3,379)	(3,379)	0
	SOUTHEAST	0	(3)	3		NEPTUNE	(3,379)	(3,379)	0
CPLW		(1,350)	6	(1,356)	NIPS		(3,657)	660	(4,317)
	SOUTHIMP	(1,350)	6	(1,356)		MISO	(3,657)	(11)	(3,645)
CWLP		(529)	0	(529)		SOUTHIMP	0	672	(672)
	MISO	(529)	0	(529)	NYIS		(2,845)	(3,066)	220
DUK		(340)	1,195	(1,536)		IMO	0	(92)	92
	DUKEXP	0	(636)	636		NYIS	(2,845)	(2,973)	128
	DUKIMP	0	634	(634)	OVEC		10,104	7,730	2,374
	NCMPAIMP	0	541	(541)		OVEC	10,104	7,730	2,374
	SOUTHEXP	0	(695)	695	TVA		3,993	1,364	2,629
	SOUTHIMP	(340)	1,351	(1,691)		SOUTHEXP	0	(274)	274
HUDS		(444)	(444)	0		SOUTHIMP	3,993	1,638	2,355
	HUDSONTP	(444)	(444)	0	WEC		3,898	(1,258)	5,156
						MISO	3,898	(1,259)	5,158
						SOUTHEXP	0	(1)	1
						SOUTHIMP	0	2	(2)
					Grand Total		(331)	(1,081)	750

Table 9-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through September, 2014

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(216)	216	NORTHWEST		(1,851)	(700)	(1,150)
	CPLE	0	(216)	216		CIN	0	(9)	9
CPLEIMP		0	76	(76)		IPL	0	(1)	1
	CPLE	0	76	(76)		MEC	(1,851)	(690)	(1,161)
DUKEXP		0	(643)	643		MECS	0	(1)	1
	CPLE	0	(7)	7	NYIS		(2,845)	(2,596)	(249)
	DUK	0	(636)	636		CIN	0	377	(377)
DUKIMP		0	641	(641)		NYIS	(2,845)	(2,973)	128
	CPLE	0	7	(7)	OVEC		10,104	7,730	2,374
	DUK	0	634	(634)		OVEC	10,104	7,730	2,374
HUDSONTP		(444)	(444)	0	SOUTHEAST		0	(3)	3
	HUDS	(444)	(444)	0		CPLE	0	(3)	3
IMO		0	3,505	(3,505)	SOUTHEXP		0	(1,035)	1,035
	CIN	0	874	(874)		CIN	0	(2)	2
	IPL	0	901	(901)		CPLE	0	(16)	16
	MEC	0	2	(2)		DUK	0	(695)	695
	MECS	0	1,821	(1,821)		IPL	0	(1)	1
	NYIS	0	(92)	92		LGEE	0	(31)	31
LINDENVFT		(333)	(333)	0		MECS	0	(15)	15
	LIND	(333)	(333)	0		TVA	0	(274)	274
MISO		(11,740)	(16,529)	4,789		WEC	0	(1)	1
	ALTE	(5,641)	(3,521)	(2,120)	SOUTHIMP		10,158	12,315	(2,156)
	ALTW	(1,577)	(404)	(1,173)		ALTE	0	87	(87)
	AMIL	7,674	31	7,643		AMIL	0	5,454	(5,454)
	CIN	(4,019)	(2,914)	(1,105)		CIN	0	807	(807)
	CWLP	(529)	0	(529)		CPLE	5,429	46	5,384
	IPL	850	(1,407)	2,258		CPLW	(1,350)	6	(1,356)
	MEC	0	(3,994)	3,994		DUK	(340)	1,351	(1,691)
	MECS	(8,739)	(3,049)	(5,690)		IPL	0	92	(92)
	NIPS	(3,657)	(11)	(3,645)		LGEE	2,426	1,668	758
	WEC	3,898	(1,259)	5,158		MEC	0	228	(228)
NCMPAIMP		0	541	(541)		MECS	0	263	(263)
	DUK	0	541	(541)		NIPS	0	672	(672)
NEPTUNE		(3,379)	(3,379)	0		TVA	3,993	1,638	2,355
	NEPT	(3,379)	(3,379)	0		WEC	0	2	(2)
					SOUTHWEST		0	(9)	9
						AMIL	0	(9)	9
					Grand Total		(331)	(1,081)	750

Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point and interface. This table shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-22 shows that in the first nine months of 2014, the majority of imports to the PJM Energy Market for which a market participant specified a generation control area for which it was assigned the IMO interface pricing point, had market paths that entered the PJM Energy Market at the MECS Interface (1,821 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified a load control area for which it was assigned the IMO interface pricing point, had market paths that exited the PJM Energy Market at the NYIS Interface (92 GWh).

PJM and MISO Interface Prices

If interface prices were defined in a comparable manner by PJM and MISO, and if time lags were not built into the rules governing interchange transactions then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that these conditions do not exist is important in explaining the observed relationship between interface prices and inter-RTO power flows, and those price differentials.

Both the PJM/MISO and MISO/PJM interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM Interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows. PJM used the LMP at nine buses within MISO to calculate the PJM/MISO Interface price, prior to the change on June 1, 2014, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[29,30] When a M2M constraint binds, PJM's LMP calculations at the nine selected buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. PJM's MISO interface pricing point is a weighted average price of the selected bus LMPs.

In 2013, questions were raised in the PJM/MISO Joint and Common Market (JCM) Initiative meetings whether the existing interface definitions utilized by PJM and MISO were accurately reflecting the value of congestion applied to interchange transactions when a M2M constraint is binding in either footprint.

PJM modified the definition of the PJM/MISO Interface effective June 1, 2014. The new interface definition includes ten equally weighted buses that are close to the PJM/MISO border. The ten buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie line flows between PJM and MISO occurred on ten ties composed of MISO and PJM monitored facilities. PJM selected generator buses electrically close to those ten tie lines. A PJM generator bus was selected for MISO monitored tie lines, and a MISO generator bus was selected for PJM monitored tie lines.

Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first nine months of 2014, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first nine months of 2014, the PJM average hourly real-time LMP at the PJM/MISO border was $39.37 while the MISO real-time LMP at the border was $39.40, a difference of $0.03. While the average hourly LMP difference at the PJM/MISO border was $0.03, the average of the absolute values of the hourly differences was $14.21. The average hourly flow in the first nine months of 2014 was -1,792 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.) The direction of flow was consistent with price differentials in 53.0 percent of the hours in the first nine months of 2014. When the MISO/PJM interface price was greater than the PJM/MISO interface price, the average difference was $13.56. When the PJM/MISO interface price was greater than the MISO/PJM interface price, the average difference was $14.94. In the first nine months of 2014, 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 $12.35. 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 $23.99. 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 $44.27. 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 $10.69.

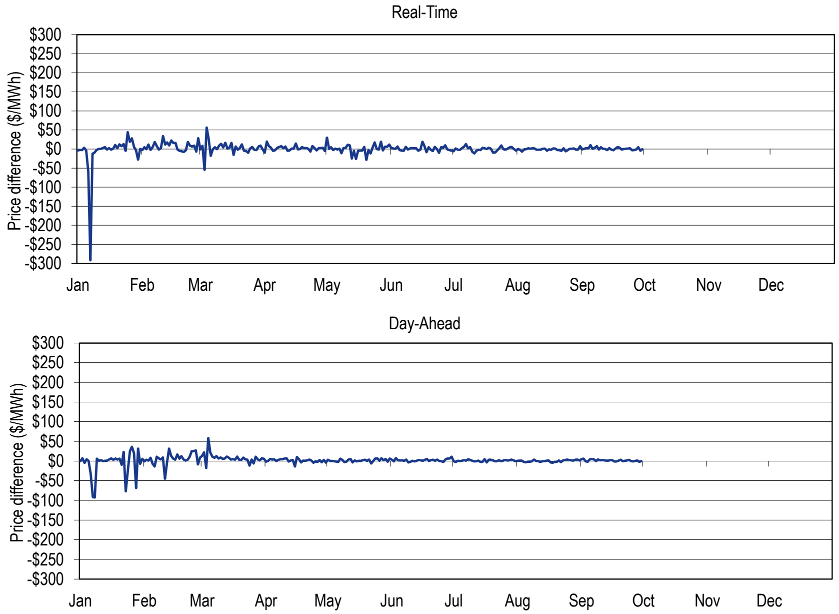
In the first nine months of 2014, the day-ahead PJM average hourly LMP at the PJM/MISO border was $41.16 while the MISO LMP at the border was $42.45, a difference of $1.29 per MWh.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-4). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 9-6).

29 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 15, 2014). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

30 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (Accessed October 15, 2014).

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through September, 2014



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In the first nine months of 2014, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 3,474 hours (53.0 percent of all hours), and was inconsistent with price differentials in 3,077 hours (47.0 percent of all hours). Table 9-23 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 3,077 hours where flows were in a direction inconsistent with price differences, 2,618 of those hours (85.1 percent) had a price difference greater than or equal to $1.00 and 1,410 of those hours (45.8 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $592.36. Of the 3,474 hours where flows were consistent with price differences, 3,036 of those hours (87.4 percent) had a price difference greater than or equal to $1.00 and 1,720 of all such hours (49.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,576.11.

Table 9-23 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through September, 2014

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	3,077	100.0%	3,474	100.0%
$1.00	2,618	85.1%	3,036	87.4%
$5.00	1,410	45.8%	1,720	49.5%
$10.00	846	27.5%	1,105	31.8%
$15.00	598	19.4%	798	23.0%
$20.00	445	14.5%	633	18.2%
$25.00	347	11.3%	487	14.0%
$50.00	141	4.6%	209	6.0%
$75.00	70	2.3%	113	3.3%
$100.00	40	1.3%	61	1.8%
$200.00	15	0.5%	20	0.6%
$300.00	4	0.1%	15	0.4%
$400.00	3	0.1%	8	0.2%
$500.00	2	0.1%	8	0.2%

Distribution and Prices of Hourly Flows at the PJM/MISO Interface After June 1, 2014, Interface Pricing Point Modification

PJM modified the definition of the PJM/MISO Interface effective June 1, 2014. The new interface definition includes ten equally weighted buses that are close to the PJM/MISO border. In the first four months of operations under the new interface pricing definition, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 1,606 of the 2,927 hours (54.9 percent of all hours), and was inconsistent with price differentials in 1,321 of the 2,927 hours (45.1 percent of all hours). Table 9-24 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices between June 1, 2014 and September 30, 2014. Of the 1,321 hours where flows were in a direction inconsistent with price differences, 1,021 of those hours (77.3 percent) had a price difference greater than or equal to $1.00 and 434 of those hours (32.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $173.18. Of the 1,606 hours where flows were consistent with price differences, 1,329 of those hours (82.8 percent) had a price difference greater than or equal to $1.00 and 534 of all such hours (33.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $195.80.

Table 9-24 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: June 1, 2014 through September 30, 2014

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	1,321	100.0%	1,606	100.0%
$1.00	1,021	77.3%	1,329	82.8%
$5.00	434	32.9%	534	33.3%
$10.00	243	18.4%	287	17.9%
$15.00	158	12.0%	178	11.1%
$20.00	117	8.9%	129	8.0%
$25.00	87	6.6%	79	4.9%
$50.00	28	2.1%	27	1.7%
$75.00	8	0.6%	8	0.5%
$100.00	3	0.2%	6	0.4%
$200.00	0	0.0%	0	0.0%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[31]

Real-Time and Day-Ahead PJM/NYISO Interface Prices

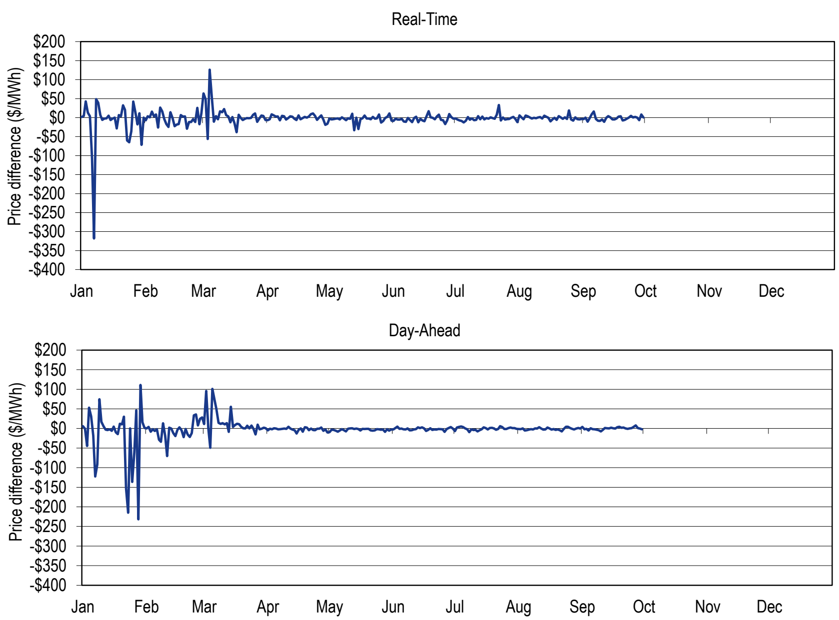
In the first nine months of 2014, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In the first nine months of 2014, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In the first nine months of 2014, the PJM average hourly LMP at the PJM/NYISO border was $57.36 while the NYISO LMP at the border was $55.13, a difference of $2.22. While the average hourly LMP difference at the PJM/NYISO border was $2.22, the average of the absolute value of the hourly difference was $21.73. The average hourly flow in the first nine months of 2014 was -434 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.) The direction of flow was consistent with price differentials in 56.0 percent of the hours in the first nine months of 2014. In the first nine months of 2014, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS interface price, the average difference was $20.53. When the PJM/NYIS interface price was greater than the NYIS/PJM proxy bus price, the average difference was $22.84. In the first nine months of 2014, 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 $21.00. 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 $18.78. 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 $24.55. 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 $21.90.

31 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

In the first nine months of 2014, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $61.18 while the NYIS LMP at the border was $58.81, a difference of $2.37.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-5). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 9-6).

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through September, 2014



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first nine months of 2014, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,667 (56.0 percent of all hours), and was inconsistent with price differences in 2,884 hours (44.0 percent of all hours). Table 9-25 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 2,884 hours where flows where flows were in a direction inconsistent with price differences, 2,574 of those hours (89.3 percent) had a price difference greater than or equal to $1.00 and 1,719 of all those hours (59.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $577.83. Of the 3,667 hours where flows were consistent with price differences, 3,379 of those hours (92.1 percent) had a price difference greater than or equal to $1.00 and 2,308 of all such hours (62.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,311.87.

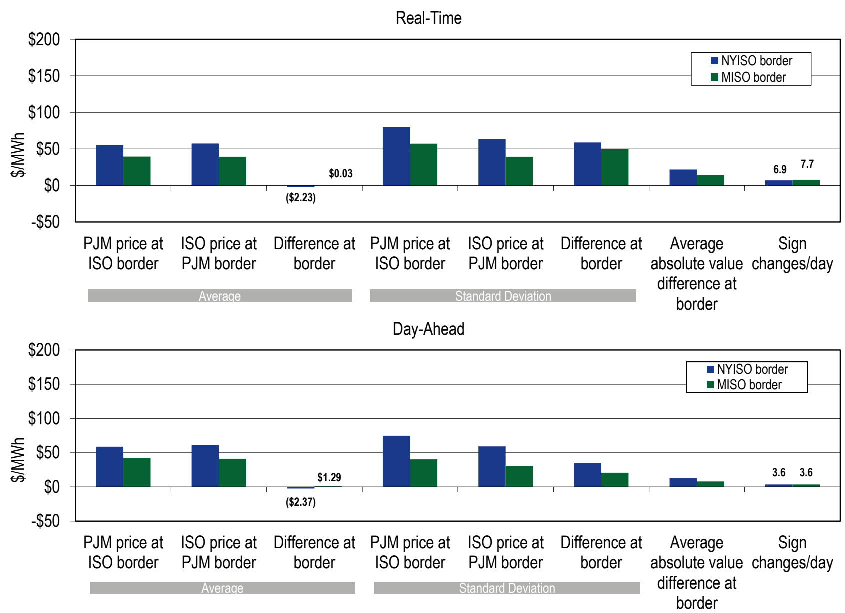
Table 9-25 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through September, 2014

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	2,884	100.0%	3,667	100.0%
$1.00	2,574	89.3%	3,379	92.1%
$5.00	1,719	59.6%	2,308	62.9%
$10.00	1,134	39.3%	1,488	40.6%
$15.00	849	29.4%	1,073	29.3%
$20.00	662	23.0%	845	23.0%
$25.00	560	19.4%	704	19.2%
$50.00	290	10.1%	366	10.0%
$75.00	184	6.4%	233	6.4%
$100.00	121	4.2%	144	3.9%
$200.00	42	1.5%	48	1.3%
$300.00	17	0.6%	20	0.5%
$400.00	7	0.2%	10	0.3%
$500.00	2	0.1%	8	0.2%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Figure 9-6, including average prices and measures of variability.

Figure 9-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through September, 2014



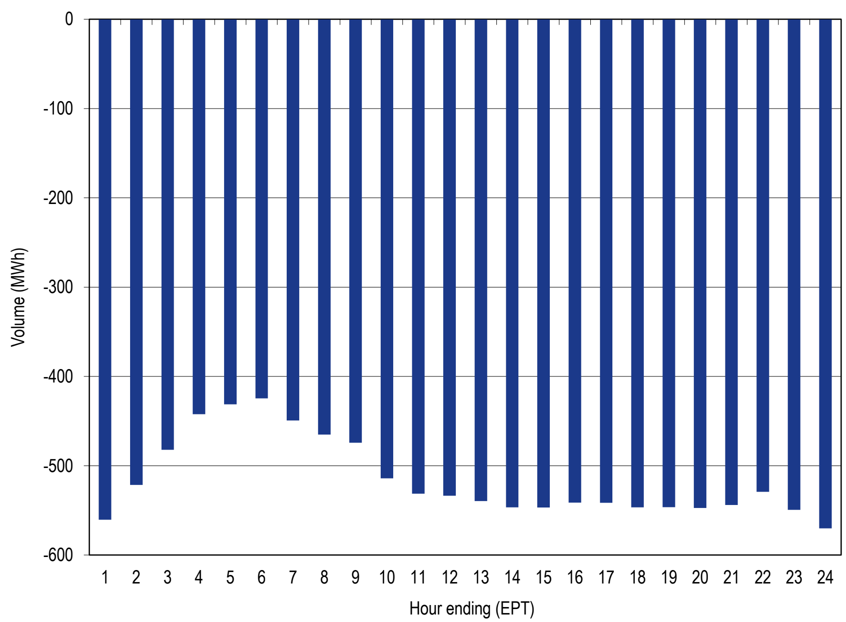
Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus. In the first nine months of 2014, the PJM average hourly LMP at the Neptune Interface was $58.43 while the NYISO LMP at the Neptune Bus was $68.62, a difference of $10.18.[32] While the average hourly LMP difference at the PJM/Neptune border was $10.18, the average of the absolute value of the hourly difference was $32.62. The average hourly flow during the first nine months of 2014 was -516 MW.[33] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 58.9 percent of the hours in the first nine months of 2014. When the NYISO/Neptune bus price was greater than the PJM/NEPT interface price, the average hourly price difference was $35.98. When the PJM/NEPT interface price was greater than the NYISO/Neptune bus price, the average price difference was $27.72.

32 In the first nine months of 2014, there were 590 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $58.04 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.75, a difference of $8.71.

33 The average hourly flow in the first nine months of 2014, ignoring hours with no flow, on the Neptune DC Tie line was -567 MW.

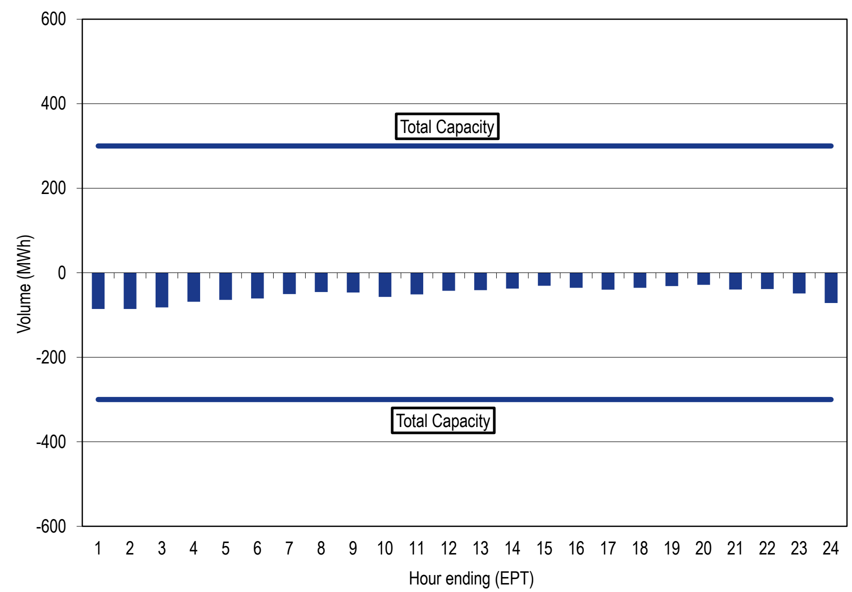
Figure 9-7 Neptune hourly average flow: January through September, 2014



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). In the first nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus. In the first nine months of 2014, the PJM average hourly LMP at the Linden Interface was $59.39 while the NYISO LMP at the Linden Bus was $60.42, a difference of $1.04.[34] While the average hourly LMP difference at the PJM/Linden border was $1.04, the average of the absolute value of the hourly difference was $26.20. The average hourly flow in the first nine months of 2014 was -51 MW.[35] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 56.2 percent of the hours in the first nine months of 2014. When the NYISO/Linden bus price was greater than the PJM/LIND interface price, the average hourly price difference was $24.64. When the PJM/LIND interface price was greater than the NYISO/Linden bus price, the average price difference was $28.12.

Figure 9-8 Linden hourly average flow: January through September, 2014[36]



Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO

34 In the first nine months of 2014, there were 1,510 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $63.82 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.24, a difference of $2.42.

35 The average hourly flow in the first nine months of 2014, ignoring hours with no flow, on the Linden VFT line was -66 MW.

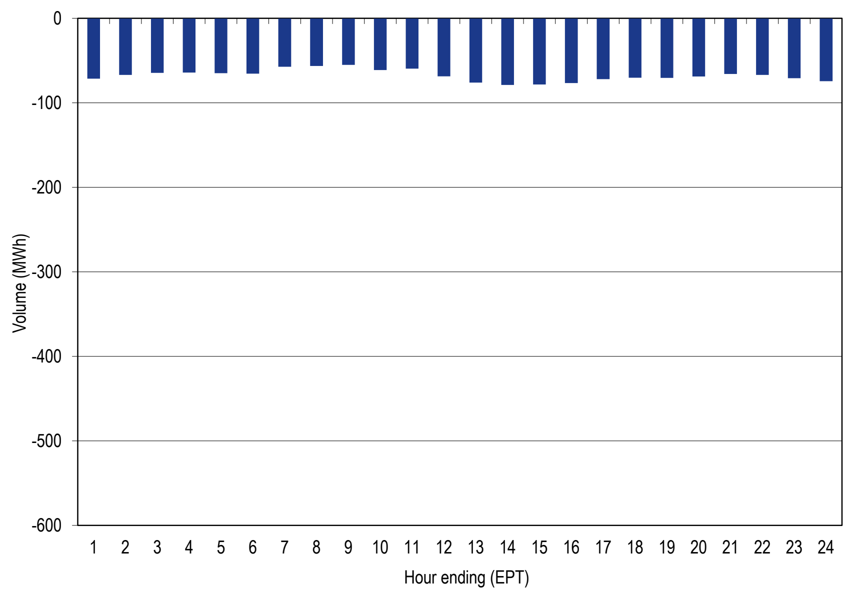
36 The Linden VFT line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie line.

(Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights). In the first nine months of 2014, the average hourly flow (PJM to NYISO) was inconsistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus. The PJM average hourly LMP at the Hudson Interface was $67.19 while the NYISO LMP at the Hudson Bus was $64.77, a difference of $2.42.[37] While the average hourly LMP difference at the PJM/Hudson border was $2.42, the average of the absolute value of the hourly difference was $29.70. The average hourly flow during the first nine months of 2014 was -68 MW.[38] (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.) The flows were consistent with price differentials in 59.3 percent of the hours in the first nine months of 2014. When the NYISO/Hudson bus price was greater than the PJM/HUDS interface price, the average hourly price difference was $25.80. When the PJM/HUDS interface price was greater than the NYISO/Hudson bus price, the average price difference was $34.10.

37 In the first nine months of 2014, there were 4,840 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $111.11 while the NYISO LMP at the Hudson Bus during non-zero flows was $114.83, a difference of $3.72.

38 The average hourly flow during the first nine months of 2014, ignoring hours with no flow, on the Hudson line was -260 MW.

Figure 9-9 Hudson hourly average flow: January through September, 2014



Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include implemented operating agreements with MISO and the NYISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., and a reliability coordination agreement with VACAR South.

PJM and MISO Joint Operating Agreement[39]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes

39 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed October 15, 2014).

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. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[40]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses ten buses within MISO to calculate the PJM/MISO interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM interface pricing point.[41]

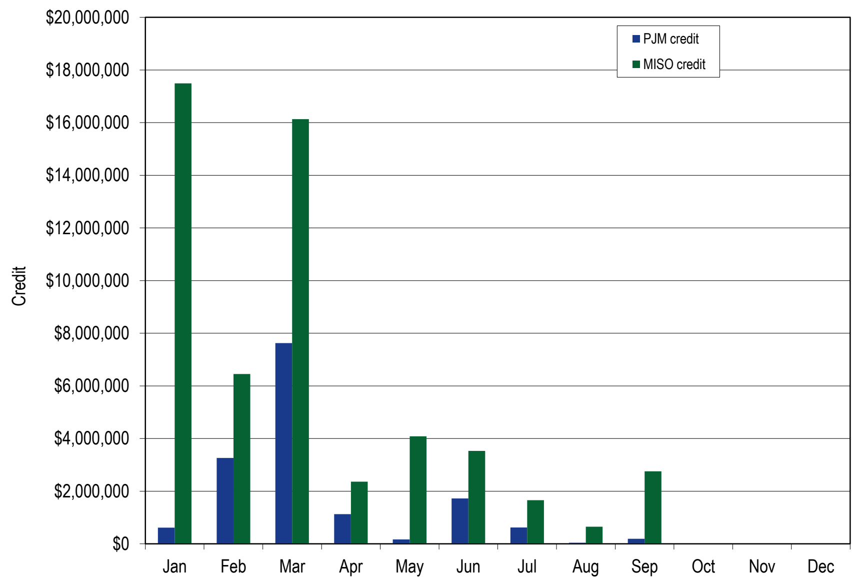
Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of January 1, 2014, PJM had 159 flowgates eligible for M2M (Market to Market) coordination. Between January 1, 2014 and September 30, 2014, PJM added 22 and deleted 92 flowgates, leaving 89 flowgates eligible for M2M coordination as of September 30, 2014. As of January 1, 2014, MISO had 265 flowgates eligible for M2M coordination. Between January 1, 2014 and September 30, 2014, MISO added 85 and deleted 76 flowgates, leaving 274 flowgates eligible for M2M coordination as of September 30, 2014. The timing of the addition of new M2M flowgates may contribute to FTR underfunding. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, contribute to FTR underfunding.

40 See www.pjm.com "2012 PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-joint-common.aspx>.
41 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

In the first nine months of 2014, the market to market operations resulted in MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-10 Credits for coordinated congestion management: January through September, 2014[42]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[43]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and NYISO each calculate an interface LMP using network models including distribution

42 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
43 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (June 15, 2014) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed October 15, 2014).

factor impacts. PJM uses two buses within NYISO to calculate the PJM/NYIS interface pricing point LMP while The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) based on the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

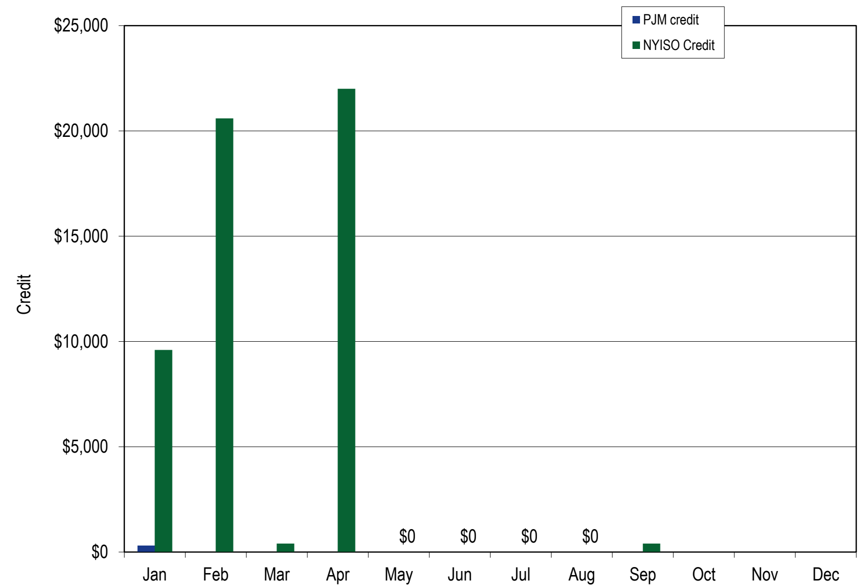
Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or NYISO, on which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by either PJM or NYISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

In the first nine months of 2014, market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The firm flow entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

In the first nine months of 2014, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch.

Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-11 Credits for coordinated congestion management (flowgates): January through September, 2014[44]



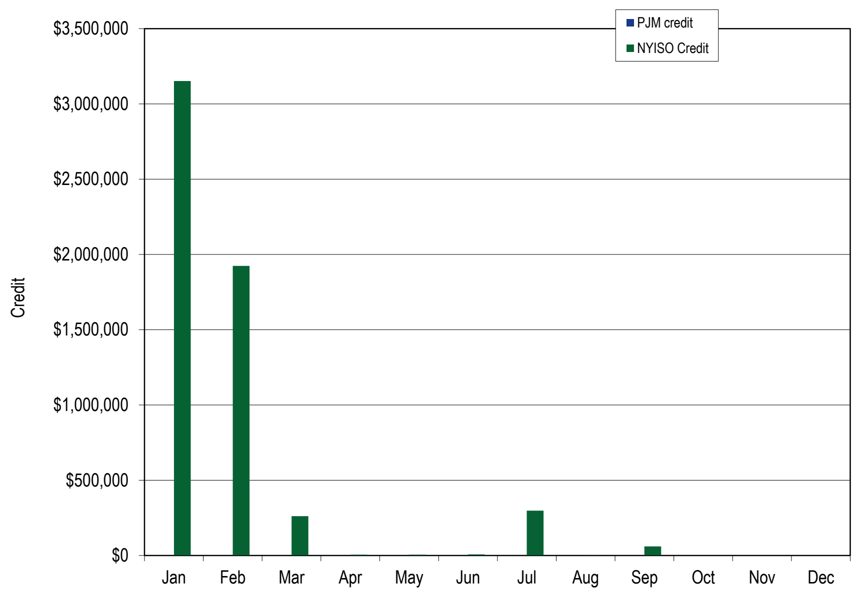
The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the PJM/NYIS border. This real-time coordination results in a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real-time to manage constraints.[45] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during

44 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

45 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (June 15, 2014) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed October 15, 2014).

coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In the first nine months of 2014, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 9-12 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

Figure 9-12 Credits for coordinated congestion management (Ramapo PARs): January through September, 2014[46]



46 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

The PJM/NYISO JOA includes a provision that allows either party to suspend M2M operations when daily congestion charges exceed $500,000. On July 8, 2013, M2M congestion charges exceeded $500,000. These congestion charges were the result of its inability to meet the Ramapo PAR target values during thunderstorm alerts (TSA) called by the NYISO. During times when actual or anticipated severe weather conditions exist in the New York City area, the NYISO issues a TSA and operates in a more conservative manner, by reducing transmission transfer limits, which affects PJM's ability to meet the PAR targets. On July 12, 2013, PJM requested the suspension of M2M coordination for all TSA flowgates. On May 2, 2014, PJM and the NYISO submitted revisions to the PJM/NYISO JOA that proposed a set of new operating requirements and settlement rules to be utilized when a TSA is in effect in New York.[47] Under the new approach, PJM and the NYISO are required to maintain flow on the ABC and JK lines to within a control band ordinarily set at +/- 100 MW of the real time market desired flows, or otherwise to attempt to direct flows by adjusting the phase angle at least twice every 15 minutes. PJM and MISO are required to maintain flow on the Ramapo PARs at or above the target into New York, or otherwise to take at least two taps every 15 minutes. Under these revised rules, PJM will not be subject to an M2M Ramapo PAR settlement obligation as long as it satisfies the operating requirements on the JK PARs. Additionally, PJM will not be subject to an M2M Ramapo PAR settlement obligation if the NYISO fails to satisfy the operating requirements on the ABC or Ramapo PARs. The NYISO will not be subject to an M2M Ramapo PAR settlement obligation as long as it satisfies the operating requirements on the ABC and Ramapo PARs. In short, if both RTOs follow the operating requirements for the PARs for which they are responsible, there will be no M2M Ramapo PAR settlements during a TSA. On June 4, 2014, FERC accepted the proposed JOA modifications with an effective date of June 11, 2014.[48]

PJM, MISO and TVA Joint Reliability Coordination Agreement (JRCA)

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion

47 See *New York Independent System Operator, Inc. and PJM Interconnection, L.L.C* Docket No. ER14-1868 (May 2, 2014).
48 See *New York Independent System Operator, Inc. and PJM Interconnection, L.L.C* Docket No. ER14-1868 (June 4, 2014).

relief among the wholesale electricity markets of MISO and PJM and the service territory of TVA. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers. The parties meet on a yearly basis. The agreement continued to be in effect in the first nine months of 2014.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[49] On January 20, 2011, the Commission conditionally accepted the compliance filing.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[50] On October 3, 2014, Duke Energy Progress (DEP) and PJM submitted revisions to the JOA to include a new Appendix B, update references to DEP's current legal name, and incorporate other revisions.[51] The MMU submitted a protest to this filing noting that the existing JOA depends on the specific characteristics of PEC as a standalone company, and the assumptions reflected in the current JOA no longer apply under the DEP joint dispatch agreement.[52] As noted in the 2010 filing, "the terms and conditions of the bilateral agreement among PEC and PJM are grounded in an appreciation of their respective systems as they exist at the time of the effective date of the JOA, but they fully expect that evolving circumstances, protocols and requirements will require that they negotiate, in good faith, a response to such changes."[53] The joint dispatch agreement changed the unique operational relationship that existed when the congestion management protocol was established. However, the merged company has not engaged in discussions with PJM as to whether the congestion management protocol that was "tailored to their [PJM and PEC] unique operational relationship" is still appropriate, or whether the congestion management protocol needs to be revised. The existing JOA does not apply to the merged company and should be terminated. The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement continued to be in effect in the first nine months of 2014.

Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[54] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

49 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).
50 See "Duke Energy Carolinas, LLC, Carolina Power & Light tariff filing," Docket No. ER12-1338-000 (July 12, 2012) and "Duke Energy Carolinas, LLC, Carolina Power & Light Joint Dispatch Agreement filing," Docket No. ER12-1343-000 (July 11, 2012).
51 See *Duke Energy Progress, Inc. and PJM Interconnection, L.L.C*, Docket No. ER15-29-000 (October 3, 2014).
52 See Protest and Motion for Rehearing of the Independent Market Monitor for PJM in Docket No. ER15-29-000 (October 24, 2014).
53 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.C.C. and Progress Energy Carolinas, Inc., Docket No. ER10-713-000 (March 10, 2010) at 2. Section 3.3 of the PJM-Progress JOA.
54 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

Table 9-26 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2014

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$48.24	$49.60	$46.24	$46.24	$2.01	$3.36
PEC	$49.08	$51.71	$46.24	$46.24	$2.84	$5.48
NCMPA	$48.99	$49.22	$46.24	$46.24	$2.75	$2.98

Table 9-27 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2014

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$48.78	$50.08	$46.03	$45.97	$2.75	$4.11
PEC	$50.69	$51.83	$46.03	$45.97	$4.66	$5.86
NCMPA	$49.53	$49.64	$46.03	$45.97	$3.50	$3.67

Other Agreements with Bordering Areas

Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey including lines controlled by PJM.[55] This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001.[56]

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009, a settlement on behalf of the parties to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[57] By order issued September 16, 2010, the Commission approved this settlement,[58] which extends Con Edison's special protocol indefinitely. The Commission approved transmission service agreements provide for Con Edison to take firm point-to-point service going forward under the PJM OATT. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU, that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[59] The settlement defined Con Edison's cost responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. Con Edison is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent roll over of the service.[60] Con Edison's rolled over service became effective on May 1, 2012. At that time, Con Edison became responsible for the entire 1,000 MW of transmission service and all associated charges and credits.

On December 11, 2013, the PJM Board approved changes to the Regional Transmission Expansion Plan (RTEP), which included approximately $1.5 billion in additional baseline transmission enhancements and expansions.[61] On January 10, 2014, in accordance with Schedule 12 of the PJM Tariff,[62] PJM filed cost assignments for those upgrades. Using the hybrid cost allocation methodology approved by the Commission in Docket No. ER13-90-000 on March 22, 2013, PJM calculated Con Edison's cost responsibility assignment as approximately $629 million. On February 10, 2014, Con Edison filed a protest to the cost allocation proposal.[63] Con Edison asserted that the cost allocation proposal is not permitted under the service agreement for transmission service under the PJM Tariff and related settlement agreement, and that PJM's allocation of costs of the PSE&G upgrade to the Con Edison zone is unjust and unreasonable. On March 7, 2014, PJM submitted a motion for leave to answer and limited answer to the protest submitted by Con Edison.[64] PJM's response points out that the filed and approved RTEP cost allocation process

55 See "Section 4 – Energy Market Uplift" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.
56 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.
57 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.
58 132 FERC ¶ 61,221 (2010).
59 *See, e.g.,* Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).
60 The terms of the settlement state that Con Edison shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.
61 See the *2013 State of the Market Report for PJM*, Volume II, Section 12, "Planning," for a more detailed discussion.
62 See PJM OATT, Schedule 12, Transmission Enhancement Charges, (February 1, 2013) pp 581-595.
63 See *Consolidated Edison Company of New York, Inc.* Docket No. ER14-972-000 (February 10, 2014).
64 See *PJM Interconnection L.L.C.* Docket No. ER14-972-000 (March 7, 2014).

was followed, and that Con Edison's cost assignment responsibilities were addressed by the Settlement agreement and Schedule 12 of the PJM Tariff.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

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

PJM issued five TLRs of level 3a or higher in the first nine months of 2014, compared to 45 such TLRs issued in the first nine months of 2013.[65] The number of different flowgates for which PJM declared a TLR 3a or higher decreased from 23 in the first nine months of 2013 to four in the first nine months of 2014. The total MWh of transaction curtailments decreased by 97.6 percent from 133,869 MWh in the first nine months of 2013 to 3,104 MWh in the first nine months of 2014.

MISO issued 124 TLRs of level 3a or higher in the first nine months of 2014, compared to 285 such TLRs issued in the first nine months of 2013. The number of different flowgates for which MISO declared a TLR 3a or higher decreased from 77 in the first nine months of 2013 to 32 in the first nine months of 2014. The total MWh of transaction curtailments decreased by 56.4 percent from 593,751 MWh in the first nine months of 2013 to 258,945 MWh in the first nine months of 2014.

NYISO issued two TLRs of level 3a or higher in the first nine months of 2014, compared to 3 such TLRs issued in the first nine months of 2013. The number of different flowgates for which NYISO declared a TLR 3a or higher increased from 1 in the first nine months of 2013 to two in the first nine months of 2014. The total MWh of transaction curtailments decreased by 80.8 percent from 5,147 MWh in the first nine months of 2013 to 991 MWh in the first nine months of 2014.

65 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2013 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

Table 9-28 PJM MISO, and NYISO TLR procedures: January, 2011 through September, 2014

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-11	7	8	29	5	5	4	75,057	14,071	156,508
Feb-11	6	7	10	5	4	2	6,428	23,796	27,649
Mar-11	0	14	28	0	5	3	0	10,133	57,472
Apr-11	3	23	12	3	9	3	8,129	44,855	15,761
May-11	9	15	15	4	7	4	18,377	36,777	24,857
Jun-11	15	14	24	7	6	9	17,865	19,437	31,868
Jul-11	7	8	17	4	7	7	18,467	3,697	20,645
Aug-11	4	6	4	4	4	2	3,624	11,323	12,579
Sep-11	7	17	7	6	7	3	6,462	25,914	11,445
Oct-11	4	16	5	2	6	1	16,812	27,392	3,665
Nov-11	0	10	2	0	5	2	0	22,672	484
Dec-11	0	5	8	0	3	2	0	8,659	26,523
Jan-12	1	9	5	1	6	2	4,920	6,274	8,058
Feb-12	4	6	16	2	6	2	0	5,177	35,451
Mar-12	1	11	10	1	6	2	398	31,891	26,761
Apr-12	0	14	11	0	7	1	0	8,408	29,911
May-12	2	17	12	1	10	5	3,539	30,759	21,445
Jun-12	0	24	0	0	7	0	0	31,502	0
Jul-12	11	19	1	5	4	1	34,197	46,512	292
Aug-12	8	13	0	1	6	0	61,151	13,403	0
Sep-12	2	5	0	1	4	0	21,134	12,494	0
Oct-12	3	9	0	2	6	0	0	12,317	0
Nov-12	4	10	5	2	6	2	444	24,351	6,250
Dec-12	1	22	0	1	12	0	0	17,761	0
Jan-13	4	42	2	3	17	1	13,453	103,463	1,045
Feb-13	4	26	0	3	10	0	14,609	66,086	0
Mar-13	0	39	0	0	13	0	0	53,122	0
Apr-13	1	45	0	1	20	0	84	64,938	0
May-13	10	29	0	7	14	0	879	20,778	0
Jun-13	4	25	1	1	11	1	5,036	76,240	4,102
Jul-13	12	28	0	2	9	0	88,623	80,328	0
Aug-13	4	19	0	4	8	0	3,469	38,608	0
Sep-13	6	33	0	5	14	0	7,716	90,188	0
Oct-13	2	42	0	1	20	0	534	72,121	0
Nov-13	2	27	0	2	8	0	11,561	52,508	0
Dec-13	0	16	0	0	5	0	0	20,257	0
Jan-14	3	19	0	3	10	0	1,852	11,683	0
Feb-14	0	29	1	0	10	1	0	33,189	991
Mar-14	0	11	0	0	7	0	0	14,842	0
Apr-14	0	6	0	0	3	0	0	1,233	0
May-14	0	9	0	0	4	0	0	53,153	0
Jun-14	0	19	0	0	7	0	0	24,614	0
Jul-14	1	13	1	1	6	1	317	26,616	0
Aug-14	0	7	0	0	3	0	0	6,319	0
Sep-14	1	11	0	1	4	0	935	87,296	0

Table 9-29 Number of TLRs by TLR level by reliability coordinator: January through September, 2014

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2014	MISO	56	38	1	15	14	0	124
	NYIS	2	0	0	0	0	0	2
	ONT	3	0	0	0	0	0	3
	PJM	3	2	0	0	0	0	5
	SOCO	4	1	0	0	0	0	5
	SWPP	198	61	0	38	27	0	324
	TVA	23	35	2	20	24	0	104
	VACS	7	15	2	2	0	0	26
Total		296	152	5	75	65	0	593

Up-To Congestion

The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the Real-Time Energy Market.[66]

Following elimination of the requirement to procure and pay for transmission for up-to congestion transactions, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased by 80.1 percent, from 105,472 bids per day in the first nine months of 2013 to 189,997 bids per day in the first nine months of 2014. The average cleared volume of up-to congestion bids increased by 22.6 percent, from 1,221,114 MWh per day in the first nine months of 2013 to 1,496,675 MWh per day in the first nine months of 2014. But the increases all occurred prior to September 8, 2014, after which the number and volume of bids declined sharply.

Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Despite that, up-to congestion transactions do not pay operating reserves charges. Up-to congestion transactions also significantly affect FTR funding.[67]

On August 29, 2014, FERC issued an Order Instituting Section 206 Proceeding and Establishing Procedures which, among other things, created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[68] In the Order, FERC directed the Commission staff to convene a technical conference to determine how uplift is allocated to all virtual transactions, including up-to congestion transactions.

As a result of the requirement to pay uplift charges and the uncertainty about the level of the required uplift charges, market participants reduced up-to congestion trading effective September 8, 2014. The average number of up-to congestion bids submitted in the Day-Ahead Energy Market decreased by 79.5 percent, from 192,097 bids per day in three week period prior to the September 8, 2014, refund effective date to 39,429 bids per day in three week period following the September 8, 2014, refund effective date. The average cleared volume of up-to congestion bids decreased by 79.9 percent, from 1,633,746 MWh per day in the in three week period prior to the September 8, 2014, refund effective date to 328,041 MWh per day in three week period following the September 8, 2014, refund effective date (See Figure 9-13).

66 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

67 For more information on up-to congestion transaction impacts on FTRs, see the *2014 Quarterly State of the Market Report for PJM: January through September*, Volume 2, Section 13: FTRs and ARRs, "FTR Forfeitures".

68 *Order Instituting Section 206 Proceeding and Establishing Procedures*, 148 FERC ¶ 61,144 (2014).

Figure 9-13 Monthly up-to congestion cleared bids in MWh: January, 2005 through September, 2014

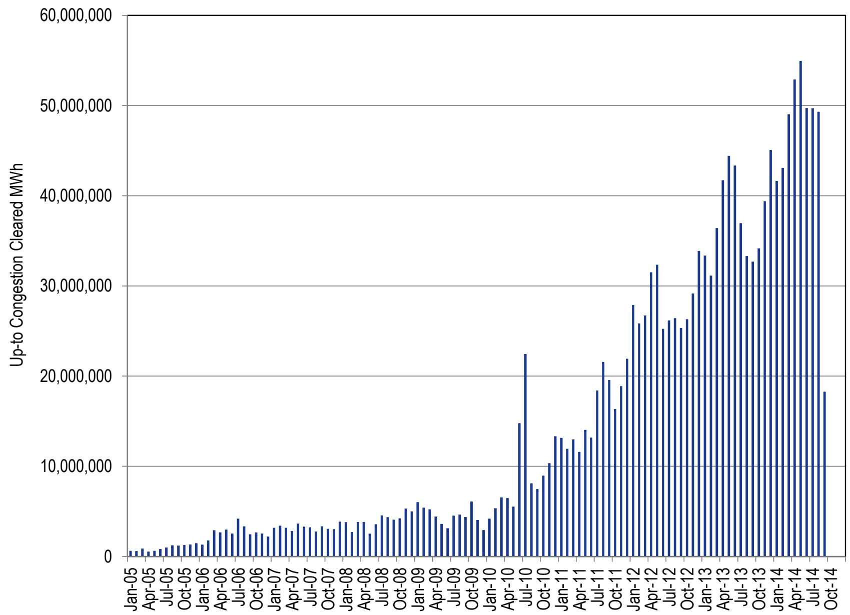


Table 9-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through September, 2014

	Bid MW					Bid Volume					Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-09	4,218,910	5,787,961	319,122	-	10,325,993	90,277	74,826	6,042	-	171,145	2,591,211	3,242,491	202,854	-	6,036,556	56,132	45,303	4,210	-	105,645
Feb-09	3,580,115	4,904,467	318,440	-	8,803,022	64,338	70,874	6,347	-	141,559	2,374,734	2,836,344	203,907	-	5,414,985	42,101	44,423	4,402	-	90,926
Mar-09	3,649,978	5,164,186	258,701	-	9,072,865	64,714	72,495	5,531	-	142,740	2,285,412	2,762,459	178,507	-	5,226,378	42,408	42,007	4,299	-	88,714
Apr-09	2,607,303	5,085,912	73,931	-	7,767,146	47,970	67,417	2,146	-	117,533	1,797,302	2,582,294	48,478	-	4,428,074	32,088	35,987	1,581	-	69,656
May-09	2,196,341	4,063,887	106,860	-	6,367,088	40,217	54,745	1,304	-	96,266	1,496,396	2,040,737	77,553	-	3,614,686	26,274	29,720	952	-	56,946
Jun-09	2,598,234	3,132,478	164,903	-	5,895,615	47,625	44,755	2,873	-	95,253	1,540,169	1,500,560	88,723	-	3,129,452	28,565	23,307	1,522	-	53,394
Jul-09	3,984,680	3,776,957	296,910	-	8,058,547	67,039	56,770	5,183	-	128,992	2,465,891	1,902,807	163,129	-	4,531,826	41,924	31,176	2,846	-	75,946
Aug-09	3,551,396	4,388,435	260,184	-	8,200,015	64,652	64,052	3,496	-	132,200	2,278,431	2,172,133	194,415	-	4,644,978	41,774	34,576	2,421	-	78,771
Sep-09	2,948,353	4,179,427	156,270	-	7,284,050	51,006	64,103	2,405	-	117,514	1,774,589	2,479,898	128,344	-	4,382,831	31,962	40,698	1,944	-	74,604
Oct-09	3,172,034	6,371,230	154,825	-	9,698,089	46,989	100,350	2,217	-	149,556	2,060,371	3,931,346	110,646	-	6,102,363	31,634	70,964	1,672	-	104,270
Nov-09	3,447,356	3,851,334	103,325	-	7,402,015	53,067	61,906	1,236	-	116,209	2,065,813	1,932,595	51,929	-	4,050,337	33,769	32,916	653	-	67,338
Dec-09	2,323,383	2,502,529	66,497	-	4,892,409	47,099	47,223	1,430	-	95,752	1,532,579	1,359,936	34,419	-	2,926,933	31,673	28,478	793	-	60,944
Jan-10	3,794,946	3,097,524	212,010	-	7,104,480	81,604	55,921	3,371	-	140,896	2,250,689	1,789,018	161,977	-	4,201,684	49,064	33,640	2,318	-	85,022
Feb-10	3,841,573	3,937,880	316,150	-	8,095,603	80,876	80,685	2,269	-	163,830	2,627,101	2,435,650	287,162	-	5,349,913	50,958	48,008	1,812	-	100,778
Mar-10	4,877,732	4,454,865	277,180	-	9,609,777	97,149	74,568	2,239	-	173,956	3,209,064	3,071,712	263,516	-	6,544,292	60,277	48,596	2,064	-	110,937
Apr-10	3,877,306	5,558,718	210,545	-	9,646,569	67,632	85,358	1,573	-	154,563	2,622,113	3,690,889	170,020	-	6,483,022	42,635	54,510	1,154	-	98,299
May-10	3,800,870	5,062,272	149,589	-	9,012,731	74,996	78,426	1,620	-	155,042	2,366,149	3,049,405	112,700	-	5,528,253	47,505	48,996	1,112	-	97,613
Jun-10	9,126,963	9,568,549	1,159,407	-	19,854,919	95,155	89,222	6,960	-	191,337	6,863,803	6,850,098	1,072,759	-	14,786,660	59,733	55,574	5,831	-	121,138
Jul-10	12,818,141	11,526,089	5,420,410	-	29,764,640	124,929	106,145	18,948	-	250,022	8,971,914	8,237,557	5,241,264	-	22,450,734	73,232	60,822	16,526	-	150,580
Aug-10	8,231,393	6,767,617	888,591	-	15,887,601	115,043	87,876	10,664	-	213,583	4,430,832	2,894,314	785,726	-	8,110,871	62,526	40,485	8,884	-	111,895
Sep-10	7,768,878	7,561,624	349,147	-	15,679,649	184,697	161,929	4,653	-	351,279	3,915,814	3,110,580	256,039	-	7,282,433	63,405	45,264	3,393	-	112,062
Oct-10	8,732,546	9,795,666	476,665	-	19,004,877	189,748	154,741	7,384	-	351,873	4,150,104	4,564,039	246,594	-	8,960,736	76,042	65,223	3,670	-	144,935
Nov-10	11,636,949	9,272,885	537,369	-	21,447,203	253,594	170,470	9,366	-	433,430	5,765,905	4,312,645	275,111	-	10,353,661	112,250	71,378	4,045	-	187,673
Dec-10	17,769,014	12,863,875	923,160	-	31,556,049	307,716	215,897	15,074	-	538,687	7,851,235	5,150,286	337,157	-	13,338,678	136,582	93,299	7,380	-	237,261
Jan-11	20,275,932	11,807,379	921,120	-	33,004,431	351,193	210,703	17,632	-	579,528	7,917,986	4,925,310	315,936	-	13,159,232	151,753	91,557	8,417	-	251,727
Feb-11	18,418,511	13,071,483	800,630	-	32,290,624	345,227	226,292	17,634	-	589,153	6,806,039	4,879,207	248,573	-	11,933,818	151,003	99,302	8,851	-	259,156
Mar-11	17,330,353	12,919,960	749,276	-	30,999,589	408,628	274,709	15,714	-	699,051	7,104,642	5,603,583	275,682	-	12,983,906	178,620	124,990	7,760	-	311,370
Apr-11	17,215,352	9,321,117	954,283	-	27,490,752	513,881	265,334	17,459	-	796,674	7,452,366	3,797,819	351,984	-	11,602,168	229,707	113,610	8,118	-	351,435
May-11	21,058,071	11,204,038	2,937,898	-	35,200,007	562,819	304,589	24,834	-	892,242	8,294,422	4,701,077	1,031,519	-	14,027,018	261,355	143,956	11,116	-	416,427
Jun-11	20,455,508	12,125,806	395,833	-	32,977,147	524,072	285,031	12,273	-	821,376	7,632,235	5,361,825	198,482	-	13,192,543	226,747	132,744	6,363	-	365,854
Jul-11	24,273,892	16,837,875	409,863	-	41,521,630	603,519	338,810	13,781	-	956,110	9,585,027	8,617,284	205,599	-	18,407,910	283,287	186,866	7,008	-	477,161
Aug-11	23,790,091	21,014,941	229,895	-	45,034,927	591,170	403,269	8,278	-	1,002,717	10,594,771	10,875,384	103,141	-	21,573,297	274,398	208,593	3,648	-	486,639
Sep-11	21,740,208	18,135,378	232,626	-	40,108,212	526,945	377,158	7,886	-	911,989	10,219,806	9,270,121	82,200	-	19,572,127	270,088	185,585	3,444	-	459,117
Oct-11	20,240,161	19,476,556	333,077	-	40,049,794	540,877	451,507	8,609	-	1,000,993	8,376,208	7,853,947	126,718	-	16,356,873	255,206	198,778	4,236	-	458,220
Nov-11	27,007,141	28,994,789	507,788	-	56,509,718	594,397	603,029	13,379	-	1,210,805	9,064,570	9,692,312	131,670	-	18,888,552	254,851	256,270	5,686	-	516,807
Dec-11	34,990,790	34,648,433	531,616	-	70,170,839	697,524	655,222	14,187	-	1,366,933	11,738,910	10,049,685	137,689	-	21,926,284	281,304	248,008	6,309	-	535,621
Jan-12	38,906,228	36,928,145	620,448	-	76,454,821	745,424	689,174	16,053	-	1,450,651	13,610,725	14,120,791	145,773	-	27,877,288	289,524	304,072	5,078	-	598,674
Feb-12	37,231,115	36,736,507	323,958	-	74,291,580	739,200	724,477	8,572	-	1,472,249	12,883,355	12,905,553	54,724	-	25,843,632	299,055	276,563	2,175	-	577,793
Mar-12	38,824,528	39,163,001	297,895	-	78,285,424	802,983	842,857	8,971	-	1,654,811	13,328,968	13,306,689	89,262	-	26,724,918	320,210	320,252	3,031	-	643,493
Apr-12	42,085,326	44,565,341	436,632	-	87,087,299	884,004	917,430	12,354	-	1,813,788	15,050,798	16,297,303	171,252	-	31,519,354	369,273	355,669	4,655	-	729,597
May-12	44,436,245	43,888,405	489,938	-	88,814,588	994,735	885,319	10,294	-	1,890,348	17,416,386	14,733,838	189,667	-	32,339,891	434,919	343,872	4,114	-	782,905
Jun-12	38,962,548	32,828,393	975,776	-	72,766,718	872,764	684,382	21,781	-	1,578,927	12,675,852	12,311,609	250,024	-	25,237,485	355,731	295,911	6,891	-	658,533
Jul-12	45,565,682	41,589,191	855,676	-	88,010,549	1,077,721	911,300	27,173	-	2,016,194	13,001,225	12,823,361	348,946	-	26,173,532	399,135	321,062	9,958	-	730,155
Aug-12	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
Oct-12	35,567,607	42,489,970	1,415,992	-	79,473,570	908,200	1,048,029	46,802	-	2,003,031	11,969,576	13,949,871	392,286	-	26,311,733	345,788	376,513	14,089	-	736,390
Nov-12	24,795,325	25,498,103	1,258,755	52,022,007	103,574,190	542,992	614,349	43,829	1,631,255	2,832,425	6,517,798	7,872,496	286,535	14,482,701	29,159,529	186,492	245,943	15,042	509,436	956,913
Dec-12	22,597,985	22,560,837	1,727,510	84,548,868	131,435,199	489,208	515,873	55,376	2,767,292	3,827,749	5,116,607	6,350,080	454,289	21,958,089	33,879,065	180,592	224,830	24,459	820,991	1,250,872
Jan-13	16,718,393	21,312,321	2,010,317	76,937,535	116,978,566	422,501	527,037	63,227	2,115,649	3,128,414	4,115,418	5,820,177	522,459	22,906,008	33,364,063	149,282	199,123	23,926	657,602	1,029,933
Feb-13	12,567,004	15,509,978	1,477,275	67,258,116	96,812,373	352,963	400,563	43,133	1,798,434	2,595,093	3,019,380	4,356,113	461,615	23,311,066	31,148,173	110,397	158,085	15,892	669,364	953,738
Mar-13	14,510,721	17,019,755	1,601,487	88,109,152	121,241,114	372,402	402,711	48,112	1,959,294	2,782,519	3,868,303	4,743,283	358,180	27,439,606	36,409,373	131,506	166,295	17,884	774,020	1,089,705
Apr-13	14,538,907	17,419,505	1,337,680	105,927,107	139,223,200	358,245	364,008	47,048	2,275,846	3,045,147	4,413,047	4,834,302	315,867	32,152,243	41,715,459	145,860	157,031	16,315	892,562	1,211,768
May-13	16,565,868	17,640,682	1,640,097	115,572,648	151,419,296	431,892	389,254	54,873	2,660,793	3,536,812	4,556,277	4,747,887	333,677	34,778,962	44,416,803	144,444	144,482	16,317	944,116	1,249,359
Jun-13	16,698,203	18,904,971	1,337,373	128,595,957	165,536,504	452,145	433,010	48,007	3,384,811	4,317,973	3,823,166	4,280,538	312,158	34,935,141	43,351,002	143,223	151,603	17,518	1,116,318	1,428,662
Jul-13	15,436,914	16,428,662	1,473,144	116,673,912	150,012,631	430,120	387,969	49,712	3,075,624	3,943,425	3,250,706	3,502,990	320,374	29,883,430	36,957,500	131,535	127,032	17,948	957,260	1,233,775
Aug-13	12,332,984	14,354,140	1,370,624	89,306,595	117,364,344	328,835	326,637	40,325	2,223,269	2,919,066	2,862,764	3,232,565	309,069	26,900,995	33,305,393	111,715	122,061	16,299	848,490	1,098,565
Sep-13	10,767,257	11,322,974	729,332	75,686,010	98,505,573	264,095	262,486	21,968	1,976,741	2,525,290	2,962,619	3,467,611	221,329	26,044,742	32,696,300	102,984	107,604	10,233	792,766	1,013,587
Oct-13	9,081,257	11,106,943	853,397	86,857,535	107,899,131	280,821	338,374	31,031	2,524,127	3,174,353	2,201,219	3,532,253	186,113	28,243,584	34,163,168	108,189	145,667	11,551	1,002,832	1,268,239
Nov-13	9,219,216	15,052,563	1,307,989	98,027,480	123,607,248	267,704	394,031	39,095	3,167,638	3,868,468	2,640,001	3,986,788	332,814	32,437,908	39,397,511	112,850	154,379	13,958	1,238,589	1,519,776
Dec-13	9,934,234	16,089,101	1,696,981	118,916,149	146,636,465	286,295	404,788	42,367	3,691,770	4,425,220	3,189,261	3,234,196	503,666	38,150,077	45,077,200	119,954	122,683	14,318	1,382,736	1,639,691
Jan-14	10,359,891	16,047,391	2,326,490	119,848,848	148,582,620	350,248	469,176	47,801	4,382,482	5,249,707	2,594,374	3,172,914	460,495	35,413,440	41,641,223	116,316	143,021	15,323	1,537,418	1,812,078
Feb-14	11,351,094	14,846,332	1,854,617	126,008,272	154,060,316	382,148	480,055	47,526	5,151,647	6,061,376	2,764,565	3,247,481	362,670	36,715,916	43,090,631	132,870	147,766	14,045	1,897,337	2,192,018
Mar-14	14,669,735	17,135,117	1,949,978	147,142,336	180,897,166	515,877	516,871	54,575	7,026,221	8,113,544	3,442,624	3,293,865	341,620	41,962,312	49,040,421	165,663	148,671	15,214	2,290,716	2,620,264
Apr-14	12,056,167	15,453,126	1,744,523	132,691,464	161,945,280	408,540	404,498	48,279	5,179,680	6,040,997	3,037,393	3,483,465	347,165	46,018,100	52,886,123	136,314	129,838	12,743	2,036,904	2,315,799
May-14	14,145,892	17,305,057	2,132,591	153,504,853	187,088,393	456,708	452,060	54,954	5,628,483	6,592,205	3,077,932	4,477,545	319,825	47,071,415	54,946,717	136,627	162,321	14,724	1,960,618	2,274,290
Jun-14	13,404,498	13,716,736	1,499,317	141,004,417	169,624,968	407,769	372,275	44,035	5,095,316	5,919,395	3,598,712	3,000,215	349,700	42,767,010	49,715,637	137,256	115,610	16,994	1,732,262	2,002,122
Jul-14	11,820,001	11,811,311	1,278,719	133,179,154	158,089,185	396,433	388,463	38,402	5,021,819	5,845,117	3,541,889	3,118,746	336,003	42,702,334	49,698,971	143,527	131,968	13,699	1,834,684	2,123,878
Aug-14	10,808,911	12,150,513	874,609	135,912,394	159,746,426	375,703	385,705	32,368	5,108,340	5,902,116	3,054,727	3,315,313	140,171	42,796,063	49,306,273	146,179	139,431	11,706	1,937,025	2,234,341
Sep-14	5,105,355	5,291,842	467,670	51,226,017	62,090,885	174,241	156,046	18,095	1,796,453	2,144,835	1,500,083	1,232,520	103,304	15,430,477	18,266,384	73,100	56,651	5,915	735,658	871,324
TOTAL	1,118,184,641	1,119,017,635	63,459,847	2,444,956,826	4,745,618,949	26,482,951	24,562,848	1,522,961	79,642,984	132,211,744	398,017,509	392,596,508	23,815,282	744,501,618	1,558,930,918	10,692,413	9,784,552	590,812	28,569,704	49,637,481

In the first nine months of 2014, the cleared MW volume of up-to congestion transactions was comprised of 6.5 percent imports, 6.9 percent exports, 0.7 percent wheeling transactions and 85.9 percent internal transactions. Only 0.1 percent of the up-to congestion transactions had matching real-time energy market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load which can create loop flows and inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM Energy Market, at the PJM/NYIS Interface regardless of the submitted market path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT market path, and a second segment on the ONT-MISO-PJM market path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source is Ontario (the ONT Interface price).

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.

Elimination of Ontario Interface Pricing Point

An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy.

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[69] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. Transactions between PJM and external balancing authorities need to be priced at the PJM border.

The IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

The IMO interface pricing point is defined as the LMP at the Bruce bus, which is located in IESO. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The non-contiguous nature of the Ontario interface pricing point creates overpayments or additional credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. Of the 3,690 GWh of the net scheduled transactions between PJM and IESO, 3,598 GWh wheeled through MISO in the first nine months of 2014 (see Table 9-22).

The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point.[70]

69 See "Interface Pricing Point Assignment Methodology," (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx> (Accessed October 16, 2014). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

70 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

PJM and NYISO Coordinated Interchange Transaction Proposal

The coordinated transaction scheduling (CTS) proposal provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated. The evaluation will be based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price from the ITSCED results with the NYISO. The NYISO compares the PJM/NYISO Interface Price with its RTC calculated NYISO/PJM Interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

On December 13, 2013, PJM submitted proposed revisions to the PJM Operating Agreement, and parallel provisions of the PJM Tariff, to implement CTS.[71] This filing requested that the Commission issue an order accepting the proposed revisions by no later than February 13, 2014 to allow for adequate time to develop the infrastructure necessary to implement CTS in November, 2014. The Commission issued an order conditionally accepting the tariff revisions on February 20, 2014, for implementation on the later of November, 2014, or the date that CTS becomes operational, subject to the submission of an informational filing informing the Commission of the acceptance of ITSCED forecasting accuracy standards, and an additional revised tariff no later than fourteen days prior to the official implementation date of CTS.[72]

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for the first nine months of 2014.[73] Table 9-30 shows that over all forecast ranges ITSCED predicted the real-time PJM/NYIS interface LMP within the range of \$0.00 to \$5.00 in 28.1 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was \$1.80. In 10.1 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than \$20.00, with an average price difference of \$109.26, and in 11.0 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was greater than -\$20.00, with an average price difference of \$90.41.

71 See PJM Interconnection, L.L.C., OA Schedule 1 and Attachment K Revisions, Docket No. ER14-623-000. (December 13, 2013).
72 146 FERC ¶ 61,096 (2014).
73 See the *2014 Quarterly State of the Market Report for PJM: January through March*, Section 9, "PJM and NYISO Coordinated Interchange Transaction Proposal" for ITSCED accuracy statistics for the calendar year 2013.

Table 9-31 ITSCED/real-time LMP - PJM/NYIS interface price comparison (all intervals): January through September, 2014

Range	Percent of All Intervals	Average Price Difference
> \$20	10.1%	\$109.26
\$10 to \$20	4.9%	\$14.26
\$5 to \$10	6.6%	\$7.05
\$0 to \$5	28.1%	\$1.80
-\$5 to \$0	27.4%	\$1.84
-\$10 to -\$5	6.8%	\$7.07
-\$20 to -\$10	5.1%	\$14.24
< -\$20	11.0%	\$90.41

The ITSCED application runs approximately every 5 minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. Table 9-32 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time.

Table 9-32 ITSCED/real-time LMP - PJM/NYIS interface price comparison (by interval): January through September, 2014

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	12.4%	$101.37	9.4%	$98.04	7.5%	$94.53	10.0%	$124.23
$10 to $20	5.8%	$14.31	4.9%	$14.29	4.1%	$14.08	4.4%	$14.31
$5 to $10	7.0%	$7.08	6.9%	$7.05	6.4%	$6.97	6.1%	$7.00
$0 to $5	25.5%	$1.89	28.6%	$1.87	30.4%	$1.75	30.3%	$1.69
-$5 to $0	25.9%	$1.95	26.8%	$1.87	28.7%	$1.75	28.5%	$1.76
-$10 to -$5	7.3%	$7.03	6.9%	$7.08	6.6%	$7.06	6.2%	$7.09
-$20 to -$10	5.2%	$14.21	5.0%	$14.31	5.3%	$14.23	4.8%	$14.38
< -$20	10.9%	$95.48	11.5%	$93.98	11.1%	$88.22	9.9%	$83.77

Table 9-32 shows that while there is some improvement as the forecast gets closer to real time, a substantial range of forecast errors remain even in the thirty-minute ahead forecast. In the final ITSCED results prior to real time, in 58.8 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 51.4 percent in the 135 minute ahead ITSCED results.

In 19.9 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00 in the thirty-minute ahead cases, the average price differences were $124.23 when the price difference was greater than $20.00, and $83.77 when the price difference was greater than -$20.00.

The NYISO will utilize PJM's ITSCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO will approve CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the ITSCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences in forecasted LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve payments are applied and CTS transactions are optional, there is no reason not to implement the CTS proposal. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be addressed to improve the efficiency of interchange transaction pricing at the PJM/NYISO seam. Minimizing this time lag is more likely to improve pricing efficiency at the PJM/NYISO border than the CTS transaction approach.

It does not appear that ITSCED can accurately predict real-time PJM/NYIS interface prices. As long as the risk associated with CTS transactions remains entirely with market participants, it is the participants who need to account for the accuracy of the forecasts.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO have proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market initiative. While the mechanics of transaction evaluation have yet to be determined, the coordinated transaction scheduling (CTS) proposal would provide the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation would be based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED).

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for the first nine months of 2014. Table 9-33 shows that over all forecast ranges ITSCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 29.8 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.73. In 8.4 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, with an average price difference of $88.83, and in 8.3 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was greater than -$20.00, with an average price difference of $82.99.

Table 9-33 ITSCED/real-time LMP - PJM/MISO interface price comparison (all intervals): January through September, 2014

Range	Percent of All Intervals	Average Price Difference
> $20	8.4%	$88.83
$10 to $20	5.6%	$14.28
$5 to $10	7.1%	$7.12
$0 to $5	29.8%	$1.73
-$5 to $0	28.9%	$1.74
-$10 to -$5	6.9%	$7.13
-$20 to -$10	5.0%	$14.09
< -$20	8.3%	$82.99

The ITSCED application runs approximately every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/MISO interface prices. Table 9-34 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time.

Table 9-34 ITSCED/real-time LMP - PJM/MISO interface price comparison (by interval): January through September, 2014

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	10.7%	$78.61	7.6%	$77.45	6.0%	$75.75	7.6%	$107.91
$10 to $20	6.2%	$14.30	5.7%	$14.30	4.9%	$14.26	5.1%	$14.14
$5 to $10	7.3%	$7.17	7.5%	$7.07	6.8%	$7.08	6.5%	$7.04
$0 to $5	27.6%	$1.81	30.7%	$1.77	31.9%	$1.69	31.2%	$1.61
-$5 to $0	27.8%	$1.83	28.2%	$1.74	30.0%	$1.65	30.0%	$1.68
-$10 to -$5	7.0%	$7.14	6.9%	$7.17	6.9%	$7.14	6.8%	$7.11
-$20 to -$10	5.1%	$14.17	4.9%	$13.98	5.0%	$14.06	4.9%	$14.03
< -$20	8.3%	$87.79	8.6%	$84.62	8.6%	$82.27	7.9%	$76.59

Table 9-34 shows that while there is some improvement as the forecast gets closer to real time, a substantial range of forecast errors remain even in the thirty-minute ahead forecast. In the final ITSCED results prior to real time, in 61.2 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 55.4 percent in the 135 minute ahead ITSCED results.

The absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00 in the thirty-minute ahead cases in 15.5 percent of all intervals, the average price difference was $107.91 when the price difference was greater than $20.00, and the average price difference was $76.59 when the price difference was greater than -$20.00.

It does not appear that ITSCED can accurately predict real-time PJM/MISO interface prices. But as long as the risk associated with CTS transactions remains entirely with market participants, it is the participants who need to account for the accuracy of the forecasts.

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 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.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations mostly addresses these concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM (Table 9-35 shows that there have been no uncollected congestion charges since the inception of the business rule change on April 12, 2013.) There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be necessary in the future to address this exposure.

Table 9-35 Monthly uncollected congestion charges: January, 2010 through September, 2014

Month	2010	2011	2012	2013	2014
Jan	$148,764	$3,102	$0	$5	$0
Feb	$542,575	$1,567	($15)	$249	$0
Mar	$287,417	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0
May	$41,025	$0	($27)	$0	$0
Jun	$169,197	$1,354	$78	$0	$0
Jul	$827,617	$1,115	$0	$0	$0
Aug	$731,539	$37	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	
Nov	$30,843	($795)	($4,678)	$0	
Dec	$127,176	($659)	($209)	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0

Spot Imports

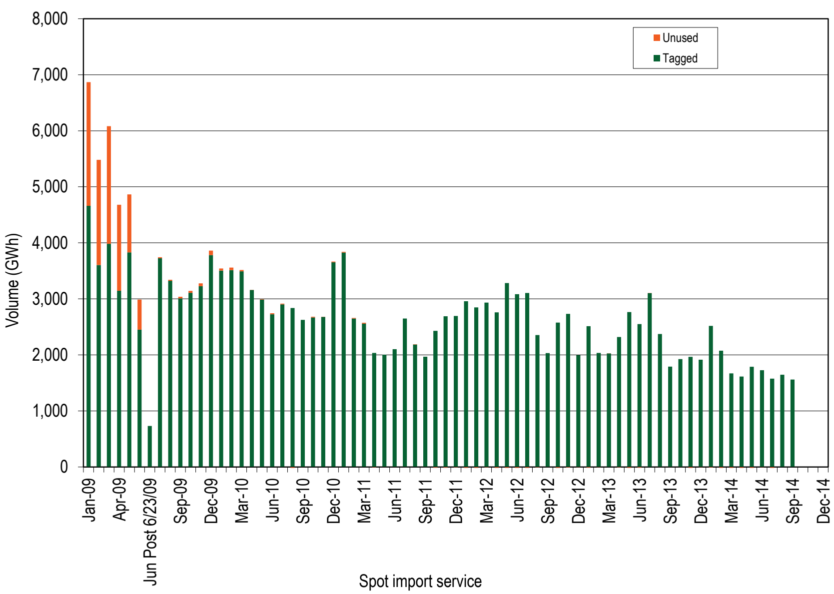
Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively willing to pay congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange. PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[74] The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

74 See "Modifications to the Practices of Non-Firm and Spot Market Import Service," (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (Accessed July 18, 2014).

The new spot import rules provided incentives to hoard spot import capability. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not associated with a valid NERC Tag within two hours when reserved the day prior to the scheduled flow, or within 30 minutes when reserved on the day of the scheduled flow. On June 23, 2009, PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage (defined as utilized on a NERC Tag) has been over 99 percent, compared to 70 percent prior to the modification (See Figure 9-14).

The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

Figure 9-14 Spot import service utilization: January, 2009 through September, 2014



Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high-load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be utilized to meet load in the most economic manner.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments all affect the duration of interchange transactions. The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is consistent with the view that the available generation in the PJM system can only move 1,000 MW over any 15 minute period. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports and exports. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intra-hour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764.[75] This order proposed to give transmission customers the ability to adjust their transmission schedules to reflect more accurate power production forecasts, load and system conditions, by requiring each public utility transmission provider to offer intra-hourly transmission scheduling. Order No. 764 required transmission providers to provide transmission customers the option to schedule transmission service at 15 minute intervals.[76]

75 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
76 Order No. 764 at P 51.

On November 12, 2013, PJM submitted its compliance filing to Order 764.[77] PJM noted that its current business practices already comply with the 15 minute scheduling interval mandate, but pointed out the 45 minute minimum duration rule that was put in place to protect against the previously observed market abuses.[78] PJM concluded that a return to a 15 minute duration rule would cause an increase in imbalance charges/Balancing Operating Reserve costs if market participants engaged in the behaviors that the 45 minute requirement eliminated.

On April 17, 2014, FERC issued its order accepting in part and rejecting in part PJM's proposed tariff revisions.[79] The Commission found that PJM's 45 minute duration rule was inconsistent with Order 764.[80]

Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule to become compliant with Order No. 764.[81,82,83]

PJM and the MMU issued a statement indicating that both remain concerned about market participants' scheduling behavior, and will continue to monitor and address any scheduling behavior that raises operational or market manipulation concerns.[84]

77 See PJM Interconnection L.L.C. filing, Docket No. ER14-383-000 (November 12, 2013).
78 See *Id.* at 5–7.
79 147 FERC ¶ 61,045 (2014).
80 *See Id.* at P 12.
81 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
82 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
83 See Letter Order, Docket No. ER14-381-000 (June 30, 2014).
84 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.pjm.com/~/media/documents/reports/20140729-pjm-imm-joint-statement-on-interchange-scheduling.ashx>.