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

- **East Kentucky Power Cooperative (EKPC).** On June 1, 2013, East Kentucky Power Cooperative was integrated into PJM. This integration eliminated the EKPC Interface. The integration did not result in any changes to interface pricing points.
- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first nine months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in January through August, and a net exporter of energy in September.[1] During the first nine months of 2013, the real-time net interchange of 4,706.7 GWh was greater than net interchange of 2,152.5 GWh in the first nine months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first nine months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. During the first nine months of 2013, the total day-ahead net interchange of -12,727.7 GWh was greater than net interchange of -5,824.8 GWh during the first nine months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2013, gross imports in the Day-Ahead Energy Market were 150.8 percent of gross imports in the Real-Time Energy Market (403.2 percent during the first nine months of 2012), gross exports in the Day-Ahead Energy Market were 218.5 percent of the gross exports in the Real-Time Energy Market (447.5 percent during the first nine months of 2012).

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.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 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 2013, there were net scheduled exports at eleven of PJM's 17 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 2013, there were net scheduled exports at ten of PJM's 21 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 2013, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead.
- **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 2013, up-to congestion transactions had net exports at seven of PJM's 19 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2013, 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. The direction of flow was consistent with price differentials in 47.0 percent of hours in the first nine months of 2013.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2013, 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 53.1 percent of the hours in the first nine months of 2013.

2 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[3] The average hourly flow during the first nine months of 2013 was -354 MW.[4] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 69.5 percent of the hours in the first nine months of 2013.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[5] The average hourly flow during the first nine months of 2013 was -127 MW.[6] The direction of flows was consistent with price differentials in 65.8 percent of the hours in the first nine months of 2013.

- **Hudson DC Line.** The Hudson direct current (DC) line began commercial operation on June 3, 2013. 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 and NYISO. While the Hudson DC line is a bidirectional line, power flows will only be from PJM to New York. In the first four months of operations, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus.[7] The average hourly flow during the first four months of operation was -22 MW.[8] The direction of flows was consistent with price differentials in 60.9 percent of the hours between June 3, 2013 and September 30, 2013.

3 In the first nine months of 2013, there were 1,128 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 $42.62 while the NYISO LMP at the Neptune Bus during non-zero flows was $64.19, a difference of $21.57.

4 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -428 MW.

5 In the first nine months of 2013, there were 1,351 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 $41.23 while the NYISO LMP at the Neptune Bus during non-zero flows was $48.95, a difference of $7.72.

6 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Linden VFT line was -161 MW.

7 In its four months of operation, there were 2,987 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $48.65 while the NYISO LMP at the Hudson Bus during non-zero flows was $55.00, a difference of $6.35.

8 The average hourly flow during the first four months of operations, ignoring hours with no flow, on the Hudson line was -120 MW.

Interchange Transaction Issues

- **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 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh. For the first nine months of 2012, net scheduled interchange was 1,051 GWh and net actual interchange was 801 GWh, a difference of 251 GWh. This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 45 TLRs of level 3a or higher in the first nine months of 2013, compared to 29 TLRs issued in the first nine months of 2012.

- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 105,472 bids per day, with an average cleared volume of 1,221,114 MWh per day, in the first nine months of 2013, compared to an average of 58,273 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012. (Figure 9-13).

- **Elimination of Ontario Interface Pricing Point.** The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing. Because 5,022 GWh of the 5,045 GWh of net transactions between PJM and IESO wheeled through MISO during the first nine months of 2013, (see Table 9-22), the MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority until the stakeholder process determines an alternative approach to pricing these transactions.

- **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.

  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 proceed with the development of 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.

- **Elimination of Sources and Sinks.** The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[9] On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction. 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.

  The MMU continues to recommend 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.

9 See "Meeting Minutes, "Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> (Accessed October 9, 2013).

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non-market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non-market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non-market areas do not include these features. The market areas are extremely transparent and the non-market areas are not transparent.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first nine months of 2013, including evolving transaction patterns, economics and issues. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint. 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 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, reducing the day-ahead gross import and export volumes. While the gross import and export volumes in the Day-Ahead Market have decreased, the net direction of power flows has remained predominantly in the export direction.

In the first nine months of 2013, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for 53.0 percent of the hours for transactions between PJM and MISO and for 46.9 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by relying on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

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 require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely as possible to the expected actual power flows would result in a more economic dispatch of the entire Eastern Interconnection.

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. The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create business rules that prevent sham scheduling among and between the RTO/ISO markets.

The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the operation of the PJM Day-Ahead Market and charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges. The level of the fee should be determined based on the method defined in the State of the Market Report.[10]

10 See the *2013 Quarterly State of the Market Report for PJM: January to September*, Section 4, "Operating Reserves."

There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast). The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the integration, 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.[11] After the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. 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 no longer accept long term positions of any kind at the NIPSCO and Southeast interface pricing points and to eliminate these interface pricing points from the Day-Ahead and Real-Time Energy Markets.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[12] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

The MMU continues to recommend 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.

Interchange Transaction Activity

Aggregate Imports and Exports

During the first nine months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in January through August, and a net exporter of energy in September (Figure 9-1).[13] During the first nine months of 2013, the total real-time net interchange of 4,706.7 GWh was greater than the net interchange of 2,152.5 GWh during the first nine months of 2012. During the first nine months of 2013, the peak month for net importing interchange was July, 1,464.4 GWh; in 2012 it was May, 798.4 GWh. Gross monthly export volumes during the first nine months of 2013 averaged 3,257.1 GWh compared to 3,639.6 GWh for the first nine months of 2012, while gross monthly imports during the first nine months of 2013 averaged 3,780.1 GWh compared to 3,878.7 GWh during the first nine months of 2012.

During the first nine months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 9-1). During the first nine months of 2013, the total day-ahead net interchange of -12,727.7 GWh was greater than the net interchange of -5,824.8 GWh during the first nine months of 2012. During the first nine months of 2013, the peak month for net exporting interchange was January, -2,602.8 GWh; in 2012 it was

11 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (Accessed October 10, 2013).

12 See Docket Nos. ER12-1338-000 and ER12-1343-000.

13 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.

January, -1,847.5 GWh. Gross monthly export volumes during the first nine months of 2013 averaged 7,115.8 GWh compared to 16,287.0 GWh for the first nine months of 2012, while gross monthly imports during the first nine months of 2013 averaged 5,701.6 GWh compared to 15,639.8 GWh during the first nine months of 2012.

The large decreases in gross import and export volumes in the Day-Ahead Energy Market were the result of the rule change on November 1, 2012, which permitted up-to congestion transactions to be submitted between two internal buses. Prior to the rule change, up-to congestion transactions were required to have the source at an interface (modeled as an import) or the sink at an interface (modeled as an export).[14]

Figure 9-1 shows the impact of net import and export up-to congestion transactions on the overall net Day-Ahead 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 2013, import up-to congestion transactions accounted for 70.7 percent of all scheduled import MW transactions, export up-to congestion transactions accounted 66.2 percent of all scheduled export MW transactions and net up-to congestion transactions accounted for 48.1 percent of the net interchange volume in the Day-Ahead Market. The average number of import and export up-to congestion bids that had approved MWh in the Day-Ahead Market decreased to 9,741 bids per day, with an average cleared volume of 274,769 MWh per day, in the first nine months of 2013, compared to an average of 22,392 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012.

The average number of up-to congestion bids, including internal up-to congestion transactions, that had approved MWh in the Day-Ahead Market increased to 37,762 bids per day, with an average cleared volume of 1,221,114 MWh per day, in the first nine months of 2013, compared to an average of 22,392 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012.

In the first nine months of 2013, gross imports in the Day-Ahead Energy Market were 150.8 percent of gross imports in the Real-Time Energy Market (403.2 percent during the first nine months of 2012), gross exports in the Day-Ahead Energy Market were 218.5 percent of gross exports in the Real-Time Energy Market (447.5 percent during the first nine months of 2012). In the first nine months of 2013, net interchange was -12,727.7 GWh in the Day-Ahead Energy Market and 4,706.7 GWh in the Real-Time Energy Market compared to -5,824.8 GWh in the Day-Ahead Energy Market and 2,152.5 GWh in the Real-Time Energy Market for the first nine months of 2012.

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.[15] For the first nine months of 2013, 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. In addition, day-ahead transactions can be offset by increment offers, decrement bids and internal bilateral transactions.

14 See *"Up-To Congestion Transaction Enhancements,"* (October 10, 2012) <https://pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-11-up-to-congestion-transactions.ashx> (Accessed October 9, 2013).

15 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, 2013

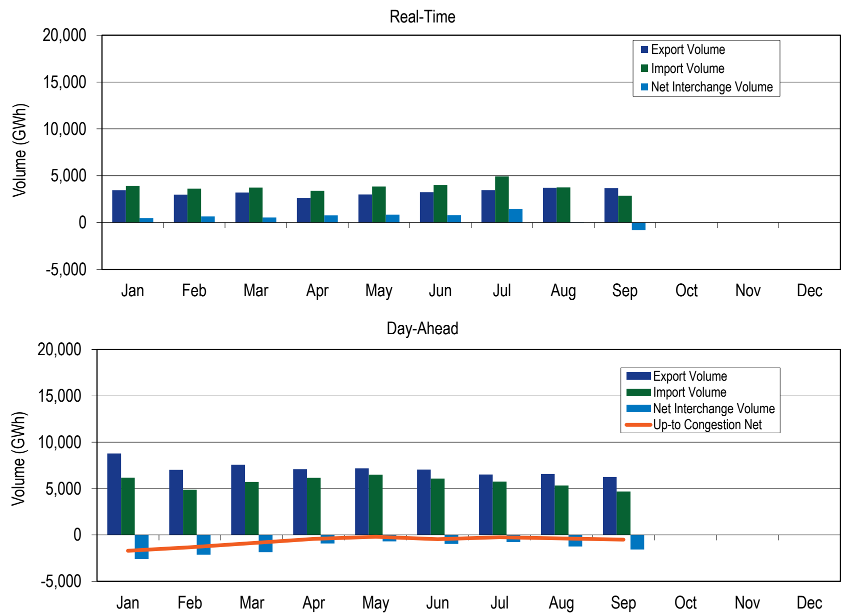
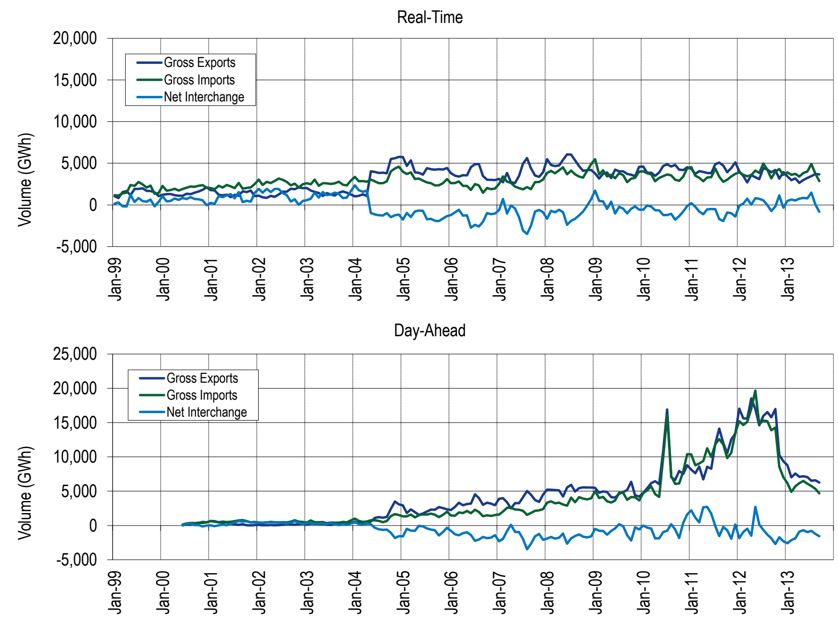


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through September, 2013. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows started 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 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, reducing the day-ahead gross import and export volumes. While the gross import and export volumes in the Day-Ahead 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: January, 1999 through September, 2013



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 2013. Figure 9-3 shows the approximate geographic location of the interfaces. In the first nine months of 2013, PJM had 21 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 balancing authorities. Table 9-1 through Table 9-3 show the Real-Time 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 2013 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, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.[16] The top three net exporting interfaces in the Real-Time Energy Market accounted for 67.3 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 24.2 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 23.6 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 19.5 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 43.9 percent of the total net PJM exports in the Real-Time Energy Market. Nine PJM interfaces had net scheduled imports, with three importing interfaces accounting for 61.2 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 32.6 percent, PJM/Tennessee Valley Authority (TVA) with 16.3 percent and PJM/Michigan Electric Coordinated System (MECS) with 12.3 percent of the net import volume.[17]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of OVEC is owned by load serving entities or their affiliates within the PJM footprint. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires delivery of approximately 70 percent of the generation output into the PJM footprint.[18] OVEC itself does not serve load, and therefore does not generally import energy. OVEC accounts for a large percentage of PJM's net interchange import volume.

16 In June, 2013, the EKPC Interface was eliminated, and the HUDS Interface was added. While there are 21 total interfaces with PJM during 2013, only 20 were active at any given time.

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

Table 9-1 Real-time scheduled net interchange volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(30.6)	(38.3)	(48.4)	(33.1)	(25.3)	188.1	206.8	211.8	(52.7)	378.2
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	175.2	122.7	148.1	80.9	294.6	221.9	263.2	134.0	(49.5)	1,391.1
EKPC	(149.7)	(139.9)	(152.7)	(152.2)	(108.8)					(703.3)
LGEE	281.5	272.0	302.2	182.9	204.3	253.5	312.2	263.2	206.7	2,278.4
MEC	(484.1)	(390.8)	(158.9)	(421.4)	(509.1)	(464.2)	(492.5)	(478.1)	(465.7)	(3,864.8)
MISO	283.1	518.3	572.6	622.4	103.4	62.0	690.9	(318.8)	(442.3)	2,091.8
ALTE	(306.7)	(176.9)	(239.3)	(214.3)	(454.5)	(449.7)	(370.3)	(474.7)	(420.9)	(3,107.5)
ALTW	(9.0)	(4.5)	(3.0)	(3.8)	(25.3)	(40.2)	(1.8)	(33.8)	(17.9)	(139.1)
AMIL	181.7	153.6	181.5	150.2	170.1	12.0	340.6	(76.7)	(145.2)	967.8
CIN	253.3	285.4	349.7	272.0	129.6	350.0	376.1	315.0	165.9	2,496.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(43.4)	48.1	63.8	74.5	(29.2)	128.7	239.6	50.6	(10.8)	522.0
MECS	322.3	298.9	322.5	433.4	529.0	291.8	205.0	24.1	130.0	2,556.8
NIPS	(22.9)	(12.5)	(22.0)	(25.6)	(71.6)	(5.0)	9.3	(7.7)	(6.2)	(164.1)
WEC	(92.1)	(73.8)	(80.5)	(64.0)	(144.7)	(225.6)	(107.6)	(115.6)	(137.1)	(1,041.0)
NYISO	(1,047.1)	(1,018.0)	(1,100.9)	(313.3)	(216.5)	(608.4)	(977.3)	(897.7)	(820.5)	(6,999.7)
HUDS						(24.8)	(31.6)	(17.7)	(7.8)	(81.8)
LIND	(165.2)	(149.8)	(91.6)	(64.9)	(77.0)	(55.8)	(73.0)	(71.9)	(85.2)	(834.7)
NEPT	(270.9)	(245.9)	(239.2)	(247.1)	(102.5)	(167.8)	(409.3)	(415.2)	(223.8)	(2,321.8)
NYIS	(611.0)	(622.3)	(770.1)	(1.3)	(37.0)	(360.0)	(463.3)	(392.9)	(503.7)	(3,761.4)
OVEC	798.2	713.5	585.0	542.8	712.0	908.3	985.5	825.5	685.2	6,756.1
TVA	643.8	600.0	383.6	249.0	392.2	217.6	475.5	297.6	119.5	3,378.9
Total	470.4	639.5	530.6	757.9	846.7	778.9	1,464.4	37.5	(819.3)	4,706.7

18 See *"Ohio Valley Electric Corporation: Company Background,"* <http://www.ovec.com/OVECHistory.pdf> (Accessed October 9, 2013).

Table 9-2 Real-time scheduled gross import volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	1.4	0.1	1.6	0.0	2.0	219.4	236.8	227.4	0.0	688.6
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	225.0	190.6	157.0	137.4	320.4	265.8	301.2	202.6	70.7	1,870.7
EKPC	4.4	1.5	25.6	21.8	33.0					86.3
LGEE	299.0	272.4	302.2	186.0	205.0	255.4	318.3	264.2	223.2	2,325.6
MEC	0.2	48.2	320.6	6.2	0.0	0.0	3.9	3.3	1.1	383.7
MISO	1,026.7	971.1	1,110.5	1,199.0	1,264.4	1,193.4	1,596.0	998.0	896.6	10,255.6
ALTE	0.0	1.1	0.0	0.0	0.0	0.0	3.7	0.0	0.0	4.8
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	207.0	177.1	215.1	198.2	213.8	79.0	386.4	98.4	107.6	1,682.7
CIN	374.5	394.7	455.5	438.9	358.2	519.7	518.4	493.0	361.8	3,914.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	95.9	76.5	101.6	101.3	70.4	176.3	289.3	103.6	62.7	1,077.7
MECS	349.1	321.6	338.3	458.2	621.9	418.4	383.5	302.8	362.5	3,556.4
NIPS	0.2	0.0	0.0	2.4	0.0	0.0	14.7	0.2	1.9	19.3
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	871.0	782.0	820.7	1,037.6	857.5	895.0	984.2	914.4	834.0	7,996.5
HUDS						0.0	0.0	0.0	0.0	0.0
LIND	0.6	10.4	7.5	13.5	7.8	10.2	19.7	9.0	8.1	86.8
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	870.5	771.6	813.2	1,024.1	849.7	884.8	964.5	905.4	825.9	7,909.7
OVEC	798.3	713.5	585.1	543.8	728.4	916.1	985.6	825.5	685.2	6,781.4
TVA	689.8	630.0	399.1	261.5	431.9	265.9	493.8	313.8	146.9	3,632.7
Total	3,915.7	3,609.5	3,722.4	3,393.4	3,842.5	4,010.9	4,919.6	3,749.2	2,857.7	34,021.0

Table 9-3 Real-time scheduled gross export volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	31.9	38.4	50.0	33.1	27.3	31.3	30.0	15.7	52.7	310.3
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	49.8	67.9	8.9	56.5	25.8	43.9	37.9	68.6	120.2	479.5
EKPC	154.0	141.4	178.3	174.0	141.8					789.6
LGEE	17.5	0.4	0.0	3.1	0.7	1.8	6.1	1.1	16.5	47.2
MEC	484.4	439.0	479.6	427.6	509.1	464.2	496.4	481.4	466.8	4,248.5
MISO	743.5	452.8	537.9	576.7	1,161.0	1,131.4	905.0	1,316.7	1,338.8	8,163.8
ALTE	306.7	178.0	239.3	214.3	454.5	449.7	374.0	474.7	420.9	3,112.2
ALTW	9.0	4.5	3.0	3.8	25.3	40.2	1.8	33.8	17.9	139.1
AMIL	25.3	23.5	33.6	48.0	43.7	67.0	45.7	175.2	252.8	714.9
CIN	121.2	109.3	105.8	166.9	228.6	169.7	142.3	178.0	195.9	1,417.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	139.3	28.4	37.8	26.8	99.7	47.6	49.7	53.0	73.5	555.7
MECS	26.8	22.7	15.8	24.8	93.0	126.6	178.6	278.7	232.6	999.5
NIPS	23.0	12.5	22.0	28.0	71.6	5.0	5.4	7.8	8.1	183.4
WEC	92.1	73.8	80.5	64.0	144.7	225.6	107.6	115.6	137.1	1,041.0
NYISO	1,918.1	1,800.1	1,921.6	1,351.0	1,074.0	1,503.4	1,961.4	1,812.1	1,654.6	14,996.2
HUDS						24.8	31.6	17.7	7.8	81.8
LIND	165.8	160.3	99.1	78.5	84.8	66.1	92.7	80.9	93.3	921.5
NEPT	270.9	245.9	239.2	247.1	102.5	167.8	409.3	415.2	223.8	2,321.8
NYIS	1,481.5	1,393.9	1,583.3	1,025.4	886.6	1,244.7	1,427.8	1,298.3	1,329.7	11,671.1
OVEC	0.1	0.0	0.0	1.1	16.4	7.8	0.0	0.0	0.0	25.4
TVA	46.0	30.0	15.6	12.5	39.7	48.3	18.3	16.1	27.4	253.9
Total	3,445.3	2,970.0	3,191.9	2,635.5	2,995.8	3,232.0	3,455.2	3,711.7	3,677.0	29,314.3

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.[19] 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

19 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.[20]

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.[21] 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.[22] 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 for the first nine months of 2013.

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified by PJM only occasionally.

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.[23]

In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at eleven of PJM's 17 interface pricing points eligible for real-time transactions.[24] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 72.6 percent of the total net exports: PJM/MISO with 56.6 percent, and PJM/NYIS with 16.0 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 33.3 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 78.7 percent of the total

20 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.

21 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 9, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

22 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> (Accessed October 9, 2013).

23 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.

24 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

net imports: PJM/SouthIMP with 49.9 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 28.8 percent of the net import volume.

Table 9-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS						(24.8)	(31.6)	(17.7)	(7.8)	(81.8)
IMO	592.6	395.0	556.4	547.2	668.7	584.3	616.2	516.6	522.7	4,999.6
LINDENVFT	(165.2)	(149.8)	(91.6)	(64.9)	(77.0)	(55.8)	(73.0)	(71.9)	(85.2)	(834.7)
MISO	(1,015.3)	(686.3)	(699.3)	(709.9)	(1,444.8)	(1,513.8)	(1,146.5)	(1,683.6)	(1,675.8)	(10,575.4)
NEPTUNE	(270.9)	(245.9)	(239.2)	(247.1)	(102.5)	(167.8)	(409.3)	(415.2)	(223.8)	(2,321.8)
NORTHWEST	(3.6)	(3.3)	(5.9)	(5.0)	(5.5)	(2.7)	(1.2)	(0.3)	(3.9)	(31.5)
NYIS	(603.2)	(572.1)	(706.3)	62.9	28.4	(230.2)	(289.9)	(271.6)	(402.6)	(2,984.7)
OVEC	798.2	713.5	585.0	542.8	712.0	908.3	985.5	825.5	685.2	6,756.1
SOUTHIMP	1,441.6	1,472.4	1,387.4	923.1	1,306.5	1,411.2	1,909.4	1,260.0	591.9	11,703.4
CPLEIMP	0.0	0.0	0.0	0.0	0.0	219.4	230.0	222.8	0.0	672.2
DUKIMP	107.2	105.3	83.8	46.7	110.6	129.7	136.7	58.7	28.4	807.1
NCMPAIMP	68.6	31.3	19.5	22.6	95.1	61.7	62.1	48.5	17.6	427.1
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	853.8	1,100.9	1,000.4	1,480.5	930.0	545.9	9,797.0
SOUTHEXP	(303.9)	(283.9)	(255.9)	(291.0)	(238.9)	(129.7)	(95.1)	(104.2)	(220.0)	(1,922.6)
CPLEEXP	(31.3)	(33.4)	(47.6)	(32.0)	(26.7)	(30.8)	(29.7)	(15.2)	(49.7)	(296.4)
DUKEXP	(27.1)	(45.2)	(0.9)	(32.9)	(11.8)	(29.9)	(27.3)	(44.4)	(45.3)	(264.8)
NCMPAEXP	0.0	(0.1)	0.0	(0.2)	0.0	(1.5)	0.0	0.0	0.0	(1.7)
SOUTHWEST	(4.5)	(5.7)	(3.0)	(11.7)	(3.6)	(4.4)	(2.4)	(2.3)	(2.8)	(40.3)
SOUTHEXP	(241.0)	(199.6)	(204.5)	(214.2)	(196.9)	(63.1)	(35.6)	(42.3)	(122.2)	(1,319.5)
Total	470.4	639.5	530.6	757.9	846.7	778.9	1,464.4	37.5	(819.3)	4,706.7

Table 9-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS						0.0	0.0	0.0	0.0	0.0
IMO	594.6	403.2	562.5	549.8	669.9	584.7	621.6	522.0	533.1	5,041.3
LINDENVFT	0.6	10.4	7.5	13.5	7.8	10.2	19.7	9.0	8.1	86.8
MISO	204.4	196.3	309.1	277.5	215.9	74.6	250.9	110.3	116.3	1,755.4
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	0.7	0.0	0.7
NYIS	876.3	813.6	870.9	1,085.7	914.0	1,014.1	1,132.5	1,021.6	923.1	8,651.9
OVEC	798.3	713.5	585.1	543.8	728.4	916.1	985.6	825.5	685.2	6,781.4
SOUTHIMP	1,441.6	1,472.4	1,387.4	923.1	1,306.5	1,411.2	1,909.4	1,260.0	591.9	11,703.4
CPLEIMP	0.0	0.0	0.0	0.0	0.0	219.4	230.0	222.8	0.0	672.2
DUKIMP	107.2	105.3	83.8	46.7	110.6	129.7	136.7	58.7	28.4	807.1
NCMPAIMP	68.6	31.3	19.5	22.6	95.1	61.7	62.1	48.5	17.6	427.1
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	853.8	1,100.9	1,000.4	1,480.5	930.0	545.9	9,797.0
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
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	3,915.7	3,609.5	3,722.4	3,393.4	3,842.5	4,010.9	4,919.6	3,749.2	2,857.7	34,021.0

Table 9-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS						24.8	31.6	17.7	7.8	81.8
IMO	2.0	8.2	6.1	2.6	1.3	0.4	5.3	5.4	10.3	41.7
LINDENVFT	165.8	160.3	99.1	78.5	84.8	66.1	92.7	80.9	93.3	921.5
MISO	1,219.7	882.6	1,008.4	987.4	1,660.7	1,588.4	1,397.5	1,794.0	1,792.1	12,330.8
NEPTUNE	270.9	245.9	239.2	247.1	102.5	167.8	409.3	415.2	223.8	2,321.8
NORTHWEST	3.6	3.3	5.9	5.0	5.5	2.7	1.2	1.0	3.9	32.2
NYIS	1,479.5	1,385.8	1,577.2	1,022.8	885.6	1,244.3	1,422.4	1,293.2	1,325.7	11,636.6
OVEC	0.1	0.0	0.0	1.1	16.4	7.8	0.0	0.0	0.0	25.4
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
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	303.9	283.9	255.9	291.0	238.9	129.7	95.1	104.2	220.0	1,922.6
CPLEEXP	31.3	33.4	47.6	32.0	26.7	30.8	29.7	15.2	49.7	296.4
DUKEXP	27.1	45.2	0.9	32.9	11.8	29.9	27.3	44.4	45.3	264.8
NCMPAEXP	0.0	0.1	0.0	0.2	0.0	1.5	0.0	0.0	0.0	1.7
SOUTHWEST	4.5	5.7	3.0	11.7	3.6	4.4	2.4	2.3	2.8	40.3
SOUTHEXP	241.0	199.6	204.5	214.2	196.9	63.1	35.6	42.3	122.2	1,319.5
Total	3,445.3	2,970.0	3,191.9	2,635.5	2,995.8	3,232.0	3,455.2	3,711.7	3,677.0	29,314.3

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 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.[25] 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,

25 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.

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.[26]

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 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 Market is shown by interface for the first nine months of 2013 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, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.[27] The top three net exporting interfaces in the Real-Time Energy Market accounted for 77.6 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 30.7 percent, PJM/MidAmerican Energy Company (MEC) with 29.6 percent, and PJM/NEPT with 17.2 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 48.9 percent of the total net PJM exports in the Day-Ahead Energy Market. The nine separate interfaces that connect PJM to MISO together represented 14.1 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interfaces had net scheduled imports, with three importing interfaces accounting for 79.8 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 63.1 percent, PJM/DUK with 11.1 percent and PJM/Michigan Electric Coordinated Systems (MECS) with 5.7 percent of the net import volume.[28]

26 See the *2010 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for details.
27 In June, 2013, the EKPC Interface was eliminated, and the HUDS Interface was added. While there are 21 total interfaces with PJM during 2013, only 20 were active at any given time.
28 In the Day-Ahead Market, two PJM interfaces had a net interchange of zero (PJM/Carolina Power and Light – Western (CPLW) and PJM/City Water Light & Power (CWLP)).

Table 9-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(33.4)	(28.5)	(41.2)	(30.5)	(24.1)	172.0	208.7	215.4	(47.1)	391.2
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	82.3	145.7	127.5	149.9	80.9	22.3	832.6
EKPC	(36.6)	(33.6)	(37.2)	(36.0)	(37.2)					(180.5)
LGEE	58.3	65.8	81.8	40.3	2.3	0.0	0.0	0.0	0.0	248.5
MEC	(483.0)	(435.7)	(477.7)	(423.0)	(484.7)	(462.9)	(463.0)	(472.9)	(454.9)	(4,157.8)
MISO	(242.1)	(52.6)	(48.7)	(34.3)	(324.7)	(302.2)	(204.9)	(419.6)	(343.7)	(1,972.8)
ALTE	(177.8)	(79.5)	(119.1)	(99.9)	(238.2)	(267.3)	(289.0)	(318.5)	(296.3)	(1,885.4)
ALTW	(7.6)	(2.5)	0.0	0.0	(2.5)	(35.8)	0.0	(24.0)	(6.8)	(79.1)
AMIL	8.7	5.2	26.3	13.5	(0.9)	(1.2)	1.9	(5.0)	(38.2)	10.3
CIN	7.9	45.9	37.1	32.3	18.3	44.4	41.6	37.1	61.9	326.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(0.9)	(5.9)	(1.6)	0.0	0.0	33.9	117.5	54.5	0.0	197.6
MECS	23.4	45.8	102.9	93.1	97.9	36.9	8.9	(55.8)	72.2	425.4
NIPS	(22.2)	(12.5)	(21.5)	(27.8)	(70.7)	0.0	0.6	0.0	(0.2)	(154.3)
WEC	(73.7)	(49.2)	(72.8)	(45.5)	(128.8)	(113.1)	(86.4)	(107.9)	(136.4)	(813.8)
NYISO	(833.6)	(874.4)	(944.3)	(459.5)	(386.6)	(707.5)	(968.7)	(910.2)	(777.0)	(6,861.8)
HUDS					(32.5)	(36.6)	(18.4)	(12.1)	(7.9)	(107.6)
LIND	(15.3)	(14.3)	(2.6)	0.1	0.0	0.1	0.0	0.0	0.0	(32.1)
NEPT	(278.5)	(255.2)	(248.7)	(253.1)	(101.5)	(193.7)	(420.0)	(425.6)	(236.7)	(2,413.1)
NYIS	(539.7)	(604.9)	(693.0)	(206.5)	(252.6)	(477.2)	(530.3)	(472.4)	(532.3)	(4,309.1)
OVEC	561.5	494.4	408.0	324.6	522.8	644.8	691.9	598.5	498.0	4,744.4
TVA	32.7	3.6	(3.6)	41.2	92.4	18.6	71.9	47.0	42.9	346.7
Total without Up-To Congestion	(898.1)	(790.9)	(987.2)	(494.9)	(494.1)	(509.7)	(514.3)	(860.9)	(1,059.5)	(6,609.5)
Up-To Congestion	(1,704.8)	(1,336.7)	(875.0)	(421.3)	(191.6)	(457.4)	(252.3)	(374.2)	(505.0)	(6,118.1)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(916.1)	(685.7)	(967.1)	(766.5)	(1,235.0)	(1,564.5)	(12,727.7)

Table 9-8 Day-Ahead scheduled gross import volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	0.0	0.0	0.0	0.0	0.0	202.5	237.7	228.5	0.0	668.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	82.3	145.7	127.5	149.9	80.9	24.2	834.6
EKPC	0.0	0.0	0.0	0.0	0.0					0.0
LGEE	58.3	65.8	81.8	40.3	2.3	0.0	0.0	0.0	0.0	248.5
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	75.2	115.2	196.6	184.4	231.6	229.4	270.8	213.2	235.3	1,751.8
ALTE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	8.7	5.2	26.3	13.5	3.9	1.9	1.9	0.0	7.9	69.5
CIN	21.5	64.2	58.4	77.7	61.9	52.0	41.6	41.5	62.7	481.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	5.6	0.0	0.0	0.0	0.0	33.9	117.5	54.5	0.0	211.6
MECS	39.3	45.8	111.9	93.1	165.8	141.6	109.2	117.1	164.6	988.6
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.6
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	726.2	650.4	717.7	768.3	601.6	726.7	755.8	749.1	696.8	6,392.6
HUDS					0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.1	9.3	2.9	0.1	0.0	0.1	0.0	0.0	0.0	12.4
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	726.2	641.1	714.8	768.2	601.6	726.6	755.8	749.1	696.8	6,380.2
OVEC	561.5	494.4	408.0	324.6	522.8	644.8	691.9	598.5	498.0	4,744.4
TVA	41.7	13.6	3.6	42.7	102.8	21.5	74.1	47.0	50.1	397.0
Total without Up-To Congestion	1,540.9	1,409.5	1,483.5	1,442.6	1,606.8	1,952.4	2,180.1	1,917.2	1,504.4	15,037.5
Up-To Congestion	4,637.9	3,481.0	4,226.5	4,728.9	4,890.0	4,135.3	3,571.1	3,422.3	3,183.9	36,276.8
Total	6,178.8	4,890.5	5,710.0	6,171.5	6,496.8	6,087.8	5,751.2	5,339.5	4,688.3	51,314.3

Table 9-9 Day-Ahead scheduled gross export volume by interface (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	33.4	28.5	41.2	30.5	24.1	30.5	29.0	13.1	47.1	277.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0
EKPC	36.6	33.6	37.2	36.0	37.2					180.5
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	483.0	435.7	477.7	423.0	484.7	462.9	463.0	472.9	454.9	4,157.8
MISO	317.3	167.9	245.4	218.6	556.4	531.6	475.7	632.8	579.0	3,724.6
ALTE	177.8	79.5	119.1	99.9	238.2	267.3	289.0	318.5	296.3	1,885.4
ALTW	7.6	2.5	0.0	0.0	2.5	35.8	0.0	24.0	6.8	79.1
AMIL	0.0	0.0	0.0	0.0	4.8	3.2	0.0	5.0	46.1	59.2
CIN	13.7	18.3	21.3	45.5	43.5	7.6	0.0	4.4	0.8	155.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	6.5	5.9	1.6	0.0	0.0	0.0	0.0	0.0	0.0	14.0
MECS	15.9	0.0	9.1	0.0	67.9	104.7	100.3	172.9	92.5	563.2
NIPS	22.2	12.5	21.5	27.8	70.7	0.0	0.0	0.0	0.2	154.9
WEC	73.7	49.2	72.8	45.5	128.8	113.1	86.4	107.9	136.4	813.8
NYISO	1,559.8	1,524.8	1,662.1	1,227.8	988.2	1,434.2	1,724.5	1,659.3	1,473.8	13,254.4
HUDS					32.5	36.6	18.4	12.1	7.9	107.6
LIND	15.4	23.6	5.5	0.0	0.0	0.0	0.0	0.0	0.0	44.5
NEPT	278.5	255.2	248.7	253.1	101.5	193.7	420.0	425.6	236.7	2,413.1
NYIS	1,265.9	1,246.0	1,407.8	974.7	854.2	1,203.9	1,286.1	1,221.6	1,229.1	10,689.2
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	9.0	10.0	7.2	1.5	10.4	2.9	2.2	0.0	7.1	50.3
Total without Up-To Congestion	2,439.0	2,200.5	2,470.7	1,937.5	2,100.9	2,462.2	2,694.4	2,778.1	2,563.9	21,647.0
Up-To Congestion	6,342.6	4,817.7	5,101.5	5,150.2	5,081.6	4,592.7	3,823.4	3,796.4	3,688.9	42,395.0
Total	8,781.6	7,018.2	7,572.2	7,087.7	7,182.4	7,054.9	6,517.8	6,574.5	6,252.8	64,042.0

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-10 through Table 9-15 show the Day-Ahead Market interchange totals at the individual interface pricing points. In the first nine months of 2013, up-to congestion transactions accounted for 70.7 percent of all scheduled import MW transactions, 66.2 percent of all scheduled export MW transactions and 48.1 percent of the net interchange volume in the Day-Ahead Market. Net interchange in the Day-Ahead Market, including up-to congestion transactions, is shown by interface pricing point for the first nine months of 2013 in Table 9-10. Up-to congestion transactions by interface pricing point for the first nine months of 2013 are shown in Table 9-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead 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 are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast). The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the integration, 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.[29] After

29 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (Accessed October 10, 2013).

the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. 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 no longer accept long term positions of any kind at the NIPSCO and Southeast interface pricing points and to eliminate these interface pricing points from the Day-Ahead and Real-Time Energy Markets.

In the Day-Ahead Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 57.7 percent of the total net exports: PJM/SouthEXP with 23.3 percent, PJM/NIPSCO with 17.9 percent and PJM/Neptune with 16.6 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 31.0 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 77.7 percent of the total net imports: PJM/SouthIMP with 36.8 percent, PJM/Southeast with 21.6 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 19.3 percent of the net import volume.[30]

In the Day-Ahead Market, for the first nine months of 2013, up-to congestion transactions had net exports at seven 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 74.2 percent of the total net up-to congestion exports: PJM/SouthEXP with 29.2 percent, PJM/NIPSCO with 23.5 percent and PJM/Southwest with 21.5 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 7.8 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 7.4 percent and PJM/LIND with 0.4 percent). The PJM/NYIS and the PJM/HUDS interface pricing points had net imports in the Day-Ahead Energy Market. Six PJM interface pricing points had net up-to congestion imports, with three importing interface pricing points accounting for 71.6 percent of the total net up-to congestion imports: PJM/MISO with 30.8 percent, PJM/Northwest with 21.9 percent and PJM/Southeast with 18.9 percent of the net import volume.[31]

30 In the Day-Ahead Market, one PJM interface pricing points had a net interchange of zero (PJM/DUKEXP).

Table 9-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					(32.5)	(36.6)	116.2	(49.5)	64.8	62.4
IMO	27.4	235.1	206.5	104.5	100.1	37.8	42.5	27.4	87.8	869.0
LINDENVFT	102.2	14.5	(14.6)	(16.8)	(68.7)	(13.6)	33.3	(95.6)	(48.1)	(107.5)
MISO	192.7	130.5	453.0	228.8	(434.9)	(207.4)	(305.0)	(174.3)	(265.1)	(381.5)
NEPTUNE	(335.1)	(381.7)	(398.9)	(473.6)	(341.6)	(302.0)	(541.9)	(541.5)	(338.8)	(3,655.1)
NIPSCO	(927.2)	(757.5)	(743.5)	(591.9)	(121.5)	(269.9)	(221.9)	(145.1)	(166.9)	(3,945.5)
NORTHWEST	(744.5)	(810.7)	(646.6)	199.5	520.7	128.3	(9.0)	(176.0)	(309.3)	(1,847.5)
NYIS	(662.2)	(576.6)	(506.4)	208.5	10.8	(312.0)	(346.8)	(432.6)	(465.7)	(3,083.0)
OVEC	254.6	210.5	438.4	269.4	92.5	142.3	247.3	69.1	64.0	1,788.1
SOUTHIMP	1,255.6	902.5	877.1	965.4	1,108.3	1,236.1	1,547.2	1,389.6	886.3	10,168.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	202.5	231.5	227.2	0.0	661.2
DUKIMP	22.5	22.0	9.0	7.0	17.5	46.8	63.1	17.0	2.0	207.0
NCMPAIMP	18.3	15.4	14.9	19.1	84.6	53.9	62.1	42.4	16.8	327.4
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	182.9	446.4	340.8	257.3	2,866.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	2,693.8
SOUTHIMP	442.8	307.4	302.0	349.9	423.2	373.5	496.7	394.3	322.8	3,412.6
SOUTHEXP	(1,766.4)	(1,094.4)	(1,527.3)	(1,809.8)	(1,518.9)	(1,370.0)	(1,328.6)	(1,106.6)	(1,073.4)	(12,595.4)
CPLEEXP	(32.4)	(27.8)	(40.7)	(29.6)	(22.8)	(29.5)	(27.4)	(12.7)	(46.8)	(269.5)
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	(1.0)	(0.8)	(0.5)	(0.9)	(1.3)	(1.1)	(1.6)	(0.5)	(0.4)	(8.0)
SOUTHEAST	(49.3)	(28.8)	(26.5)	(123.4)	(213.1)	(118.9)	(190.9)	(59.8)	(50.3)	(861.0)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(1,017.5)	(653.5)	(638.6)	(480.0)	(605.4)	(675.2)	(6,317.8)
SOUTHEXP	(771.5)	(501.6)	(659.5)	(638.4)	(628.2)	(582.0)	(628.8)	(428.3)	(300.8)	(5,139.0)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(916.1)	(685.7)	(967.1)	(766.5)	(1,235.0)	(1,564.5)	(12,727.7)

31 In the Day-Ahead 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, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					0.0	0.0	134.7	(37.4)	72.7	170.0
IMO	(11.9)	189.4	94.5	18.0	(62.6)	(92.8)	(55.8)	(79.2)	(76.9)	(77.3)
LINDENVFT	117.5	28.8	(12.0)	(16.9)	(68.7)	(13.7)	33.3	(95.6)	(48.1)	(75.4)
MISO	500.7	288.8	660.8	422.2	117.7	323.4	164.1	458.2	305.6	3,241.5
NEPTUNE	(56.5)	(126.5)	(150.2)	(220.6)	(240.1)	(108.3)	(121.9)	(115.9)	(102.1)	(1,242.0)
NIPSCO	(927.2)	(757.5)	(743.5)	(591.9)	(121.5)	(269.9)	(221.9)	(145.1)	(166.9)	(3,945.5)
NORTHWEST	(261.6)	(375.0)	(168.9)	622.5	1,004.7	591.2	454.0	296.9	145.6	2,309.5
NYIS	(121.9)	25.3	185.7	415.0	264.0	165.2	183.5	40.1	65.1	1,222.1
OVEC	(306.9)	(281.8)	31.4	(55.2)	(430.3)	(502.5)	(444.6)	(529.4)	(432.1)	(2,951.4)
SOUTHIMP	1,050.5	694.0	668.9	727.3	792.5	786.7	919.7	926.7	749.3	7,315.5
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	488.4	326.9	366.3	268.4	188.8	181.0	440.7	338.9	256.8	2,856.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	2,693.8
SOUTHIMP	278.5	136.1	117.7	137.9	209.4	229.0	231.7	219.9	205.1	1,765.4
SOUTHEXP	(1,687.4)	(1,022.2)	(1,441.8)	(1,741.8)	(1,447.2)	(1,336.7)	(1,297.4)	(1,093.5)	(1,017.1)	(12,085.1)
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	(49.3)	(28.8)	(26.5)	(123.4)	(213.1)	(118.9)	(190.9)	(59.8)	(50.3)	(861.0)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(1,017.5)	(653.5)	(638.6)	(480.0)	(605.4)	(675.2)	(6,317.8)
SOUTHEXP	(725.9)	(457.9)	(615.1)	(600.9)	(580.6)	(579.2)	(626.6)	(428.3)	(291.6)	(4,906.3)
Total Interfaces	(1,704.8)	(1,336.7)	(875.0)	(421.3)	(191.6)	(457.4)	(252.3)	(374.2)	(505.0)	(6,118.1)
INTERNAL	22,906.0	23,311.1	27,439.6	32,152.2	34,779.0	34,935.1	29,883.4	29,207.9	26,044.7	260,659.1
Total	21,201.2	21,974.3	26,564.6	31,731.0	34,587.4	34,477.8	29,496.5	28,871.1	25,467.1	254,371.0

Table 9-12 Day-Ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					0.0	0.0	159.7	32.4	116.9	309.0
IMO	268.0	322.5	310.8	285.5	376.4	341.5	316.0	290.3	375.6	2,886.8
LINDENVFT	292.4	210.2	188.5	130.0	145.1	119.8	143.7	37.3	40.2	1,307.1
MISO	719.6	516.2	809.8	770.8	470.0	591.0	429.1	624.6	438.5	5,369.5
NEPTUNE	127.2	32.2	11.5	17.2	10.8	10.1	27.4	6.7	1.7	244.8
NIPSCO	35.0	17.1	15.0	65.2	180.8	135.0	136.6	120.4	60.6	766.0
NORTHWEST	287.9	214.8	229.9	818.0	1,184.5	728.3	561.9	507.2	337.1	4,869.4
NYIS	1,097.0	1,031.5	1,130.2	1,260.6	991.5	1,046.5	1,103.7	966.1	898.1	9,525.2
OVEC	2,096.0	1,643.5	2,137.2	1,858.8	2,029.3	1,879.4	1,325.7	1,364.9	1,533.3	15,868.3
SOUTHIMP	1,255.6	902.5	877.1	965.4	1,108.3	1,236.1	1,547.2	1,389.6	886.3	10,168.3
CPLEIMP	0.0	0.0	0.0	0.0	0.0	202.5	231.5	227.2	0.0	661.2
DUKIMP	22.5	22.0	9.0	7.0	17.5	46.8	63.1	17.0	2.0	207.0
NCMPAIMP	18.3	15.4	14.9	19.1	84.6	53.9	62.1	42.4	16.8	327.4
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	182.9	446.4	340.8	257.3	2,866.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	2,693.8
SOUTHIMP	442.8	307.4	302.0	349.9	423.2	373.5	496.7	394.3	322.8	3,412.6
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	6,178.8	4,890.5	5,710.0	6,171.5	6,496.8	6,087.8	5,751.2	5,339.5	4,688.3	51,314.3

Table 9-13 Up-to Congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					0.0	0.0	159.7	32.4	116.9	309.0
IMO	228.7	276.6	198.9	199.1	213.8	210.9	217.7	183.7	211.0	1,940.4
LINDENVFT	292.4	200.9	185.5	129.9	145.1	119.8	143.7	37.3	40.2	1,294.7
MISO	710.9	505.8	772.2	745.5	466.1	590.2	422.5	624.3	430.5	5,267.9
NEPTUNE	127.2	32.2	11.5	17.2	10.8	10.1	27.4	6.7	1.7	244.8
NIPSCO	35.0	17.1	15.0	65.2	180.8	135.0	136.6	120.4	60.6	766.0
NORTHWEST	287.9	214.8	229.9	818.0	1,184.5	728.3	561.9	507.2	337.1	4,869.4
NYIS	370.9	388.3	414.4	492.4	389.9	319.8	347.9	217.3	199.5	3,140.3
OVEC	1,534.5	1,151.2	1,730.2	1,534.2	1,506.5	1,234.6	633.9	766.4	1,037.2	11,128.8
SOUTHIMP	1,050.5	694.0	668.9	727.3	792.5	786.7	919.7	926.7	749.3	7,315.5
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	488.4	326.9	366.3	268.4	188.8	181.0	440.7	338.9	256.8	2,856.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	2,693.8
SOUTHIMP	278.5	136.1	117.7	137.9	209.4	229.0	231.7	219.9	205.1	1,765.4
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	4,637.9	3,481.0	4,226.5	4,728.9	4,890.0	4,135.3	3,571.1	3,422.3	3,183.9	36,276.8

Table 9-14 Day-Ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					32.5	36.6	43.4	81.9	52.1	246.6
IMO	240.6	87.4	104.4	181.1	276.4	303.7	273.5	262.9	287.9	2,017.8
LINDENVFT	190.2	195.7	203.1	146.7	213.8	133.4	110.4	132.9	88.3	1,414.6
MISO	526.9	385.6	356.8	541.9	904.9	798.4	734.1	798.8	703.5	5,751.0
NEPTUNE	462.2	413.9	410.4	490.9	352.4	312.1	569.3	548.2	340.5	3,899.9
NIPSCO	962.3	774.6	758.5	657.2	302.4	405.0	358.5	265.5	227.6	4,711.4
NORTHWEST	1,032.4	1,025.5	876.4	618.5	663.8	600.0	570.8	683.1	646.4	6,716.9
NYIS	1,759.2	1,608.1	1,636.5	1,052.1	980.7	1,358.5	1,450.5	1,398.7	1,363.8	12,608.1
OVEC	1,841.4	1,433.0	1,698.8	1,589.5	1,936.8	1,737.2	1,078.5	1,295.8	1,469.3	14,080.2
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	1,766.4	1,094.4	1,527.3	1,809.8	1,518.9	1,370.0	1,328.6	1,106.6	1,073.4	12,595.4
CPLEEXP	32.4	27.8	40.7	29.6	22.8	29.5	27.4	12.7	46.8	269.5
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	1.0	0.8	0.5	0.9	1.3	1.1	1.6	0.5	0.4	8.0
SOUTHEAST	49.3	28.8	26.5	123.4	213.1	118.9	190.9	59.8	50.3	861.0
SOUTHWEST	912.1	535.5	800.2	1,017.5	653.5	638.6	480.0	605.4	675.2	6,317.8
SOUTHEXP	771.5	501.6	659.5	638.4	628.2	582.0	628.8	428.3	300.8	5,139.0
Total	8,781.6	7,018.2	7,572.2	7,087.7	7,182.4	7,054.9	6,517.8	6,574.5	6,252.8	64,042.0

Table 9-15 Up-to Congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS					0.0	0.0	25.0	69.8	44.2	139.0
IMO	240.6	87.3	104.4	181.1	276.4	303.7	273.5	262.9	287.9	2,017.7
LINDENVFT	174.8	172.1	197.6	146.7	213.8	133.4	110.4	132.9	88.3	1,370.1
MISO	210.2	217.0	111.4	323.3	348.4	266.7	258.4	166.1	124.9	2,026.4
NEPTUNE	183.7	158.7	161.7	237.8	250.9	118.4	149.3	122.6	103.8	1,486.8
NIPSCO	962.3	774.6	758.5	657.2	302.4	405.0	358.5	265.5	227.6	4,711.4
NORTHWEST	549.4	589.8	398.7	195.5	179.8	137.1	107.8	210.2	191.6	2,559.9
NYIS	492.8	362.9	228.7	77.4	126.0	154.6	164.4	177.1	134.3	1,918.3
OVEC	1,841.4	1,433.0	1,698.8	1,589.5	1,936.8	1,737.2	1,078.5	1,295.8	1,469.3	14,080.2
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	1,687.4	1,022.2	1,441.8	1,741.8	1,447.2	1,336.7	1,297.4	1,093.5	1,017.1	12,085.1
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	49.3	28.8	26.5	123.4	213.1	118.9	190.9	59.8	50.3	861.0
SOUTHWEST	912.1	535.5	800.2	1,017.5	653.5	638.6	480.0	605.4	675.2	6,317.8
SOUTHEXP	725.9	457.9	615.1	600.9	580.6	579.2	626.6	428.3	291.6	4,906.3
Total	6,342.6	4,817.7	5,101.5	5,150.2	5,081.6	4,592.7	3,823.4	3,796.4	3,688.9	42,395.0

Table 9-16 Active interfaces: January through September, 2013[32,33,34]

	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	
EKPC	Active	Active	Active	Active	Active				
HUDS						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

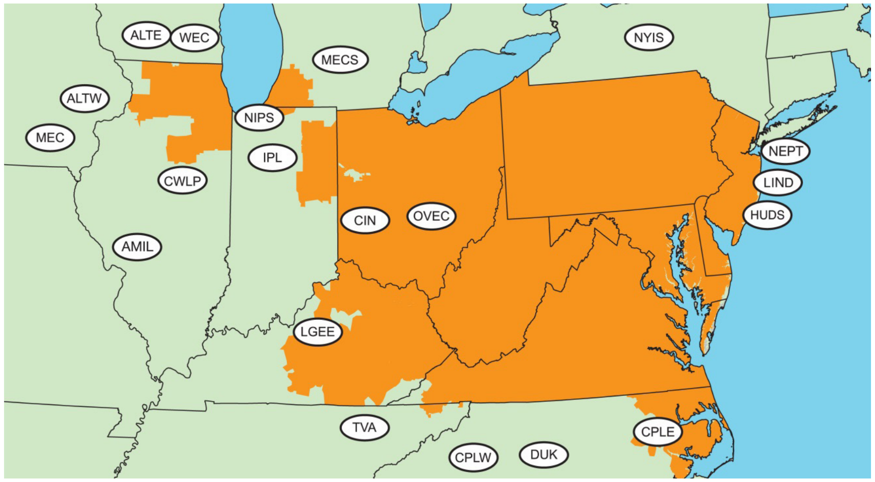


Table 9-17 Active pricing points: January through September, 2013[35]

	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
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	

32 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of June 30, 2013, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.
33 On June 1, 2013, East Kentucky Power Cooperative (EKPC) integrated with PJM, resulting in the elimination of the EKPC Interface.
34 On June 3, 2013, the Hudson DC Line began commercial operation resulting in the addition of the HUDS Interface.

35 On June 3, 2013, the Hudson DC Line began commercial operation resulting in the addition of the HUDSONTP Interface Pricing Point.

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.[36]

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. For the first nine months of 2012, net scheduled interchange was 1,051 GWh and net actual interchange was 801 GWh, a difference of 251 GWh.[37] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[38]

Table 9-18 Net scheduled and actual PJM flows by interface (GWh): January through September, 2013

	Actual	Net Scheduled	Difference (GWh)
CPLE	5,666	281	5,385
CPLW	(1,103)	0	(1,103)
DUK	481	1,391	(910)
EKPC	957	(569)	1,526
LGEE	1,361	2,278	(917)
MEC	(1,695)	(3,859)	2,164
MISO	(9,203)	1,804	(11,007)
ALTE	(4,604)	(3,107)	(1,497)
ALTW	(1,731)	(139)	(1,592)
AMIL	8,443	968	7,475
CIN	(3,931)	2,301	(6,231)
CWLP	(289)	0	(289)
IPL	365	431	(66)
MECS	(8,681)	2,557	(11,238)
NIPS	(3,309)	(164)	(3,145)
WEC	4,534	(1,041)	5,575
NYISO	(7,093)	(7,142)	48
HUDS	(82)	(82)	0
LIND	(835)	(835)	0
NEPT	(2,322)	(2,322)	0
NYIS	(3,855)	(3,903)	48
OVEC	9,771	6,756	3,015
TVA	4,331	2,374	1,957
Total	3,474	3,316	158

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.[39] 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.

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

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

37 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.

38 See PJM. "M-12: Balancing Operations", Revision 29 (November 1, 2013).

39 The terms balancing authority and control area are used interchangeably in this section. The NERC tag applications maintained the terminology of GCA and 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.)

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 (10,737 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 8,769 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, 2013

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(82)	(82)	0
IMO	0	5,000	(5,000)
LINDENVFT	(835)	(835)	0
MISO	(8,246)	(10,729)	2,483
NEPTUNE	(2,322)	(2,322)	0
NORTHWEST	(1,695)	(25)	(1,670)
NYIS	(3,855)	(3,127)	(728)
OVEC	9,771	6,756	3,015
SOUTHIMP	10,737	10,602	135
CPLEIMP	0	672	(672)
DUKIMP	0	807	(807)
NCMPAIMP	0	427	(427)
SOUTHWEST	0	0	0
SOUTHIMP	10,737	8,695	2,041
SOUTHEXP	0	(1,923)	1,923
CPLEEXP	0	(296)	296
DUKEXP	0	(265)	265
NCMPAEXP	0	(2)	2
SOUTHWEST	0	(41)	41
SOUTHEXP	0	(1,319)	1,319
Total	3,474	3,316	158

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, 2013

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(82)	(82)	0
LINDENVFT	(835)	(835)	0
MISO	(8,246)	(5,706)	(2,540)
NEPTUNE	(2,322)	(2,322)	0
NORTHWEST	(1,695)	(25)	(1,670)
NYIS	(3,855)	(3,150)	(705)
OVEC	9,771	6,756	3,015
SOUTHIMP	10,737	10,602	135
CPLEIMP	0	672	(672)
DUKIMP	0	807	(807)
NCMPAIMP	0	427	(427)
SOUTHWEST	0	0	0
SOUTHIMP	10,737	8,695	2,041
SOUTHEXP	0	(1,923)	1,923
CPLEEXP	0	(296)	296
DUKEXP	0	(265)	265
NCMPAEXP	0	(2)	2
SOUTHWEST	0	(41)	41
SOUTHEXP	0	(1,319)	1,319
Total	3,474	3,316	158

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.

The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, PJM should, recognizing that transactions sourcing in SPP and sinking in PJM will create flows across the southern border, require that market participants submit the transaction to enter the PJM footprint across a neighboring balancing authority that is mapped to the SouthIMP Interface price. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely to the expected actual power flows as possible would result in a more economic dispatch of the entire Eastern Interconnection.

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 for the first nine months of 2013, 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 of the Ontario Independent Electricity System Operator (IMO), and thus actual flows were assigned the IMO Interface Pricing point (1,569 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 (1,368 GWh).

Table 9-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through September, 2013

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(4,604)	(3,107)	(1,497)	IPL		365	431	(66)
	MISO	(4,604)	(3,107)	(1,497)		IMO	0	653	(653)
	NORTHWEST	0	(1)	1		MISO	365	(595)	960
	SOUTHIMP	0	1	(1)		SOUTHEXP	0	(2)	2
ALTW		(1,731)	(139)	(1,592)		SOUTHIMP	0	374	(374)
	MISO	(1,731)	(139)	(1,592)	LGEE		1,361	2,278	(917)
AMIL		8,443	968	7,475		SOUTHEXP	0	(47)	47
	MISO	8,443	730	7,713		SOUTHIMP	1,361	2,326	(964)
	NORTHWEST	0	(1)	1	LIND		(835)	(835)	0
	SOUTHIMP	0	279	(279)		LINDENVFT	(835)	(835)	0
	SOUTHWEST	0	(41)	41	MEC		(1,695)	(3,859)	2,164
CIN		(3,931)	2,301	(6,231)		MISO	0	(4,211)	4,211
	IMO	0	1,569	(1,569)		NORTHWEST	(1,695)	6	(1,701)
	MISO	(3,931)	(1,368)	(2,562)		SOUTHIMP	0	346	(346)
	NORTHWEST	0	(28)	28	MECS		(8,681)	2,557	(11,238)
	NYIS	0	753	(753)		IMO	0	2,800	(2,800)
	SOUTHIMP	0	1,375	(1,375)		MISO	(8,681)	(968)	(7,713)
CPLE		5,666	281	5,385		SOUTHIMP	0	725	(725)
	CPLEEXP	0	(296)	296	NEPT		(2,322)	(2,322)	0
	CPLEIMP	0	672	(672)		NEPTUNE	(2,322)	(2,322)	0
	DUKIMP	0	2	(2)	NIPS		(3,309)	(164)	(3,145)
	SOUTHEXP	0	(14)	14		MISO	(3,309)	(164)	(3,145)
	SOUTHIMP	5,666	(83)	5,749	NYIS		(3,855)	(3,903)	48
CPLW		(1,103)	0	(1,103)		IMO	0	(23)	23
	SOUTHIMP	(1,103)	0	(1,103)		NYIS	(3,855)	(3,880)	25
CWLP		(289)	0	(289)	OVEC		9,771	6,756	3,015
	MISO	(289)	0	(289)		OVEC	9,771	6,756	3,015
DUK		481	1,391	(910)	TVA		4,331	2,374	1,957
	DUKEXP	0	(265)	265		SOUTHEXP	0	(254)	254
	DUKIMP	0	805	(805)		SOUTHIMP	4,331	2,628	1,703
	NCMPAEXP	0	(2)	2	WEC		4,534	(1,041)	5,575
	NCMPAIMP	0	427	(427)		MISO	4,534	(1,041)	5,575
	SOUTHEXP	0	(213)	213	HUDS		(82)	(82)	0
	SOUTHIMP	481	639	(158)		HUDSONTP	(82)	(82)	0
EKPC		957	(569)	1,526	**Grand Total**	**Grand Total**	**3,474**	**3,316**	**158**
	MISO	957	134	822					
	SOUTHEXP	0	(790)	790					
	SOUTHIMP	0	86	(86)					

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 for the first nine months of 2013, 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 (2,800 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 23 GWh).

Table 9-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through September, 2013

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(296)	296	NORTHWEST		(1,695)	(25)	(1,670)
	CPLE	0	(296)	296		ALTE	0	(1)	1
CPLEIMP		0	672	(672)		AMIL	0	(1)	1
	CPLE	0	672	(672)		CIN	0	(28)	28
DUKEXP		0	(265)	265		MEC	(1,695)	6	(1,701)
	DUK	0	(265)	265	NYIS		(3,855)	(3,127)	(728)
DUKIMP		0	807	(807)		CIN	0	753	(753)
	CPLE	0	2	(2)		NYIS	(3,855)	(3,880)	25
	DUK	0	805	(805)	OVEC		9,771	6,756	3,015
IMO		0	5,000	(5,000)		OVEC	9,771	6,756	3,015
	CIN	0	1,569	(1,569)	SOUTHEXP		0	(1,319)	1,319
	IPL	0	653	(653)		CPLE	0	(14)	14
	MECS	0	2,800	(2,800)		DUK	0	(213)	213
	NYIS	0	(23)	23		EKPC	0	(790)	790
LINDENVFT		(835)	(835)	0		IPL	0	(2)	2
	LIND	(835)	(835)	0		LGEE	0	(47)	47
MISO		(8,246)	(10,729)	2,483		TVA	0	(254)	254
	ALTE	(4,604)	(3,107)	(1,497)	SOUTHIMP		10,737	8,695	2,041
	ALTW	(1,731)	(139)	(1,592)		ALTE	0	1	(1)
	AMIL	8,443	730	7,713		AMIL	0	279	(279)
	CIN	(3,931)	(1,368)	(2,562)		CIN	0	1,375	(1,375)
	CWLP	(289)	0	(289)		CPLE	5,666	(83)	5,749
	EKPC	957	134	822		CPLW	(1,103)	0	(1,103)
	IPL	365	(595)	960		DUK	481	639	(158)
	MEC	0	(4,211)	4,211		EKPC	0	86	(86)
	MECS	(8,681)	(968)	(7,713)		IPL	0	374	(374)
	NIPS	(3,309)	(164)	(3,145)		LGEE	1,361	2,326	(964)
	WEC	4,534	(1,041)	5,575		MEC	0	346	(346)
NCMPAEXP		0	(2)	2		MECS	0	725	(725)
	DUK	0	(2)	2		TVA	4,331	2,628	1,703
NCMPAIMP		0	427	(427)	SOUTHWEST		0	(41)	41
	DUK	0	427	(427)		AMIL	0	(41)	41
NEPTUNE		(2,322)	(2,322)	0	HUDSONTP		(82)	(82)	0
	NEPT	(2,322)	(2,322)	0		HUDS	(82)	(82)	0
					Grand Total	Grand Total	3,474	3,316	158

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 uses the LMP at nine buses within MISO to calculate the PJM/MISO Interface price, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[40,41] Differences in interface price calculations between PJM and MISO limit the ability for price convergence. The use of a common interface price definition including similarly located buses and comparable weights for those buses would help to converge the prices by eliminating artificial limits to that convergence. The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number

40 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 9, 2013). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

41 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010) (Accessed October 10, 2013).

of external buses and selecting buses in close proximity on either side of the border with comparable bus weights.

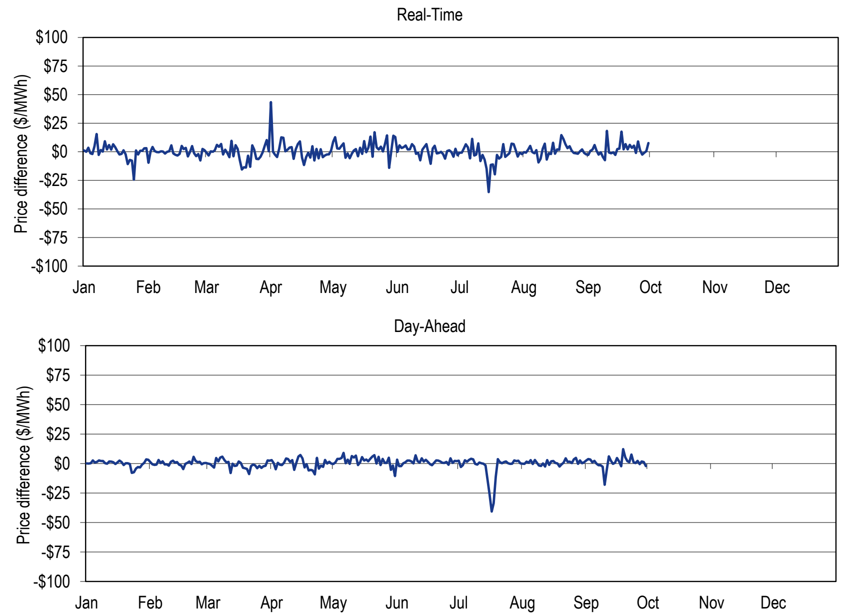
Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first nine months of 2013, 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 2013, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $30.37 while the MISO LMP at the border was $30.84, a difference of $0.48. While the average hourly LMP difference at the PJM/MISO border was only $0.48, the average of the absolute values of the hourly differences was $8.89. The average hourly flow during the first nine months of 2013 was -1,142 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 only 47.0 percent of hours in the first nine months of 2013. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $11.26. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $7.21. In the first nine months of 2013, 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 $10.86. 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 $13.67. 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 $13.42. 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 $5.72.

In the first nine months of 2013, the day-ahead PJM average hourly LMP at the PJM/MISO border was $31.05 while the MISO LMP at the border was $31.20, a difference of $0.15.

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).

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through September, 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/MISO Interface

During the first nine months of 2013, the direction of hourly energy flows was consistent with PJM and MISO Interface Price differentials in 3,078 hours (47.0 percent of all hours), and was inconsistent with price differentials in 3,473 hours (53.0 percent of all hours). Table 9-23 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 3,473 hours where flows were uneconomic, 3,000 of those hours (86.4 percent) had a price difference greater than or equal to $1.00 and 1,221 of all uneconomic hours (35.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $272.26. Of the 3,078 hours where flows were economic, 2,682 of those hours (87.1 percent) had a price difference greater than or equal to $1.00 and 1,645 of all economic hours (53.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $887.50.

Table 9-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through September, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	3,473	100.0%	3,078	100.0%
$1.00	3,000	86.4%	2,682	87.1%
$5.00	1,221	35.2%	1,645	53.4%
$10.00	557	16.0%	974	31.6%
$15.00	340	9.8%	651	21.2%
$20.00	220	6.3%	431	14.0%
$25.00	155	4.5%	311	10.1%
$50.00	32	0.9%	99	3.2%
$75.00	12	0.3%	48	1.6%
$100.00	6	0.2%	28	0.9%
$200.00	1	0.0%	5	0.2%
$300.00	0	0.0%	3	0.1%
$400.00	0	0.0%	1	0.0%
$500.00	0	0.0%	1	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.[42]

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

In the first nine months of 2013, 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 2013, 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 2013, the PJM average hourly LMP at the PJM/NYISO border was $41.85 while the NYISO LMP at the border was $41.39, a difference of $0.45. While the average hourly LMP difference at the PJM/NYISO border was only $0.45, the average of the absolute value of the hourly difference was $13.69. The average hourly flow during the first nine months of 2013 was -564 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 53.1 percent of the hours in the first nine months of 2013. In the first nine months of 2013, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $13.68. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $13.72. In the first nine months of 2013, 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 $13.44. 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 $15.59. 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 $13.65. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and

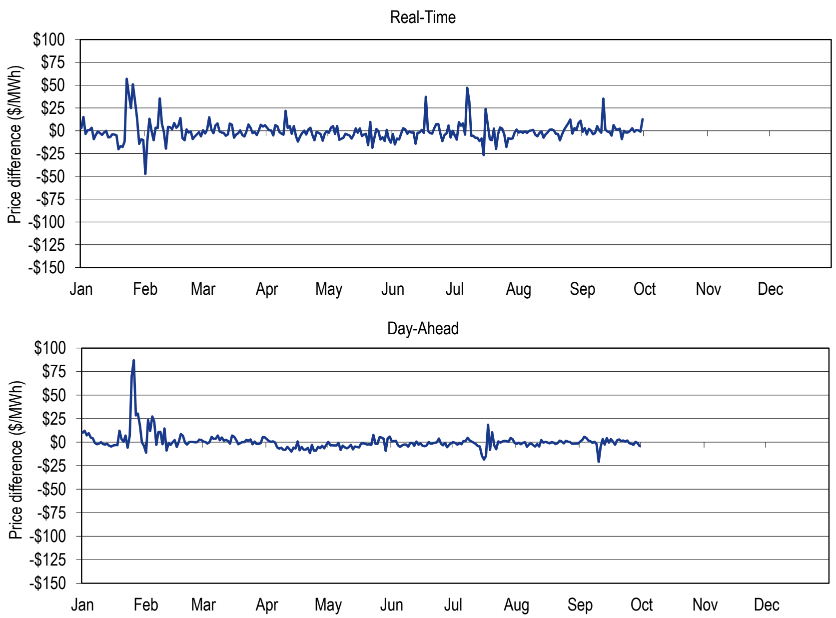
42 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

when power flows were from PJM to NYISO, the average price difference was $13.73.

In the first nine months of 2013, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $42.17 while the NYIS LMP at the border was $42.41, a difference of $0.24.

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, 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/NYISO Interface

During the first nine months of 2013, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,480 (53.1 percent of all hours), and was inconsistent with price differences in 3,071 hours (46.9 percent of all hours). Table 9-24 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 3,071 hours where flows were uneconomic, 2,767 of those hours (90.1 percent) had a price difference greater than or equal to $1.00 and 1,777 of all uneconomic hours (57.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $348.46. Of the 3,480 hours where flows were economic, 3,188 of those hours (91.6 percent) had a price difference greater than or equal to $1.00 and 2,026 of all economic hours (58.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $812.91.

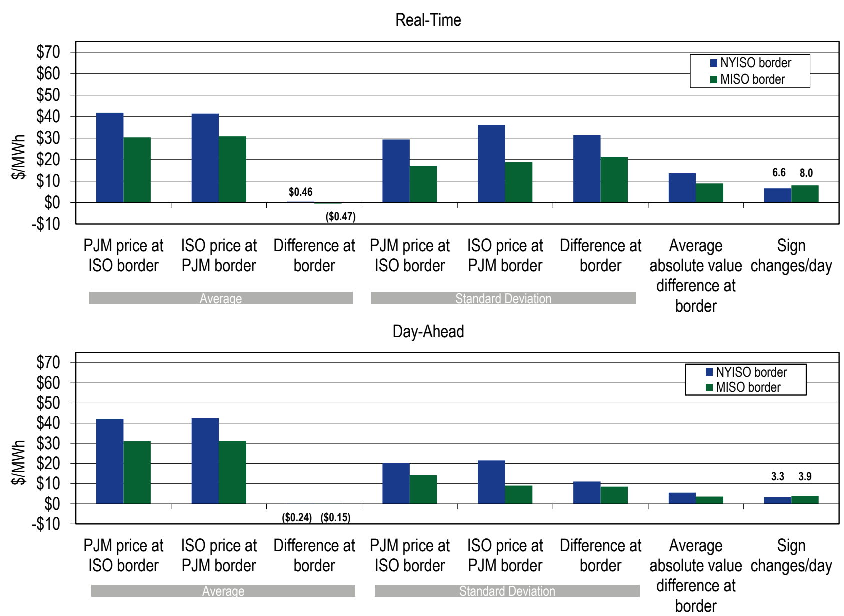
Table 9-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through September, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	3,071	100.0%	3,480	100.0%
$1.00	2,767	90.1%	3,188	91.6%
$5.00	1,777	57.9%	2,026	58.2%
$10.00	1,059	34.5%	1,094	31.4%
$15.00	708	23.1%	708	20.3%
$20.00	507	16.5%	498	14.3%
$25.00	400	13.0%	357	10.3%
$50.00	186	6.1%	162	4.7%
$75.00	94	3.1%	95	2.7%
$100.00	46	1.5%	69	2.0%
$200.00	8	0.3%	15	0.4%
$300.00	2	0.1%	5	0.1%
$400.00	0	0.0%	2	0.1%
$500.00	0	0.0%	2	0.1%

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.

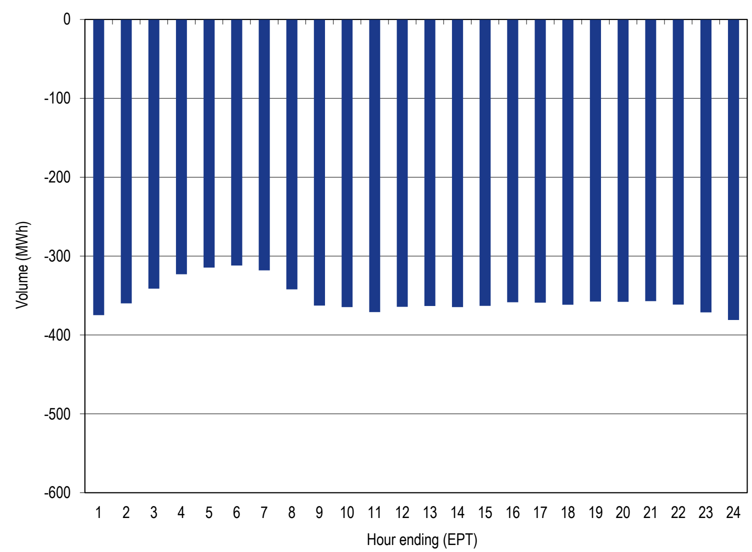
Figure 9-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through September, 2013



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 2013, the direction of the average hourly flow 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 2013, the PJM average hourly LMP at the Neptune Interface was $41.72 while the NYISO LMP at the Neptune Bus was $66.36, a difference of $24.64.[43] While the average hourly LMP difference at the PJM/Neptune border was $24.64, the average of the absolute value of the hourly difference was $35.85. The average hourly flow during the first nine months of 2013 was -354 MW.[44] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 69.5 percent of the hours in the first nine months of 2013. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average hourly price difference was $43.01. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $18.91.

Figure 9-7 Neptune hourly average flow: January through September, 2013



43 In the first nine months of 2013, there were 1,128 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 $42.62 while the NYISO LMP at the Neptune Bus during non-zero flows was $64.19, a difference of $21.57.

44 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -428 MW.

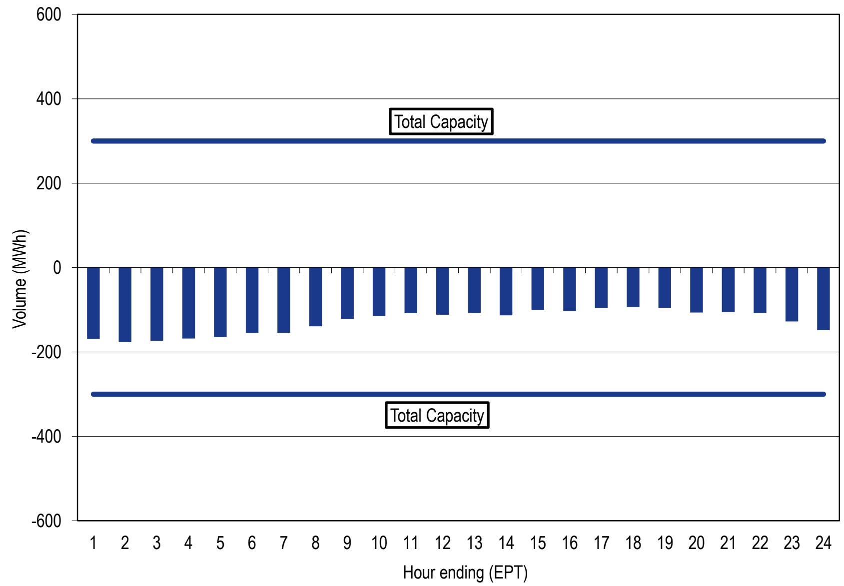
Linden Variable Frequency Transformer (VFT) facility

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 2013, the direction of the average hourly flow 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 2013, the PJM average hourly LMP at the Linden Interface was $41.18 while the NYISO LMP at the Linden Bus was $49.71, a difference of $8.53.[45] While the average hourly LMP difference at the PJM/Linden border was $8.53, the average of the absolute value of the hourly difference was $18.86. The average hourly flow during the first nine months of 2013 was -127 MW.[46] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 65.8 percent of the hours in the first nine months of 2013. When the NYISO/Linden Interface price was greater than the PJM/LIND Interface price, the average hourly price difference was $21.18. When the PJM/LIND Interface price was greater than the NYISO/Linden Interface price, the average price difference was $14.61.

45 In the first nine months of 2013, there were 1,351 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 $41.23 while the NYISO LMP at the Neptune Bus during non-zero flows was $48.95, a difference of $7.72.

46 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Linden VFT line was -161 MW.

Figure 9-8 Linden hourly average flow: January through September, 2013[47]



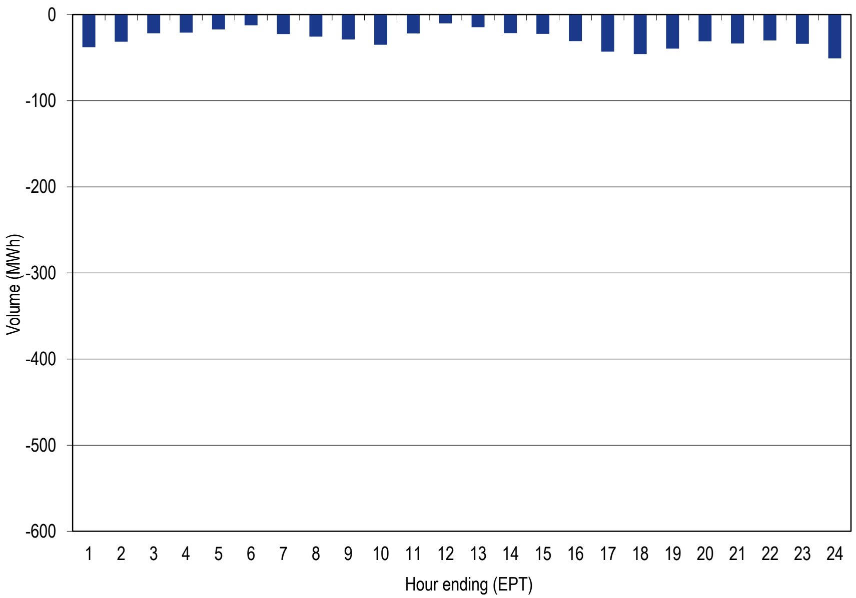
Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) line began commercial operation on June 3, 2013. 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 (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 four months of operations, the direction of the average

47 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.

hourly flow was consistent 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 $41.47 while the NYISO LMP at the Hudson Bus was $44.11, a difference of $2.64.[48] While the average hourly LMP difference at the PJM/Hudson border was $2.64, the average of the absolute value of the hourly difference was $8.09. The average hourly flow during the first four months of operations was -22 MW.[49] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 60.9 percent of the hours in the first four months of operations. When the NYISO/Hudson Interface price was greater than the PJM/HUDS Interface price, the average hourly price difference was $20.80. When the PJM/HUDS Interface price was greater than the NYISO/Hudson Interface price, the average price difference was $16.11.

Figure 9-9 Hudson hourly average flow: June through September, 2013



48 In the first four months of operations, there were 2,987 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $48.65 while the NYISO LMP at the Hudson Bus during non-zero flows was $55.00, a difference of $6.35.

49 The average hourly flow during the first four months of operations, ignoring hours with no flow, on the Hudson line was -120 MW.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with the NYISO, an implemented operating agreement with MISO, 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[50]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[51]

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 nine 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.[52]

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

50 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 10, 2013).

51 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>.

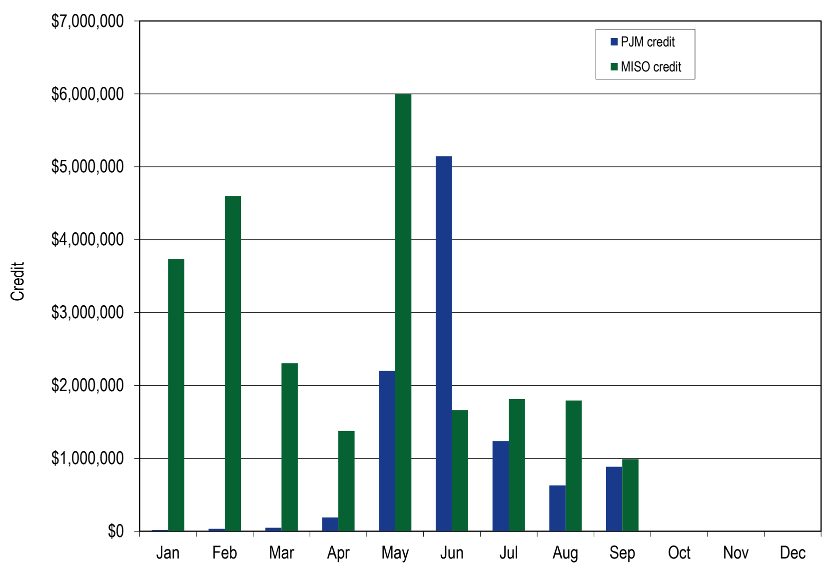
52 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of August 6, 2013, PJM had 166 flowgates eligible for M2M coordination. Between August 6, 2013 and September 30, 2013, PJM added five and deleted 21 flowgates, leaving 150 flowgates eligible for M2M coordination as of October 1, 2013. As of August 6, 2013, MISO had 269 flowgates eligible for M2M coordination. Between August 6, 2013 and September 30, 2013, MISO added 51 and deleted 33 flowgates, leaving 287 flowgates eligible for M2M coordination as of October 1, 2013.

During the first nine months of 2013, 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, 2013[53]



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

PJM and New York Independent System Operator Joint Operating Agreement (JOA)[54]

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 factor impacts. PJM uses two buses within NYISO to calculate the PJM/MISO Interface pricing point LMP while The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) using 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, 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 RCF's are subject to the market to market congestion management process.

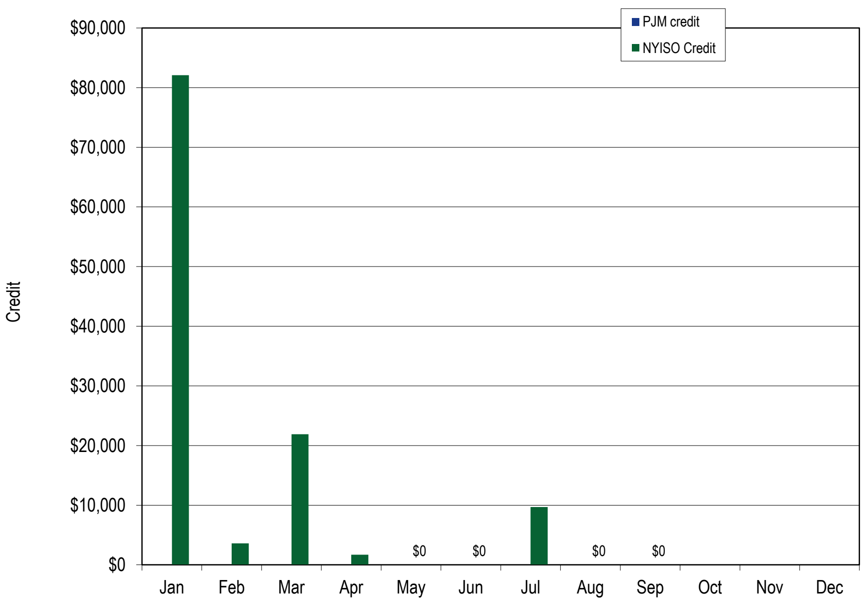
In the first nine months of 2013, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that 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

54 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (April 15, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed October 10, 2013).

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.

During the first nine months of 2013, 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, 2013[55]

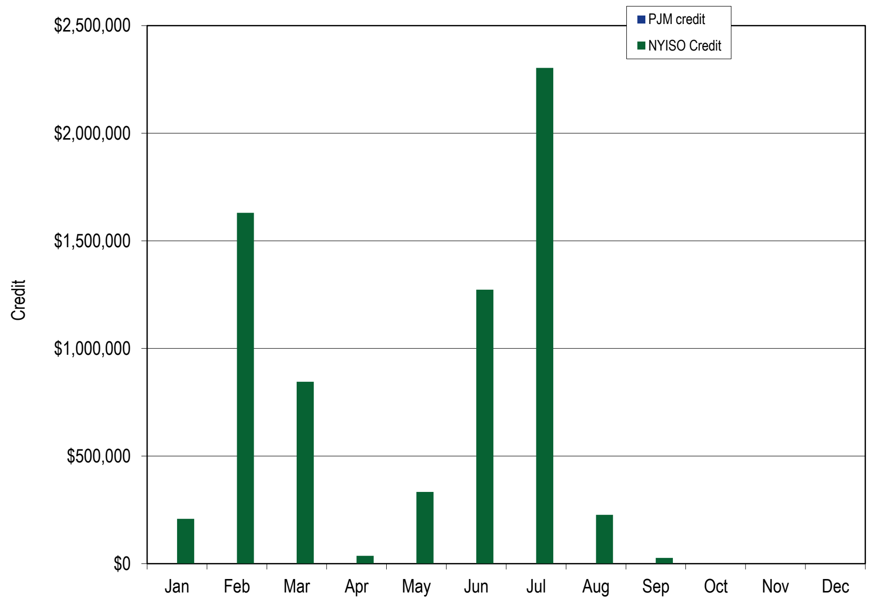


The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the NYISO – PJM interface. 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.[56] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during 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 2013, 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.

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

56 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (April 15, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed October 10, 2013).

Figure 9-12 Credits for coordinated congestion management (Ramapo PARs): January through September, 2013[57]



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 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, and, in the first nine months of 2013, there were no developments. The agreement continued to be in effect in the first nine months of 2013.

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.[58] On January 20, 2011, the Commission conditionally accepted the compliance filing.

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems. The parties meet on a yearly basis, and, in the first nine months of 2013, there were no developments. The agreement remained in effect in the first nine months of 2013.

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

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

Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[59]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[60] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[61] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. However, the MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

Table 9-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$33.38	$34.07	$33.59	$33.59	($0.21)	$0.48
PEC	$33.79	$34.87	$33.59	$33.59	$0.21	$1.28
NCMPA	$33.73	$33.84	$33.59	$33.59	$0.14	$0.25

59 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (Accessed October 10, 2013).
60 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).
61 See Docket Nos. ER12-1338-000 and ER12-1343-000.

Table 9-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$34.61	$35.15	$34.34	$34.27	$0.27	$0.88
PEC	$34.99	$35.61	$34.34	$34.27	$0.64	$1.34
NCMPA	$34.88	$34.97	$34.34	$34.27	$0.53	$0.70

Other Agreements/Protocols with Bordering Areas

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

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.[62] 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.[63]

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[64] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special protocol indefinitely.[65] The settlement defined ConEd's cost responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. ConEd 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.[66] ConEd's rolled over service became effective on May 1, 2012. The additional transmission charges have been included in the wheeling agreement data as shown in Table 9-27 below reflecting those charges effective May 1, 2012.

62 See "Section 4 – Operating Reserve" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.
63 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.
64 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.
65 132 FERC ¶ 61,221 (2010).
66 The terms of the settlement state that ConEd 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.

Table 9-27 Con Edison and PSE&G wheeling agreement data: January through September, 2013

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$6,666,452	$15,964	$6,682,416	$0	$0	$0
Congestion Credit			$2,806,474			$0
Adjustments and Transmission Charges			($27,175,184)			$1,920
Net Charge			$31,051,125			($1,920)

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 45 TLRs of level 3a or high in the first nine months of 2013, compared to 29 TLRs issued in the first nine months of 2012. The number of different flowgates for which PJM declared TLRs increased from nine in the first nine months of 2012 to 23 in the first nine months of 2013. The total MWh of transaction curtailments increased by 6.8 percent, from 125,339 MWh in the first nine months of 2012 to 133,869 MWh in the first nine months of 2013.

MISO called more TLRs of level 3a or higher in the first nine months of 2013 than in the first nine months of 2012. MISO TLRs increased from 118 in the first nine months of 2012 to 285 in the first nine months of 2013.

NYISO called fewer TLRs of level 3a or higher in the first nine months of 2013 than in the first nine months of 2012. NYISO TLRs decreased from 55 in the first nine months of 2012 to 3 in the first nine months of 2013.

Table 9-28 PJM MISO, and NYISO TLR procedures: January, 2010 through September, 2013[67]

	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-10	6	23	20	3	5	4	18,393	13,387	60,427
Feb-10	1	9	19	1	7	3	1,249	13,095	69,569
Mar-10	6	18	21	3	10	6	2,376	27,412	78,366
Apr-10	15	40	14	7	11	2	26,992	29,832	59,041
May-10	11	20	7	4	12	4	22,193	54,702	10,463
Jun-10	19	19	13	6	8	6	64,479	183,228	23,969
Jul-10	15	25	4	8	8	3	44,210	169,667	2,262
Aug-10	12	22	0	9	7	0	32,604	189,756	0
Sep-10	11	15	1	7	7	1	82,066	32,782	232
Oct-10	4	26	1	3	12	1	2,305	29,574	0
Nov-10	1	25	0	1	10	0	59	66,113	0
Dec-10	9	7	4	6	5	1	18,509	5,972	4,224
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

67 The curtailment volume for PJM TLRs was taken from the individual NERC TLR history reports as posted in the Interchange Distribution Calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLRs was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx> (Accessed October 10, 2013).

Table 9-29 Number of TLRs by TLR level by reliability coordinator: January through September, 2013

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2013	ICTE	0	0	0	0	0	0	0
	MISO	91	32	1	107	54	0	285
	NYIS	3	0	0	0	0	0	3
	ONT	7	0	0	0	0	0	7
	PJM	24	19	0	1	1	0	45
	SOCO	0	0	0	0	0	0	0
	SWPP	241	83	0	54	12	0	390
	TVA	26	25	1	5	5	0	62
	VACS	3	3	0	0	0	0	6
Total		395	162	2	167	72	0	798

On February 9, 2013, PJM issued a TLR level 5a. A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point-to-point transmission service, to flow.[68] The TLR 5a, issued on February 9, 2013, was required to address system operating limits on the Bridgewater to Middlesex 230 kV line for the loss of the Smithburg to East Windsor 230 kV line in northern New Jersey, and resulted in the curtailment of 223 MWh of transactions utilizing Firm transmission.

On September 11, 2013, PJM issued a TLR level 5b. A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL. The TLR 5b, issued on September 11, 2013, was required to address system operating limits on the Bridgewater to Middlesex 230 kV line for the loss of Red Oak A and B units in northern New Jersey, and resulted in the curtailment of 1,480 MWh of transactions utilizing firm transmission.

Between January 1, 2003, and February 9, 2013, PJM had only issued 20 TLR's of level 5a or 5b, and none since 2008.

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.[69]

Following elimination of the requirement to procure 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 Market increased to 105,472 bids per day, with an average cleared volume of 1,221,114 MWh per day, in the first nine months of 2013, compared to an average of 58,273 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012 (See Figure 9-13).

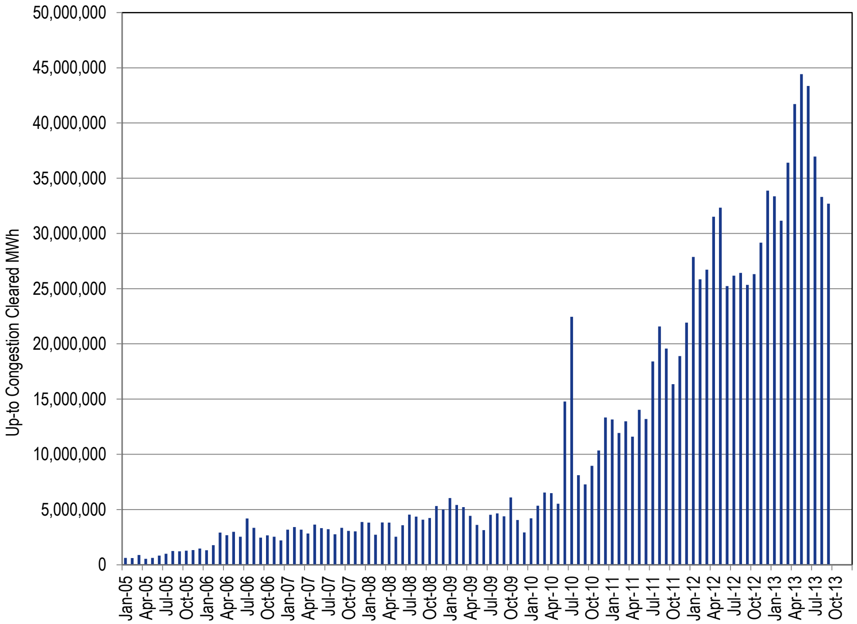
Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Despite that, up-to congestion transactions do not pay operating reserves charges. Up-to congestion transactions also significantly affect FTR funding. The FTR forfeiture rule does not currently apply to UTCs.

68 See the *2012 State of the Market Report for PJM*, Volume II, "Appendix E - Interchange Transactions," for a discussion on all TLR levels and the historical volumes of TLR's initiated by PJM and all other reliability coordinators in the Eastern Interconnection.

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

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges. The level of the fee should be determined based on the method defined in the State of the Market Report.[70]

Figure 9-13 Monthly up-to congestion cleared bids in MWh: January, 2005 through September, 2013



70 See the *2013 Quarterly State of the Market Report for PJM: January to September*, Section 4, "Operating Reserves."

Table 9-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through September, 2013

	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
TOTAL	986,228,391	953,011,602	45,472,967	1,000,637,907	2,985,350,867	22,180,464	19,800,506	1,024,433	25,869,008	68,874,411	363,374,731	353,501,206	20,031,738	294,792,983	1,031,700,657	9,163,568	8,186,546	430,622	8,982,925	26,763,661

In the first nine months of 2013, the cleared MW volume of up-to congestion transactions was comprised of 9.9 percent imports, 11.7 percent exports, 0.9 percent wheeling transactions and 77.5 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 also recommends that PJM, NYISO, MISO and Ontario work together to create business rules that prevent sham scheduling among and between the RTO/ISO markets.

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.[71] 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 double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing. Because 5,022 GWh of the 5,045 GWh of net transactions between PJM and IESO wheeled through MISO during the first nine months of 2013, (see Table 9-22), the MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink

71 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 9, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

in the IESO balancing authority until the stakeholder process determines an alternative approach to pricing these transactions.

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.

CTS transactions are evaluated based on the spread bid, which limits the amount 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 proceed with the development of 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.

Elimination of Sources and Sinks

The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets. On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving non-firm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

Total uncollected congestion charges during the first nine months of 2013 were -$2,860, compared to -$32 in the first nine months of 2012 (Table 9-31). If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction. Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case for the net uncollected congestion charges in the first nine months of 2013. In other words, when market participants utilize the not willing to pay congestion product, it also means that they are not willing to receive congestion credits when the LMP at the source is greater than the LMP at the sink. The fact that there was a total negative congestion collection in the first nine months of 2013, for not willing to pay congestion transactions, means that market participants who utilized the not willing to pay congestion transmission option for their transactions had transactions that flowed in the direction opposite to congestion.

The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces. 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. 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 9-31 Monthly uncollected congestion charges: January, 2010 through September, 2013

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

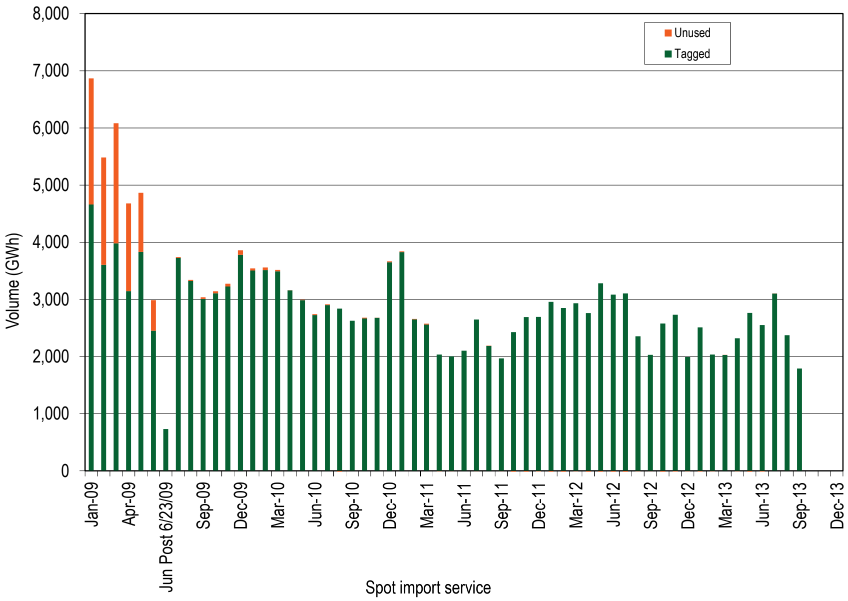
Spot Imports

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.[72] 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.

Due to the timing requirements to submit transactions in the NYISO market, the limitation of ATC for spot market imports at the NYISO Interface experiences the most issues with potential hoarding. 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.

72 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>.

Figure 9-14 Spot import service utilization: January, 2009 through September, 2013



Real-Time Dispatchable Transactions

Real-Time Dispatchable Transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction.

Dispatchable transactions were a valuable tool for market participants when implemented. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants, but the risk to other market participants is substantial, as they are subject to paying the resultant operating reserve credits.

Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. There have been no balancing operating reserve credits paid to dispatchable transactions since July, 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that no dispatchable schedules were submitted during the first nine months of 2013.