# 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 six months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market.[1] During the first six months of 2013, the real-time net interchange of 4,023.3 GWh was greater than net interchange of 2,351.1 GWh in the first six months of 2012.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first six months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market. During the first six months of 2013, the total day-ahead net interchange of -9,161.6 GWh was greater than net interchange of -1,947.9 GWh during the first six months of 2012.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first six months of 2013, gross imports in the Day-Ahead Energy Market were 158.0 percent of gross imports in the Real-Time Energy Market (427.8 percent during the first six months of 2012), gross exports in the Day-Ahead Energy Market were 242.0 percent of the gross exports in the Real-Time Energy Market (487.3 percent during the first six months of 2012).

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first six 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 six 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 six 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 six months of 2013, there were net scheduled exports at nine 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 six months of 2013, up-to congestion transactions had net exports at five 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 six months of 2013, the direction of the average hourly flow was inconsistent 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 only 46.5 percent of hours in the first six months of 2013.

- **PJM and New York ISO Interface Prices.** In the first six 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 55.9 percent of the hours in the first six months of 2013.

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1 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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 six 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 six months of 2013 was -293 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 78.3 percent of the hours in the first six months of 2013.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first six 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 six months of 2013 was -139 MW.[6] The direction of flows was consistent with price differentials in 70.6 percent of the hours in the first six 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 month 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 month of operation was -17 MW.[8] The direction of flows was consistent with price differentials in 60.9 percent of the hours during June, 2013.

## 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 six months of 2013, net scheduled interchange was 2,989 GWh and net actual interchange was 3,058 GWh, a difference of 69 GWh. For the first six months of 2012, net scheduled interchange was 1,666 GWh and net actual interchange was 1,480 GWh, a difference of 185 GWh. This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 23 TLRs of level 3a or higher in the first six months of 2013, compared to eight TLRs issued in the first six months of 2012.

- **Up-To Congestion.** Following elimination of the requirement to procure transmission service for up-to congestion transactions in 2010, the volume of transactions increased significantly. The volumes of submitted and cleared up-to congestion bids continued to increase following the business rule change on November 1, 2012, which eliminated the requirement for either the source or sink of an up-to congestion transaction to be at an interface. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 107,215 bids per day, with an average cleared volume of 1,272,955 MWh per day, in the first six months of 2013, compared to an average of 54,180 bids per day, with an average cleared volume of 931,553 MWh per day, in the first six months of 2012. (Figure 8-13).

- **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

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3  In the first six months of 2013, there were 833 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 $40.03 while the NYISO LMP at the Neptune Bus during non-zero flows was $71.87, a difference of $31.84.

4  The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -363 MW.

5  In the first six months of 2013, there were 841 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 $41.32 while the NYISO LMP at the Neptune Bus during non-zero flows was $51.64, a difference of $10.32.

6  The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Linden VFT line was -173 MW.

7  In its first month of operation, there were 550 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $37.17 while the NYISO LMP at the Hudson Bus during non-zero flows was $39.26, a difference of $2.09.

8  The average hourly flow during the first months of operations, ignoring hours with no flow, on the Hudson line was -147 MW.

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 all 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.

## 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 six months of 2013, including evolving

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

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 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.

In the first six 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 53.5 percent of the hours for transactions between PJM and MISO and for 44.1 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.

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 equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

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. This 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.

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.[10] 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 six months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in all months (Figure 8-1).[11] During the first six months of 2013, the total real-time net interchange of 4,023.3 GWh was greater than the net interchange of 2,351.1 GWh during the first six months of 2012. During the first six months of 2013, the peak month for net importing interchange was May, 846.7 GWh; in 2012 it was May, 798.4 GWh. Gross monthly export volumes during the first six months of 2013 averaged 3,078.5 GWh compared to 3,362.9 GWh for the first six months of 2012, while gross monthly imports during the first six months of 2013 averaged 3,749.1 GWh compared to 3,754.7 GWh during the first six months of 2012.

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10  See Docket Nos. ER12-1338-000 and ER12-1343-000.
11  Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

During the first six months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 8-1). During the first six months of 2013, the total day-ahead net interchange of -9,161.6 GWh was greater than the net interchange of -1,947.9 GWh during the first six months of 2012. During the first six months of 2013, the peak month for net exporting interchange was January, -2,602.8 GWh; in 2012 it was January, -1,847.5 GWh. Gross monthly export volumes during the first six months of 2013 averaged 7,449.5 GWh compared to 16,387.7 GWh for the first six months of 2012, while gross monthly imports during the first six months of 2013 averaged 5,922.6 GWh compared to 16,063.0 GWh during the first six 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).[12]

Figure 8-1 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 8-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

In the first six months of 2013, import up-to congestion transactions accounted for 73.4 percent of all scheduled import MW transactions, export up-to congestion transactions accounted 69.5 percent of all scheduled export MW transactions and net up-to congestion transactions accounted for 54.4 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 10,548 bids per day, with an average cleared

volume of 303,215 MWh per day, in the first six months of 2013, compared to an average of 21,929 bids per day, with an average cleared volume of 931,553 MWh per day, in the first six 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 38,471 bids per day, with an average cleared volume of 1,272,955 MWh per day, in the first six months of 2013, compared to an average of 21,929 bids per day, with an average cleared volume of 931,553 MWh per day, in the first six months of 2012.

In the first six months of 2013, gross imports in the Day-Ahead Energy Market were 158.0 percent of gross imports in the Real-Time Energy Market (427.8 percent during the first six months of 2012), gross exports in the Day-Ahead Energy Market were 242.0 percent of gross exports in the Real-Time Energy Market (487.3 percent during the first six months of 2012). In the first six months of 2013, net interchange was -9,161.6 GWh in the Day-Ahead Energy Market and 4,023.3 GWh in the Real-Time Energy Market compared to -1,947.9 GWh in the Day-Ahead Energy Market and 2,351.1 GWh in the Real-Time Energy Market for the first six 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.[13] For the first six 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.

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12 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 August 7, 2013).

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

**Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: January through June, 2013**
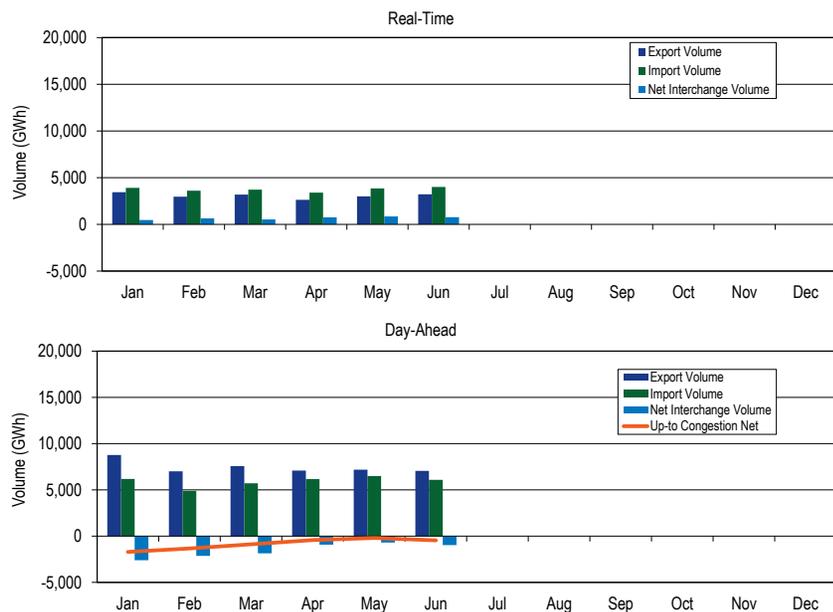


Figure 8-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through June, 2013. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time 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 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January, 1999 through June, 2013**
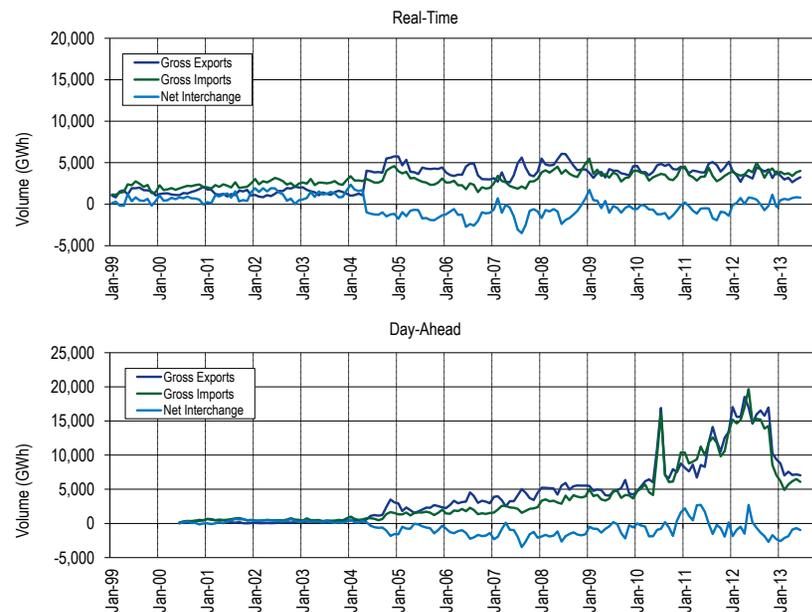


## Real-Time Interface Imports and Exports

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 8-16 for a list of active interfaces during the first six months of 2013. Figure 8-3 shows the approximate geographic location of the interfaces. In the first six 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 8-1 through Table 8-3 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 six months of 2013 in Table 8-1, while gross imports and exports are shown in Table 8-2 and Table 8-3.

In the Real-Time Energy Market, for the first six months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.[14] The top three net exporting interfaces in the Real-Time Energy Market accounted for 65.5 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 23.9 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 23.6 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 18.1 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 42.3 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 62.9 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 29.9 percent, PJM/Tennessee Valley Authority (TVA) with 17.5 percent and PJM/Michigan Electric Coordinated System (MECS) with 15.4 percent of the net import volume.[15]

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.[16] 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.

**Table 8-1 Real-time scheduled net interchange volume by interface (GWh): January through June, 2013**

| | | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|---|
| CPLE | | (30.6) | (38.3) | (48.4) | (33.1) | (25.3) | 188.1 | 12.4 |
| CPLW | | 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 | 1,043.4 |
| 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 | 1,496.4 |
| MEC | | (484.1) | (390.8) | (158.9) | (421.4) | (509.1) | (464.2) | (2,428.5) |
| MISO | | 283.1 | 518.3 | 572.6 | 622.4 | 103.4 | 62.0 | 2,161.9 |
| | ALTE | (306.7) | (176.9) | (239.3) | (214.3) | (454.5) | (449.7) | (1,841.6) |
| | ALTW | (9.0) | (4.5) | (3.0) | (3.8) | (25.3) | (40.2) | (85.7) |
| | AMIL | 181.7 | 153.6 | 181.5 | 150.2 | 170.1 | 12.0 | 849.1 |
| | CIN | 253.3 | 285.4 | 349.7 | 272.0 | 129.6 | 350.0 | 1,640.0 |
| | CWLP | 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 | 242.5 |
| | MECS | 322.3 | 298.9 | 322.5 | 433.4 | 529.0 | 291.8 | 2,197.8 |
| | NIPS | (22.9) | (12.5) | (22.0) | (25.6) | (71.6) | (5.0) | (159.5) |
| | WEC | (92.1) | (73.8) | (80.5) | (64.0) | (144.7) | (225.6) | (680.7) |
| NYISO | | (1,047.1) | (1,018.0) | (1,100.9) | (313.3) | (216.5) | (609.2) | (4,305.0) |
| | HUDS | | | | | | (25.6) | (25.6) |
| | LIND | (165.2) | (149.8) | (91.6) | (64.9) | (77.0) | (55.8) | (604.5) |
| | NEPT | (270.9) | (245.9) | (239.2) | (247.1) | (102.5) | (167.8) | (1,273.4) |
| | NYIS | (611.0) | (622.3) | (770.1) | (1.3) | (37.0) | (360.0) | (2,401.6) |
| OVEC | | 798.2 | 713.5 | 585.0 | 542.8 | 712.0 | 908.3 | 4,259.8 |
| TVA | | 643.8 | 600.0 | 383.6 | 249.0 | 392.2 | 217.6 | 2,486.2 |
| Total | | 470.4 | 639.5 | 530.6 | 757.9 | 846.7 | 778.1 | 4,023.3 |

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14 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.
15 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)).
16 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (Accessed July 17, 2013).

Table 8-2 Real-time scheduled gross import volume by interface (GWh): January through June, 2013

|  | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| CPLE | 1.4 | 0.1 | 1.6 | 0.0 | 2.0 | 219.4 | 224.4 |
| CPLW | 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 | 1,296.3 |
| 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 | 1,519.9 |
| MEC | 0.2 | 48.2 | 320.6 | 6.2 | 0.0 | 0.0 | 375.4 |
| MISO | 1,026.7 | 971.1 | 1,110.5 | 1,199.0 | 1,264.4 | 1,193.4 | 6,765.1 |
| ALTE | 0.0 | 1.1 | 0.0 | 0.0 | 0.0 | 0.0 | 1.1 |
| ALTW | 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 | 1,090.3 |
| CIN | 374.5 | 394.7 | 455.5 | 438.9 | 358.2 | 519.7 | 2,541.6 |
| CWLP | 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 | 622.1 |
| MECS | 349.1 | 321.6 | 338.3 | 458.2 | 621.9 | 418.4 | 2,507.5 |
| NIPS | 0.2 | 0.0 | 0.0 | 2.4 | 0.0 | 0.0 | 2.6 |
| WEC | 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 | 5,263.9 |
| HUDS |  |  |  |  |  | 0.0 | 0.0 |
| LIND | 0.6 | 10.4 | 7.5 | 13.5 | 7.8 | 10.2 | 50.1 |
| NEPT | 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 | 5,213.8 |
| OVEC | 798.3 | 713.5 | 585.1 | 543.8 | 728.4 | 916.1 | 4,285.2 |
| TVA | 689.8 | 630.0 | 399.1 | 261.5 | 431.9 | 265.9 | 2,678.2 |
| Total | 3,915.7 | 3,609.5 | 3,722.4 | 3,393.4 | 3,842.5 | 4,010.9 | 22,494.5 |

Table 8-3 Real-time scheduled gross export volume by interface (GWh): January through June, 2013

|  | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| CPLE | 31.9 | 38.4 | 50.0 | 33.1 | 27.3 | 31.3 | 212.0 |
| CPLW | 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 | 252.9 |
| 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 | 23.5 |
| MEC | 484.4 | 439.0 | 479.6 | 427.6 | 509.1 | 464.2 | 2,803.8 |
| MISO | 743.5 | 452.8 | 537.9 | 576.7 | 1,161.0 | 1,131.4 | 4,603.2 |
| ALTE | 306.7 | 178.0 | 239.3 | 214.3 | 454.5 | 449.7 | 1,842.6 |
| ALTW | 9.0 | 4.5 | 3.0 | 3.8 | 25.3 | 40.2 | 85.7 |
| AMIL | 25.3 | 23.5 | 33.6 | 48.0 | 43.7 | 67.0 | 241.2 |
| CIN | 121.2 | 109.3 | 105.8 | 166.9 | 228.6 | 169.7 | 901.6 |
| CWLP | 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 | 379.6 |
| MECS | 26.8 | 22.7 | 15.8 | 24.8 | 93.0 | 126.6 | 309.7 |
| NIPS | 23.0 | 12.5 | 22.0 | 28.0 | 71.6 | 5.0 | 162.1 |
| WEC | 92.1 | 73.8 | 80.5 | 64.0 | 144.7 | 225.6 | 680.7 |
| NYISO | 1,918.1 | 1,800.1 | 1,921.6 | 1,351.0 | 1,074.0 | 1,504.2 | 9,568.9 |
| HUDS |  |  |  |  |  | 25.6 | 25.6 |
| LIND | 165.8 | 160.3 | 99.1 | 78.5 | 84.8 | 66.1 | 654.5 |
| NEPT | 270.9 | 245.9 | 239.2 | 247.1 | 102.5 | 167.8 | 1,273.4 |
| NYIS | 1,481.5 | 1,393.9 | 1,583.3 | 1,025.4 | 886.6 | 1,244.7 | 7,615.4 |
| OVEC | 0.1 | 0.0 | 0.0 | 1.1 | 16.4 | 7.8 | 25.3 |
| TVA | 46.0 | 30.0 | 15.6 | 12.5 | 39.7 | 48.3 | 192.0 |
| Total | 3,445.3 | 2,970.0 | 3,191.9 | 2,635.5 | 2,995.8 | 3,232.8 | 18,471.2 |

## 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.[17] 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

17 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.[18]

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.[19] 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.[20] 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 8-17 presents the interface pricing points used for the first six 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.[21]

In the Real-Time Energy Market, for the first six months of 2013, there were net scheduled exports at eleven of PJM's 17 interface pricing points eligible for real-time transactions.[22] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 70.4 percent of the total net exports: PJM/MISO with 52.8 percent, and PJM/NYIS with 17.6 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 34.1 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 71.4 percent of the total

18 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.

19 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed July 17, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

20 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 July 17, 2013)

21 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.

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

net imports: PJM/SouthIMP with 44.0 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 27.4 percent of the net import volume.

### Table 8‑4 Real‑time scheduled net interchange volume by interface pricing point (GWh): January through June, 2013

|  | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| HUDS |  |  |  |  |  | (25.6) | (25.6) |
| IMO | 592.6 | 395.0 | 556.4 | 547.2 | 668.7 | 584.3 | 3,344.1 |
| LINDENVFT | (165.2) | (149.8) | (91.6) | (64.9) | (77.0) | (55.8) | (604.5) |
| MISO | (1,015.3) | (686.3) | (699.3) | (709.9) | (1,444.8) | (1,513.8) | (6,069.4) |
| NEPTUNE | (270.9) | (245.9) | (239.2) | (247.1) | (102.5) | (167.8) | (1,273.4) |
| NORTHWEST | (3.6) | (3.3) | (5.9) | (5.0) | (5.5) | (2.7) | (26.0) |
| NYIS | (603.2) | (572.1) | (706.3) | 62.9 | 28.4 | (230.2) | (2,020.7) |
| OVEC | 798.2 | 713.5 | 585.0 | 542.8 | 712.0 | 908.3 | 4,259.8 |
| SOUTHIMP | 1,441.6 | 1,472.4 | 1,387.4 | 923.1 | 1,306.5 | 1,411.2 | 7,942.1 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 219.4 | 219.4 |
| DUKIMP | 107.2 | 105.3 | 83.8 | 46.7 | 110.6 | 129.7 | 583.3 |
| NCMPAIMP | 68.6 | 31.3 | 19.5 | 22.6 | 95.1 | 61.7 | 298.9 |
| SOUTHWEST | 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 | 6,840.6 |
| SOUTHEXP | (303.9) | (283.9) | (255.9) | (291.0) | (238.9) | (129.7) | (1,503.3) |
| CPLEEXP | (31.3) | (33.4) | (47.6) | (32.0) | (26.7) | (30.8) | (201.7) |
| DUKEXP | (27.1) | (45.2) | (0.9) | (32.9) | (11.8) | (29.9) | (147.7) |
| NCMPAEXP | 0.0 | (0.1) | 0.0 | (0.2) | 0.0 | (1.5) | (1.7) |
| SOUTHWEST | (4.5) | (5.7) | (3.0) | (11.7) | (3.6) | (4.4) | (32.8) |
| SOUTHEXP | (241.0) | (199.6) | (204.5) | (214.2) | (196.9) | (63.1) | (1,119.3) |
| Total | 470.4 | 639.5 | 530.6 | 757.9 | 846.7 | 778.1 | 4,023.3 |

### Table 8‑5 Real‑time scheduled gross import volume by interface pricing point (GWh): January through June, 2013

|  | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| HUDS |  |  |  |  |  | 0.0 | 0.0 |
| IMO | 594.6 | 403.2 | 562.5 | 549.8 | 669.9 | 584.7 | 3,364.7 |
| LINDENVFT | 0.6 | 10.4 | 7.5 | 13.5 | 7.8 | 10.2 | 50.1 |
| MISO | 204.4 | 196.3 | 309.1 | 277.5 | 215.9 | 74.6 | 1,277.8 |
| NEPTUNE | 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 |
| NYIS | 876.3 | 813.6 | 870.9 | 1,085.7 | 914.0 | 1,014.1 | 5,574.6 |
| OVEC | 798.3 | 713.5 | 585.1 | 543.8 | 728.4 | 916.1 | 4,285.2 |
| SOUTHIMP | 1,441.6 | 1,472.4 | 1,387.4 | 923.1 | 1,306.5 | 1,411.2 | 7,942.1 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 219.4 | 219.4 |
| DUKIMP | 107.2 | 105.3 | 83.8 | 46.7 | 110.6 | 129.7 | 583.3 |
| NCMPAIMP | 68.6 | 31.3 | 19.5 | 22.6 | 95.1 | 61.7 | 298.9 |
| SOUTHWEST | 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 | 6,840.6 |
| SOUTHEXP | 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 |
| DUKEXP | 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 |
| SOUTHWEST | 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 |
| Total | 3,915.7 | 3,609.5 | 3,722.4 | 3,393.4 | 3,842.5 | 4,010.9 | 22,494.5 |

**Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through June, 2013**

|  | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| HUDS |  |  |  |  |  | 25.6 | 25.6 |
| IMO | 2.0 | 8.2 | 6.1 | 2.6 | 1.3 | 0.4 | 20.6 |
| LINDENVFT | 165.8 | 160.3 | 99.1 | 78.5 | 84.8 | 66.1 | 654.5 |
| MISO | 1,219.7 | 882.6 | 1,008.4 | 987.4 | 1,660.7 | 1,588.4 | 7,347.2 |
| NEPTUNE | 270.9 | 245.9 | 239.2 | 247.1 | 102.5 | 167.8 | 1,273.4 |
| NORTHWEST | 3.6 | 3.3 | 5.9 | 5.0 | 5.5 | 2.7 | 26.0 |
| NYIS | 1,479.5 | 1,385.8 | 1,577.2 | 1,022.8 | 885.6 | 1,244.3 | 7,595.2 |
| OVEC | 0.1 | 0.0 | 0.0 | 1.1 | 16.4 | 7.8 | 25.3 |
| SOUTHIMP | 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 |
| DUKIMP | 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 |
| SOUTHWEST | 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 |
| SOUTHEXP | 303.9 | 283.9 | 255.9 | 291.0 | 238.9 | 129.7 | 1,503.3 |
| CPLEEXP | 31.3 | 33.4 | 47.6 | 32.0 | 26.7 | 30.8 | 201.7 |
| DUKEXP | 27.1 | 45.2 | 0.9 | 32.9 | 11.8 | 29.9 | 147.7 |
| NCMPAEXP | 0.0 | 0.1 | 0.0 | 0.2 | 0.0 | 1.5 | 1.7 |
| SOUTHWEST | 4.5 | 5.7 | 3.0 | 11.7 | 3.6 | 4.4 | 32.8 |
| SOUTHEXP | 241.0 | 199.6 | 204.5 | 214.2 | 196.9 | 63.1 | 1,119.3 |
| Total | 3,445.3 | 2,970.0 | 3,191.9 | 2,635.5 | 2,995.8 | 3,232.8 | 18,471.2 |

## 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.[23] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow unless they are also submitted in the Real-Time Energy Market. In the Day-Ahead Energy Market,

a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up-to congestion; and dispatchable.[24]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. In Table 8-7, Table 8-8 and Table 8-9, 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 8-7 through Table 8-9 show the Day-Ahead interchange totals at the individual interfaces. Net interchange in the Day-Ahead Market is shown by interface for the first six months of 2013 in Table 8-7, while gross imports and exports are shown in Table 8-8 and Table 8-9.

In the Day-Ahead Energy Market, for the first six months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.[25] The top three net exporting interfaces in the Real-Time Energy Market accounted for 78.5 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 31.7 percent, PJM/MidAmerican Energy Company (MEC) with 31.6 percent, and PJM/NEPT with 15.2 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS,

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23 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.

24 See the *2010 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for details.
25 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.

PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 48.1 percent of the total net PJM exports in the Day-Ahead Energy Market. The nine separate interfaces that connect PJM to MISO together represented 11.5 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 84.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 63.6 percent, PJM/DUK with 12.5 percent and PJM/Michigan Electric Coordinated Systems (MECS) with 8.6 percent of the net import volume.[26]

**Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through June, 2013**

|  | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| CPLE | (33.4) | (28.5) | (41.2) | (30.5) | (24.1) | 172.0 | 14.2 |
| CPLW | 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 | 579.5 |
| 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 | 248.5 |
| MEC | (483.0) | (435.7) | (477.7) | (423.0) | (484.7) | (462.9) | (2,767.0) |
| MISO | (242.1) | (52.6) | (48.7) | (34.3) | (324.7) | (302.2) | (1,004.7) |
| ALTE | (177.8) | (79.5) | (119.1) | (99.9) | (238.2) | (267.3) | (981.6) |
| ALTW | (7.6) | (2.5) | 0.0 | 0.0 | (2.5) | (35.8) | (48.3) |
| AMIL | 8.7 | 5.2 | 26.3 | 13.5 | (0.9) | (1.2) | 51.6 |
| CIN | 7.9 | 45.9 | 37.1 | 32.3 | 18.3 | 44.4 | 185.9 |
| CWLP | 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 | 25.5 |
| MECS | 23.4 | 45.8 | 102.9 | 93.1 | 97.9 | 36.9 | 400.2 |
| NIPS | (22.2) | (12.5) | (21.5) | (27.8) | (70.7) | 0.0 | (154.7) |
| WEC | (73.7) | (49.2) | (72.8) | (45.5) | (128.8) | (113.1) | (483.1) |
| NYISO | (833.6) | (874.4) | (944.3) | (459.5) | (386.6) | (707.5) | (4,205.9) |
| HUDS |  |  |  |  | (32.5) | (36.6) | (69.1) |
| LIND | (15.3) | (14.3) | (2.6) | 0.1 | 0.0 | 0.1 | (32.1) |
| NEPT | (278.5) | (255.2) | (248.7) | (253.1) | (101.5) | (193.7) | (1,330.7) |
| NYIS | (539.7) | (604.9) | (693.0) | (206.5) | (252.6) | (477.2) | (2,774.0) |
| OVEC | 561.5 | 494.4 | 408.0 | 324.6 | 522.8 | 644.8 | 2,956.0 |
| TVA | 32.7 | 3.6 | (3.6) | 41.2 | 92.4 | 18.6 | 185.0 |
| Total without Up-To Congestion | (898.1) | (790.9) | (987.2) | (494.9) | (494.1) | (509.7) | (4,174.9) |
| Up-To Congestion | (1,704.8) | (1,336.7) | (875.0) | (421.3) | (191.6) | (457.4) | (4,986.7) |
| Total | (2,602.8) | (2,127.7) | (1,862.2) | (916.1) | (685.7) | (967.1) | (9,161.6) |

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

|  | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| CPLE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 202.5 | 202.5 |
| CPLW | 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 | 579.5 |
| 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 | 248.5 |
| MEC | 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 | 1,032.5 |
| ALTE | 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 |
| AMIL | 8.7 | 5.2 | 26.3 | 13.5 | 3.9 | 1.9 | 59.6 |
| CIN | 21.5 | 64.2 | 58.4 | 77.7 | 61.9 | 52.0 | 335.7 |
| CWLP | 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 | 39.6 |
| MECS | 39.3 | 45.8 | 111.9 | 93.1 | 165.8 | 141.6 | 597.6 |
| NIPS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| WEC | 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 | 4,190.9 |
| HUDS |  |  |  |  | 0.0 | 0.0 | 0.0 |
| LIND | 0.1 | 9.3 | 2.9 | 0.1 | 0.0 | 0.1 | 12.4 |
| NEPT | 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 | 4,178.5 |
| OVEC | 561.5 | 494.4 | 408.0 | 324.6 | 522.8 | 644.8 | 2,956.0 |
| TVA | 41.7 | 13.6 | 3.6 | 42.7 | 102.8 | 21.5 | 225.9 |
| Total without Up-To Congestion | 1,540.9 | 1,409.5 | 1,483.5 | 1,442.6 | 1,606.8 | 1,952.4 | 9,435.8 |
| Up-To Congestion | 4,637.9 | 3,481.0 | 4,226.5 | 4,728.9 | 4,890.0 | 4,135.3 | 26,099.5 |
| Total | 6,178.8 | 4,890.5 | 5,710.0 | 6,171.5 | 6,496.8 | 6,087.8 | 35,535.3 |

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26 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 8-9 Day-Ahead scheduled gross export volume by interface (GWh): January through June, 2013**

| | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| CPLE | 33.4 | 28.5 | 41.2 | 30.5 | 24.1 | 30.5 | 188.3 |
| CPLW | 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 |
| 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 |
| MEC | 483.0 | 435.7 | 477.7 | 423.0 | 484.7 | 462.9 | 2,767.0 |
| MISO | 317.3 | 167.9 | 245.4 | 218.6 | 556.4 | 531.6 | 2,037.1 |
| ALTE | 177.8 | 79.5 | 119.1 | 99.9 | 238.2 | 267.3 | 981.6 |
| ALTW | 7.6 | 2.5 | 0.0 | 0.0 | 2.5 | 35.8 | 48.3 |
| AMIL | 0.0 | 0.0 | 0.0 | 0.0 | 4.8 | 3.2 | 8.0 |
| CIN | 13.7 | 18.3 | 21.3 | 45.5 | 43.5 | 7.6 | 149.8 |
| CWLP | 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 | 14.0 |
| MECS | 15.9 | 0.0 | 9.1 | 0.0 | 67.9 | 104.7 | 197.5 |
| NIPS | 22.2 | 12.5 | 21.5 | 27.8 | 70.7 | 0.0 | 154.7 |
| WEC | 73.7 | 49.2 | 72.8 | 45.5 | 128.8 | 113.1 | 483.1 |
| NYISO | 1,559.8 | 1,524.8 | 1,662.1 | 1,227.8 | 988.2 | 1,434.2 | 8,396.8 |
| HUDS | | | | | 32.5 | 36.6 | 69.1 |
| LIND | 15.4 | 23.6 | 5.5 | 0.0 | 0.0 | 0.0 | 44.5 |
| NEPT | 278.5 | 255.2 | 248.7 | 253.1 | 101.5 | 193.7 | 1,330.7 |
| NYIS | 1,265.9 | 1,246.0 | 1,407.8 | 974.7 | 854.2 | 1,203.9 | 6,952.5 |
| OVEC | 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 | 40.9 |
| Total without Up-To Congestion | 2,439.0 | 2,200.5 | 2,470.7 | 1,937.5 | 2,100.9 | 2,462.2 | 13,610.7 |
| Up-To Congestion | 6,342.6 | 4,817.7 | 5,101.5 | 5,150.2 | 5,081.6 | 4,592.7 | 31,086.3 |
| Total | 8,781.6 | 7,018.2 | 7,572.2 | 7,087.7 | 7,182.4 | 7,054.9 | 44,697.0 |

## Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-15 show the Day-Ahead Market interchange totals at the individual interface pricing points. In the first six months of 2013, up-to congestion transactions accounted for 73.4 percent of all scheduled import MW transactions, 69.5 percent of all scheduled export MW transactions and 54.4 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 six months of 2013 in Table 8-10. Up-to congestion transactions by interface pricing point for the first six

months of 2013 are shown in Table 8-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Market are shown in Table 8-12 and Table 8-14, while gross import up-to congestion transactions are show in Table 8-13 and gross export up-to congestion transactions are shown in Table 8-15.

In the Day-Ahead Energy Market, for the first six months of 2013, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead.[27] The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 63.7 percent of the total net exports: PJM/SouthEXP with 24.2 percent, PJM/NIPSCO with 21.8 percent and PJM/Southwest with 17.7 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 26.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interface pricing points had net imports, with three importing interface pricing points accounting for 75.1 percent of the total net imports: PJM/SouthIMP with 33.9 percent, PJM/Ohio Valley Electric Corporation (OVEC) with 21.7 percent and PJM/Southeast with 19.5 percent of the net import volume.[28]

In the Day-Ahead Market, for the first six months of 2013, up-to congestion transactions had net exports at five of PJM's 19 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points for up-to congestion transactions accounted for 57.2 percent of the total net up-to congestion exports: PJM/SouthEXP with 29.2 percent and PJM/NIPSCO with 28.0 percent of the net export up-to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 7.4 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 7.4 percent). The PJM/NYIS and the PJM/LINDEN interface pricing points had net imports in the Day-Ahead Energy Market and the PJM/HUDS interface pricing point had a net interchange of zero. Seven PJM interface pricing points had net up-to congestion imports, with two importing

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27 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).
28 In the Day-Ahead Market, one PJM interface pricing points had a net interchange of zero (PJM/DUKEXP).

interface pricing points accounting for 51.8 percent of the total net up-to congestion imports: PJM/MISO with 32.1 percent and PJM/Northwest with 19.6 percent of the net import volume.[29]

### Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): January through June, 2013

| | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| HUDS | | | | | (32.5) | (36.6) | (69.1) |
| IMO | 27.4 | 235.1 | 206.5 | 104.5 | 100.1 | 37.8 | 711.3 |
| LINDENVFT | 102.2 | 14.5 | (14.6) | (16.8) | (68.7) | (13.6) | 3.0 |
| MISO | 192.7 | 130.5 | 453.0 | 228.8 | (434.9) | (207.4) | 362.8 |
| NEPTUNE | (335.1) | (381.7) | (398.9) | (473.6) | (341.6) | (302.0) | (2,232.9) |
| NIPSCO | (927.2) | (757.5) | (743.5) | (591.9) | (121.5) | (269.9) | (3,411.6) |
| NORTHWEST | (744.5) | (810.7) | (646.6) | 199.5 | 520.7 | 128.3 | (1,353.3) |
| NYIS | (662.2) | (576.6) | (506.4) | 208.5 | 10.8 | (312.0) | (1,837.9) |
| OVEC | 254.6 | 210.5 | 438.4 | 269.4 | 92.5 | 142.3 | 1,407.7 |
| SOUTHIMP | 1,255.6 | 902.5 | 877.1 | 965.4 | 1,108.3 | 1,236.1 | 6,345.2 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 202.5 | 202.5 |
| DUKIMP | 22.5 | 22.0 | 9.0 | 7.0 | 17.5 | 46.8 | 124.8 |
| NCMPAIMP | 18.3 | 15.4 | 14.9 | 19.1 | 84.6 | 53.9 | 206.1 |
| SOUTHEAST | 488.4 | 326.9 | 366.3 | 268.4 | 188.8 | 182.9 | 1,821.8 |
| SOUTHWEST | 283.6 | 231.0 | 184.8 | 321.0 | 394.2 | 376.6 | 1,791.2 |
| SOUTHIMP | 442.8 | 307.4 | 302.0 | 349.9 | 423.2 | 373.5 | 2,198.8 |
| SOUTHEXP | (1,766.4) | (1,094.4) | (1,527.3) | (1,809.8) | (1,518.9) | (1,370.0) | (9,086.8) |
| CPLEEXP | (32.4) | (27.8) | (40.7) | (29.6) | (22.8) | (29.5) | (182.7) |
| DUKEXP | 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) | (5.6) |
| SOUTHEAST | (49.3) | (28.8) | (26.5) | (123.4) | (213.1) | (118.9) | (560.0) |
| SOUTHWEST | (912.1) | (535.5) | (800.2) | (1,017.5) | (653.5) | (638.6) | (4,557.3) |
| SOUTHEXP | (771.5) | (501.6) | (659.5) | (638.4) | (628.2) | (582.0) | (3,781.2) |
| Total | (2,602.8) | (2,127.7) | (1,862.2) | (916.1) | (685.7) | (967.1) | (9,161.6) |

### Table 8-11 Up-to Congestion scheduled net interchange volume by interface pricing point (GWh): January through June, 2013

| | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| HUDS | | | | | 0.0 | 0.0 | 0.0 |
| IMO | (11.9) | 189.4 | 94.5 | 18.0 | (62.6) | (92.8) | 134.6 |
| LINDENVFT | 117.5 | 28.8 | (12.0) | (16.9) | (68.7) | (13.7) | 35.0 |
| MISO | 500.7 | 288.8 | 660.8 | 422.2 | 117.7 | 323.4 | 2,313.5 |
| NEPTUNE | (56.5) | (126.5) | (150.2) | (220.6) | (240.1) | (108.3) | (902.1) |
| NIPSCO | (927.2) | (757.5) | (743.5) | (591.9) | (121.5) | (269.9) | (3,411.6) |
| NORTHWEST | (261.6) | (375.0) | (168.9) | 622.5 | 1,004.7 | 591.2 | 1,413.0 |
| NYIS | (121.9) | 25.3 | 185.7 | 415.0 | 264.0 | 165.2 | 933.3 |
| OVEC | (306.9) | (281.8) | 31.4 | (55.2) | (430.3) | (502.5) | (1,545.3) |
| SOUTHIMP | 1,050.5 | 694.0 | 668.9 | 727.3 | 792.5 | 786.7 | 4,719.8 |
| CPLEIMP | 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 |
| NCMPAIMP | 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 | 1,819.9 |
| SOUTHWEST | 283.6 | 231.0 | 184.8 | 321.0 | 394.2 | 376.6 | 1,791.2 |
| SOUTHIMP | 278.5 | 136.1 | 117.7 | 137.9 | 209.4 | 229.0 | 1,108.7 |
| SOUTHEXP | (1,687.4) | (1,022.2) | (1,441.8) | (1,741.8) | (1,447.2) | (1,336.7) | (8,677.1) |
| CPLEEXP | 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 |
| NCMPAEXP | 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) | (560.0) |
| SOUTHWEST | (912.1) | (535.5) | (800.2) | (1,017.5) | (653.5) | (638.6) | (4,557.3) |
| SOUTHEXP | (725.9) | (457.9) | (615.1) | (600.9) | (580.6) | (579.2) | (3,559.8) |
| Total Interfaces | (1,704.8) | (1,336.7) | (875.0) | (421.3) | (191.6) | (457.4) | (4,986.7) |
| INTERNAL | 22,906.0 | 23,311.1 | 27,439.6 | 32,152.2 | 34,779.0 | 34,935.1 | 175,523.0 |
| Total | 21,201.2 | 21,974.3 | 26,564.6 | 31,731.0 | 34,587.4 | 34,477.8 | 170,536.3 |

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[29] In the Day-Ahead Market, seven PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP, PJM/NCMPAEXP and PJM/HUDS) had a net interchange of zero.

**Table 8-12 Day-Ahead scheduled gross import volume by interface pricing point (GWh): January through June, 2013**

| | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| HUDS | | | | | 0.0 | 0.0 | 0.0 |
| IMO | 268.0 | 322.5 | 310.8 | 285.5 | 376.4 | 341.5 | 1,904.8 |
| LINDENVFT | 292.4 | 210.2 | 188.5 | 130.0 | 145.1 | 119.8 | 1,085.9 |
| MISO | 719.6 | 516.2 | 809.8 | 770.8 | 470.0 | 591.0 | 3,877.3 |
| NEPTUNE | 127.2 | 32.2 | 11.5 | 17.2 | 10.8 | 10.1 | 209.0 |
| NIPSCO | 35.0 | 17.1 | 15.0 | 65.2 | 180.8 | 135.0 | 448.3 |
| NORTHWEST | 287.9 | 214.8 | 229.9 | 818.0 | 1,184.5 | 728.3 | 3,463.3 |
| NYIS | 1,097.0 | 1,031.5 | 1,130.2 | 1,260.6 | 991.5 | 1,046.5 | 6,557.3 |
| OVEC | 2,096.0 | 1,643.5 | 2,137.2 | 1,858.8 | 2,029.3 | 1,879.4 | 11,644.3 |
| SOUTHIMP | 1,255.6 | 902.5 | 877.1 | 965.4 | 1,108.3 | 1,236.1 | 6,345.2 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 202.5 | 202.5 |
| DUKIMP | 22.5 | 22.0 | 9.0 | 7.0 | 17.5 | 46.8 | 124.8 |
| NCMPAIMP | 18.3 | 15.4 | 14.9 | 19.1 | 84.6 | 53.9 | 206.1 |
| SOUTHEAST | 488.4 | 326.9 | 366.3 | 268.4 | 188.8 | 182.9 | 1,821.8 |
| SOUTHWEST | 283.6 | 231.0 | 184.8 | 321.0 | 394.2 | 376.6 | 1,791.2 |
| SOUTHIMP | 442.8 | 307.4 | 302.0 | 349.9 | 423.2 | 373.5 | 2,198.8 |
| SOUTHEXP | 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 |
| DUKEXP | 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 |
| SOUTHEAST | 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 |
| SOUTHEXP | 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 | 35,535.3 |

**Table 8-13 Up-to Congestion scheduled gross import volume by interface pricing point (GWh): January through June, 2013**

| | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| HUDS | | | | | 0.0 | 0.0 | 0.0 |
| IMO | 228.7 | 276.6 | 198.9 | 199.1 | 213.8 | 210.9 | 1,328.0 |
| LINDENVFT | 292.4 | 200.9 | 185.5 | 129.9 | 145.1 | 119.8 | 1,073.5 |
| MISO | 710.9 | 505.8 | 772.2 | 745.5 | 466.1 | 590.2 | 3,790.6 |
| NEPTUNE | 127.2 | 32.2 | 11.5 | 17.2 | 10.8 | 10.1 | 209.0 |
| NIPSCO | 35.0 | 17.1 | 15.0 | 65.2 | 180.8 | 135.0 | 448.3 |
| NORTHWEST | 287.9 | 214.8 | 229.9 | 818.0 | 1,184.5 | 728.3 | 3,463.3 |
| NYIS | 370.9 | 388.3 | 414.4 | 492.4 | 389.9 | 319.8 | 2,375.7 |
| OVEC | 1,534.5 | 1,151.2 | 1,730.2 | 1,534.2 | 1,506.5 | 1,234.6 | 8,691.4 |
| SOUTHIMP | 1,050.5 | 694.0 | 668.9 | 727.3 | 792.5 | 786.7 | 4,719.8 |
| CPLEIMP | 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 |
| NCMPAIMP | 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 | 1,819.9 |
| SOUTHWEST | 283.6 | 231.0 | 184.8 | 321.0 | 394.2 | 376.6 | 1,791.2 |
| SOUTHIMP | 278.5 | 136.1 | 117.7 | 137.9 | 209.4 | 229.0 | 1,108.7 |
| SOUTHEXP | 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 |
| DUKEXP | 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 |
| SOUTHEAST | 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 |
| SOUTHEXP | 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 | 26,099.5 |

Table 8-14 Day-Ahead scheduled gross export volume by interface pricing point (GWh): January through June, 2013

| | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| HUDS | | | | | 32.5 | 36.6 | 69.1 |
| IMO | 240.6 | 87.4 | 104.4 | 181.1 | 276.4 | 303.7 | 1,193.5 |
| LINDENVFT | 190.2 | 195.7 | 203.1 | 146.7 | 213.8 | 133.4 | 1,083.0 |
| MISO | 526.9 | 385.6 | 356.8 | 541.9 | 904.9 | 798.4 | 3,514.5 |
| NEPTUNE | 462.2 | 413.9 | 410.4 | 490.9 | 352.4 | 312.1 | 2,441.8 |
| NIPSCO | 962.3 | 774.6 | 758.5 | 657.2 | 302.4 | 405.0 | 3,859.9 |
| NORTHWEST | 1,032.4 | 1,025.5 | 876.4 | 618.5 | 663.8 | 600.0 | 4,816.5 |
| NYIS | 1,759.2 | 1,608.1 | 1,636.5 | 1,052.1 | 980.7 | 1,358.5 | 8,395.2 |
| OVEC | 1,841.4 | 1,433.0 | 1,698.8 | 1,589.5 | 1,936.8 | 1,737.2 | 10,236.6 |
| SOUTHIMP | 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 |
| DUKIMP | 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 |
| SOUTHEAST | 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 |
| SOUTHIMP | 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 | 9,086.8 |
| CPLEEXP | 32.4 | 27.8 | 40.7 | 29.6 | 22.8 | 29.5 | 182.7 |
| DUKEXP | 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 | 5.6 |
| SOUTHEAST | 49.3 | 28.8 | 26.5 | 123.4 | 213.1 | 118.9 | 560.0 |
| SOUTHWEST | 912.1 | 535.5 | 800.2 | 1,017.5 | 653.5 | 638.6 | 4,557.3 |
| SOUTHEXP | 771.5 | 501.6 | 659.5 | 638.4 | 628.2 | 582.0 | 3,781.2 |
| Total | 8,781.6 | 7,018.2 | 7,572.2 | 7,087.7 | 7,182.4 | 7,054.9 | 44,697.0 |

Table 8-15 Up-to Congestion scheduled gross export volume by interface pricing point (GWh): January through June, 2013

| | Jan | Feb | Mar | Apr | May | Jun | Total |
|---|---|---|---|---|---|---|---|
| HUDS | | | | | 0.0 | 0.0 | 0.0 |
| IMO | 240.6 | 87.3 | 104.4 | 181.1 | 276.4 | 303.7 | 1,193.4 |
| LINDENVFT | 174.8 | 172.1 | 197.6 | 146.7 | 213.8 | 133.4 | 1,038.5 |
| MISO | 210.2 | 217.0 | 111.4 | 323.3 | 348.4 | 266.7 | 1,477.1 |
| NEPTUNE | 183.7 | 158.7 | 161.7 | 237.8 | 250.9 | 118.4 | 1,111.1 |
| NIPSCO | 962.3 | 774.6 | 758.5 | 657.2 | 302.4 | 405.0 | 3,859.9 |
| NORTHWEST | 549.4 | 589.8 | 398.7 | 195.5 | 179.8 | 137.1 | 2,050.3 |
| NYIS | 492.8 | 362.9 | 228.7 | 77.4 | 126.0 | 154.6 | 1,442.4 |
| OVEC | 1,841.4 | 1,433.0 | 1,698.8 | 1,589.5 | 1,936.8 | 1,737.2 | 10,236.6 |
| SOUTHIMP | 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 |
| DUKIMP | 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 |
| SOUTHEAST | 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 |
| SOUTHIMP | 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 | 8,677.1 |
| CPLEEXP | 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 |
| NCMPAEXP | 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 | 560.0 |
| SOUTHWEST | 912.1 | 535.5 | 800.2 | 1,017.5 | 653.5 | 638.6 | 4,557.3 |
| SOUTHEXP | 725.9 | 457.9 | 615.1 | 600.9 | 580.6 | 579.2 | 3,559.8 |
| Total | 6,342.6 | 4,817.7 | 5,101.5 | 5,150.2 | 5,081.6 | 4,592.7 | 31,086.3 |

## Table 8-16 Active interfaces: January through June, 2013[30,31,32]

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

## Figure 8-3 PJM's footprint and its external interfaces
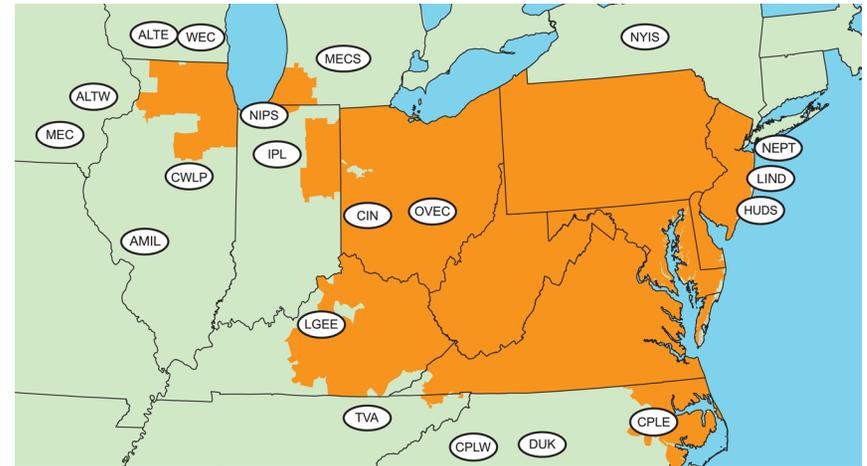


## Table 8-17 Active pricing points: January through June, 2013[33]

|             | Jan    | Feb    | Mar    | Apr    | May    | Jun    |
|-------------|--------|--------|--------|--------|--------|--------|
| CPLEEXP     | Active | Active | Active | Active | Active | Active |
| CPLEIMP     | Active | Active | Active | Active | Active | Active |
| DUKEXP      | Active | Active | Active | Active | Active | Active |
| DUKIMP      | Active | Active | Active | Active | Active | Active |
| HUDSONTP    |        |        |        |        |        | Active |
| LIND        | Active | Active | Active | Active | Active | Active |
| MISO        | Active | Active | Active | Active | Active | Active |
| NCMPAEXP    | Active | Active | Active | Active | Active | Active |
| NCMPAIMP    | Active | Active | Active | Active | Active | Active |
| NEPT        | Active | Active | Active | Active | Active | Active |
| NIPSCO      | Active | Active | Active | Active | Active | Active |
| Northwest   | Active | Active | Active | Active | Active | Active |
| NYIS        | Active | Active | Active | Active | Active | Active |
| Ontario IESO| Active | Active | Active | Active | Active | Active |
| OVEC        | Active | Active | Active | Active | Active | Active |
| Southeast   | Active | Active | Active | Active | Active | Active |
| SOUTHEXP    | Active | Active | Active | Active | Active | Active |
| SOUTHIMP    | Active | Active | Active | Active | Active | Active |
| Southwest   | Active | Active | Active | Active | Active | Active |

30 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.

31 On June 1, 2013, East Kentucky Power Cooperative (EKPC) integrated with PJM, resulting in the elimination of the EKPC Interface.

32 On June 3, 2013, the Hudson DC Line began commercial operation resulting in the addition of the HUDS Interface.

33 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.[34]

For the first six months of 2013, net scheduled interchange was 2,989 GWh and net actual interchange was 3,058 GWh, a difference of 69 GWh. For the first six months of 2012, net scheduled interchange was 1,666 GWh and net actual interchange was 1,480 GWh, a difference of 185 GWh.[35] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[36]

**Table 8-18 Net scheduled and actual PJM flows by interface (GWh): January through June, 2013[37]**

|  | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|
| CPLE | 3,718 | (45) | 3,763 |
| CPLW | (703) | – | (703) |
| DUK | 444 | 1,043 | (599) |
| EKPC | 957 | (569) | 1,526 |
| LGEE | 784 | 1,496 | (713) |
| MEC | (922) | (2,424) | 1,502 |
| MISO | (6,152) | 1,983 | (8,134) |
| ALTE | (3,004) | (1,842) | (1,162) |
| ALTW | (1,097) | (86) | (1,011) |
| AMIL | 5,640 | 849 | 4,791 |
| CIN | (2,717) | 1,537 | (4,255) |
| CWLP | (99) | 0 | (99) |
| IPL | 303 | 166 | 137 |
| MECS | (5,657) | 2,198 | (7,855) |
| NIPS | (2,360) | (160) | (2,201) |
| WEC | 2,840 | (681) | 3,521 |
| NYISO | (4,349) | (4,421) | 72 |
| HUDS | (26) | (26) | 0 |
| LIND | (604) | (604) | 0 |
| NEPT | (1,273) | (1,273) | 0 |
| NYIS | (2,445) | (2,518) | 72 |
| OVEC | 6,389 | 4,260 | 2,129 |
| TVA | 2,892 | 1,666 | 1,226 |
| Total | 3,058 | 2,989 | 69 |

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.[38] 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

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34 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.
35 The "Net Scheduled" values shown in Table 8-18 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. As a result, the net interchange in this table does not match the interchange values shown in Table 8-1 through Table 8-6.
36 See PJM. "M-12: Balancing Operations", Revision 23 (November 16, 2011).

37 There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM*.
38 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 8-19 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 (7,136 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 5,561 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 8-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through June, 2013[39]**

|  | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|
| HUDSONTP | (26) | (26) | 0 |
| IMO | 0 | 3,344 | (3,344) |
| LINDENVFT | (604) | (604) | 0 |
| MISO | (5,195) | (6,114) | 919 |
| NEPTUNE | (1,273) | (1,273) | 0 |
| NORTHWEST | (922) | (22) | (900) |
| NYIS | (2,445) | (2,137) | (309) |
| OVEC | 6,389 | 4,260 | 2,129 |
| SOUTHIMP | 7,136 | 7,065 | 71 |
|   CPLEIMP | 0 | 219 | (219) |
|   DUKIMP | 0 | 583 | (583) |
|   NCMPAIMP | 0 | 299 | (299) |
|   SOUTHWEST | 0 | 0 | 0 |
|   SOUTHIMP | 7,136 | 5,963 | 1,173 |
| SOUTHEXP | 0 | (1,503) | 1,503 |
|   CPLEEXP | 0 | (202) | 202 |
|   DUKEXP | 0 | (148) | 148 |
|   NCMPAEXP | 0 | (2) | 2 |
|   SOUTHWEST | 0 | (33) | 33 |
|   SOUTHEXP | 0 | (1,119) | 1,119 |
| Total | 3,058 | 2,989 | 69 |

Table 8-20 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.

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39 There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM.*

Table 8-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through June, 2013[40]

| | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|
| HUDSONTP | (26) | (26) | 0 |
| LINDENVFT | (604) | (604) | 0 |
| MISO | (5,195) | (2,759) | (2,436) |
| NEPTUNE | (1,273) | (1,273) | 0 |
| NORTHWEST | (922) | (22) | (900) |
| NYIS | (2,445) | (2,148) | (297) |
| OVEC | 6,389 | 4,260 | 2,129 |
| SOUTHIMP | 7,136 | 7,065 | 71 |
| CPLEIMP | 0 | 219 | (219) |
| DUKIMP | 0 | 583 | (583) |
| NCMPAIMP | 0 | 299 | (299) |
| SOUTHWEST | 0 | 0 | 0 |
| SOUTHIMP | 7,136 | 5,963 | 1,173 |
| SOUTHEXP | 0 | (1,503) | 1,503 |
| CPLEEXP | 0 | (202) | 202 |
| DUKEXP | 0 | (148) | 148 |
| NCMPAEXP | 0 | (2) | 2 |
| SOUTHWEST | 0 | (33) | 33 |
| SOUTHEXP | 0 | (1,119) | 1,119 |
| Total | 3,058 | 2,989 | 69 |

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 8-21 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 8-21 shows that for the first six 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 (1,074 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 (817 GWh).

Table 8-22 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 8-22 shows that for the first six 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 (1,837 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 (11 GWh).

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[40] There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM*.

### Table 8-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through June, 2013[41]

| Interface | Interface Pricing Point | Actual | Net Scheduled | Difference (GWh) | Interface | Interface Pricing Point | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| ALTE | | (3,004) | (1,842) | (1,162) | IPL | | 303 | 166 | 137 |
| | MISO | (3,004) | (1,841) | (1,163) | | IMO | 0 | 445 | (445) |
| | NORTHWEST | 0 | (1) | 1 | | MISO | 303 | (445) | 748 |
| | SOUTHIMP | 0 | 1 | (1) | | SOUTHIMP | 0 | 167 | (167) |
| ALTW | | (1,097) | (86) | (1,011) | LGEE | | 784 | 1,496 | (713) |
| | MISO | (1,097) | (85) | (1,012) | | SOUTHEXP | 0 | (23) | 23 |
| AMIL | | 5,640 | 849 | 4,791 | | SOUTHIMP | 784 | 1,520 | (736) |
| | MISO | 5,640 | 858 | 4,782 | LIND | | (604) | (604) | 0 |
| | NORTHWEST | 0 | (1) | 1 | | LINDENVFT | (604) | (604) | 0 |
| | SOUTHIMP | 0 | 25 | (25) | MEC | | (922) | (2,424) | 1,502 |
| | SOUTHWEST | 0 | (33) | 33 | | MISO | 0 | (2,774) | 2,774 |
| CIN | | (2,717) | 1,537 | (4,255) | | NORTHWEST | (922) | 4 | (926) |
| | IMO | 0 | 1,074 | (1,074) | | SOUTHIMP | 0 | 346 | (346) |
| | MISO | (2,717) | (817) | (1,900) | MECS | | (5,657) | 2,198 | (7,855) |
| | NORTHWEST | 0 | (23) | 23 | | IMO | 0 | 1,837 | (1,837) |
| | NYIS | 0 | 370 | (370) | | MISO | (5,657) | (304) | (5,353) |
| | SOUTHIMP | 0 | 934 | (934) | | SOUTHIMP | 0 | 665 | (665) |
| CPLE | | 3,718 | (45) | 3,763 | NEPT | | (1,273) | (1,273) | 0 |
| | CPLEEXP | 0 | (202) | 202 | | NEPTUNE | (1,273) | (1,273) | 0 |
| | CPLEIMP | 0 | 219 | (219) | NIPS | | (2,360) | (160) | (2,201) |
| | SOUTHEXP | 0 | (10) | 10 | | MISO | (2,360) | (160) | (2,201) |
| | SOUTHIMP | 3,718 | (52) | 3,771 | NYIS | | (2,445) | (2,518) | 72 |
| CPLW | | (703) | 0 | (703) | | IMO | 0 | (11) | 11 |
| | SOUTHIMP | (703) | 0 | (703) | | NYIS | (2,445) | (2,506) | 61 |
| CWLP | | (99) | 0 | (99) | OVEC | | 6,389 | 4,260 | 2,129 |
| | MISO | (99) | 0 | (99) | | OVEC | 6,389 | 4,260 | 2,129 |
| DUK | | 444 | 1,043 | (599) | TVA | | 2,892 | 1,666 | 1,226 |
| | DUKEXP | 0 | (148) | 148 | | SOUTHEXP | 0 | (192) | 192 |
| | DUKIMP | 0 | 583 | (583) | | SOUTHIMP | 2,892 | 1,858 | 1,034 |
| | NCMPAEXP | 0 | (2) | 2 | WEC | | 2,840 | (681) | 3,521 |
| | NCMPAIMP | 0 | 299 | (299) | | MISO | 2,840 | (681) | 3,521 |
| | SOUTHEXP | 0 | (103) | 103 | HUDS | | (26) | (26) | 0 |
| | SOUTHIMP | 444 | 414 | 30 | | HUDSONTP | (26) | (26) | 0 |
| EKPC | | 957 | (569) | 1,526 | Total | | 3,058 | 2,989 | 69 |
| | MISO | 957 | 134 | 822 | | | | | |
| | SOUTHEXP | 0 | (790) | 790 | | | | | |
| | SOUTHIMP | 0 | 86 | (86) | | | | | |

41 There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM*.

Table 8-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through June, 2013[42]

| Interface Pricing Point | Interface | Actual | Net Scheduled | Difference (GWh) | Interface Pricing Point | Interface | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| CPLEEXP | | 0 | (202) | 202 | NORTHWEST | | (922) | (22) | (900) |
| | CPLE | 0 | (202) | 202 | | ALTE | 0 | (1) | 1 |
| CPLEIMP | | 0 | 219 | (219) | | ALTW | 0 | (0) | 0 |
| | CPLE | 0 | 219 | (219) | | AMIL | 0 | (1) | 1 |
| DUKEXP | | 0 | (148) | 148 | | CIN | 0 | (23) | 23 |
| | DUK | 0 | (148) | 148 | | MEC | (922) | 4 | (926) |
| DUKIMP | | 0 | 583 | (583) | | TVA | 0 | (0) | 0 |
| | DUK | 0 | 583 | (583) | NYIS | | (2,445) | (2,137) | (309) |
| IMO | | 0 | 3,344 | (3,344) | | CIN | 0 | 370 | (370) |
| | ALTE | 0 | 0 | (0) | | NYIS | (2,445) | (2,506) | 61 |
| | CIN | 0 | 1,074 | (1,074) | OVEC | | 6,389 | 4,260 | 2,129 |
| | IPL | 0 | 445 | (445) | | OVEC | 6,389 | 4,260 | 2,129 |
| | MECS | 0 | 1,837 | (1,837) | SOUTHEXP | | 0 | (1,119) | 1,119 |
| | NIPS | 0 | 0 | (0) | | CIN | 0 | (0) | 0 |
| | NYIS | 0 | (11) | 11 | | CPLE | 0 | (10) | 10 |
| LINDENVFT | | (604) | (604) | 0 | | DUK | 0 | (103) | 103 |
| | LIND | (604) | (604) | 0 | | EKPC | 0 | (790) | 790 |
| MISO | | (5,195) | (6,114) | 919 | | IPL | 0 | (0) | 0 |
| | ALTE | (3,004) | (1,841) | (1,163) | | LGEE | 0 | (23) | 23 |
| | ALTW | (1,097) | (85) | (1,012) | | TVA | 0 | (192) | 192 |
| | AMIL | 5,640 | 858 | 4,782 | SOUTHIMP | | 7,136 | 5,963 | 1,173 |
| | CIN | (2,717) | (817) | (1,900) | | ALTE | 0 | 1 | (1) |
| | CWLP | (99) | 0 | (99) | | AMIL | 0 | 25 | (25) |
| | EKPC | 957 | 134 | 822 | | CIN | 0 | 934 | (934) |
| | IPL | 303 | (445) | 748 | | CPLE | 3,718 | (52) | 3,771 |
| | MEC | 0 | (2,774) | 2,774 | | CPLW | (703) | 0 | (703) |
| | MECS | (5,657) | (304) | (5,353) | | DUK | 444 | 414 | 30 |
| | NIPS | (2,360) | (160) | (2,201) | | EKPC | 0 | 86 | (86) |
| | WEC | 2,840 | (681) | 3,521 | | IPL | 0 | 167 | (167) |
| NCMPAEXP | | 0 | (2) | 2 | | LGEE | 784 | 1,520 | (736) |
| | DUK | 0 | (2) | 2 | | MEC | 0 | 346 | (346) |
| NCMPAIMP | | 0 | 299 | (299) | | MECS | 0 | 665 | (665) |
| | DUK | 0 | 299 | (299) | | TVA | 2,892 | 1,858 | 1,034 |
| NEPTUNE | | (1,273) | (1,273) | 0 | SOUTHWEST | | 0 | (33) | 33 |
| | NEPT | (1,273) | (1,273) | 0 | | AMIL | 0 | (33) | 33 |
| | | | | | HUDSONTP | | (26) | (26) | 0 |
| | | | | | | HUDS | (26) | (26) | 0 |
| | | | | | Total | | 3,058 | 2,989 | 69 |

42 There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM*.

## 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[43] 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.[44]

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

In the first six months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first six months of 2013, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $30.91 while the MISO LMP at the border was $30.22, a difference of $0.69. While the average hourly LMP difference at the PJM/MISO border was only $0.69, the average of the absolute values of the hourly differences was $8.75. The average hourly flow during the first six months of 2013 was -1,325 MW. (The negative sign means that the flow was an export from PJM to MISO, which is inconsistent with the fact that the average MISO price was lower than the average PJM price.) The direction of flow was

consistent with price differentials in only 46.5 percent of hours in the first six months of 2013. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $11.23. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $6.97. In the first six 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 $11.04. 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 $13.27. 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 $12.09. 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 $6.15.

In the first six months of 2013, the day-ahead PJM average hourly LMP at the PJM/MISO border was $30.85 while the MISO LMP at the border was $31.34, a difference of $0.49.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-4). 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 8-6).

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43 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed July 17, 2013). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.
44 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010). (Accessed July 17, 2013)

Figure 8-4 Real-time and day-ahead daily hourly average price difference
(MISO Interface minus PJM/MISO): January through June, 2013
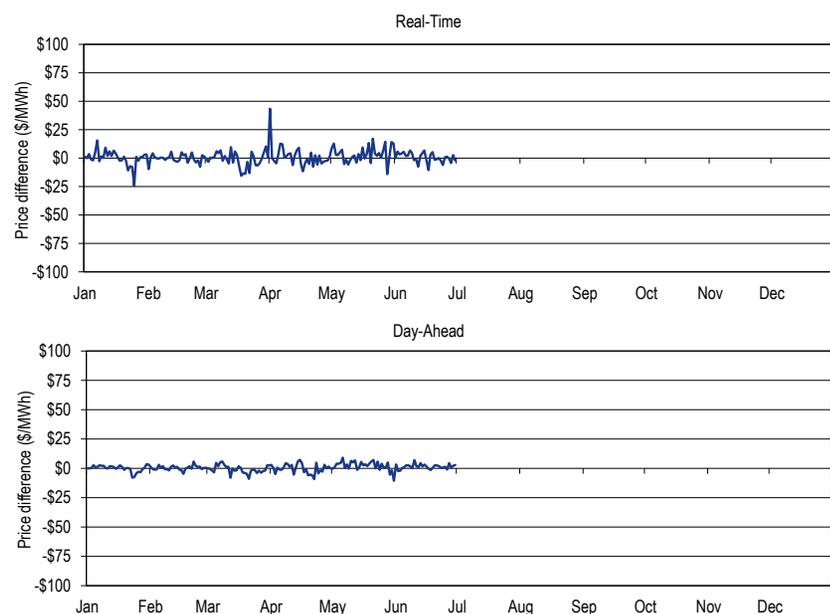


### Distribution of Economic and Uneconomic Hourly Flows at the PJM/MISO Interface

During the first six months of 2013, the direction of hourly energy flows was consistent with PJM and MISO Interface Price differentials in 2,019 hours (46.5 percent of all hours), and was inconsistent with price differentials in 2,324 hours (53.5 percent of all hours). Table 8-23 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 2,324 hours where flows were uneconomic, 2,017 of those hours (86.8 percent) had a price difference greater than or equal to $1.00 and 859 of all uneconomic hours (37.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $272.26. Of the 2,019 hours where flows were economic, 1,760 of those hours (87.2

percent) had a price difference greater than or equal to $1.00 and 1,081 of all economic hours (53.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $887.50.

Table 8-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through June, 2013

| Price Difference Range (Greater Than or Equal To) | Uneconomic Hours | Percent of Total Hours | Economic Hours | Percent of Total Hours |
|---|---|---|---|---|
| $0.00 | 2,324 | 100.0% | 2,019 | 100.0% |
| $1.00 | 2,017 | 86.8% | 1,760 | 87.2% |
| $5.00 | 859 | 37.0% | 1,081 | 53.5% |
| $10.00 | 365 | 15.7% | 618 | 30.6% |
| $15.00 | 215 | 9.3% | 415 | 20.6% |
| $20.00 | 129 | 5.6% | 273 | 13.5% |
| $25.00 | 89 | 3.8% | 192 | 9.5% |
| $50.00 | 21 | 0.9% | 63 | 3.1% |
| $75.00 | 10 | 0.4% | 30 | 1.5% |
| $100.00 | 6 | 0.3% | 16 | 0.8% |
| $200.00 | 1 | 0.0% | 2 | 0.1% |
| $300.00 | 0 | 0.0% | 2 | 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.[45]

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

In the first six 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

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

differences in institutional and operating practices between PJM and the NYISO. In the first six 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 six months of 2013, the PJM average hourly LMP at the PJM/NYISO border was $42.70 while the NYISO LMP at the border was $42.04, a difference of $0.66. While the average hourly LMP difference at the PJM/NYISO border was only $0.66, the average of the absolute value of the hourly difference was $14.29. The average hourly flow during the first six months of 2013 was -527 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 55.9 percent of the hours in the first six months of 2013. In the first six months of 2013, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $13.74. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $14.85. In the first six 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 $14.04. 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 $11.94. 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 $13.03. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from PJM to NYISO, the average price difference was $15.52.

In the first six months of 2013, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $43.86 while the NYIS LMP at the border was $43.05, a difference of $0.81.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-5). 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 8-6).

Figure 8–5 Real–time and day–ahead daily hourly average price difference (NY proxy – PJM/NYIS): January through June, 2013
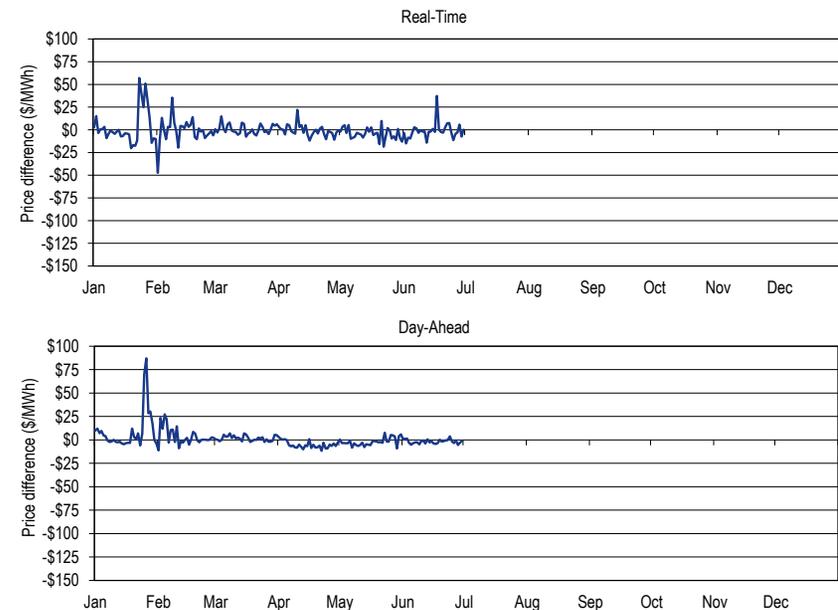


Distribution of Economic and Uneconomic Hourly Flows at the PJM/NYISO Interface

During the first six months of 2013, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 2,428 (55.9 percent of all hours), and was inconsistent with price differences in 1,915 hours (44.1 percent of all hours). Table 8-24 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 1,915 hours where flows were uneconomic, 1,736 of those hours (90.7

percent) had a price difference greater than or equal to $1.00 and 1,122 of all uneconomic hours (58.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $231.63. Of the 2,428 hours where flows were economic, 2,242 of those hours (92.3 percent) had a price difference greater than or equal to $1.00 and 1,493 of all economic hours (61.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $812.91.

### Table 8-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through June, 2013

| Price Difference Range (Greater Than or Equal To) | Uneconomic Hours | Percent of Total Hours | Economic Hours | Percent of Total Hours |
|---|---|---|---|---|
| $0.00 | 1,915 | 100.0% | 2,428 | 100.0% |
| $1.00 | 1,736 | 90.7% | 2,242 | 92.3% |
| $5.00 | 1,122 | 58.6% | 1,493 | 61.5% |
| $10.00 | 685 | 35.8% | 829 | 34.1% |
| $15.00 | 487 | 25.4% | 533 | 22.0% |
| $20.00 | 368 | 19.2% | 377 | 15.5% |
| $25.00 | 290 | 15.1% | 271 | 11.2% |
| $50.00 | 136 | 7.1% | 115 | 4.7% |
| $75.00 | 72 | 3.8% | 65 | 2.7% |
| $100.00 | 32 | 1.7% | 49 | 2.0% |
| $200.00 | 3 | 0.2% | 5 | 0.2% |
| $300.00 | 0 | 0.0% | 3 | 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 8-6, including average prices and measures of variability.

### Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through June, 2013
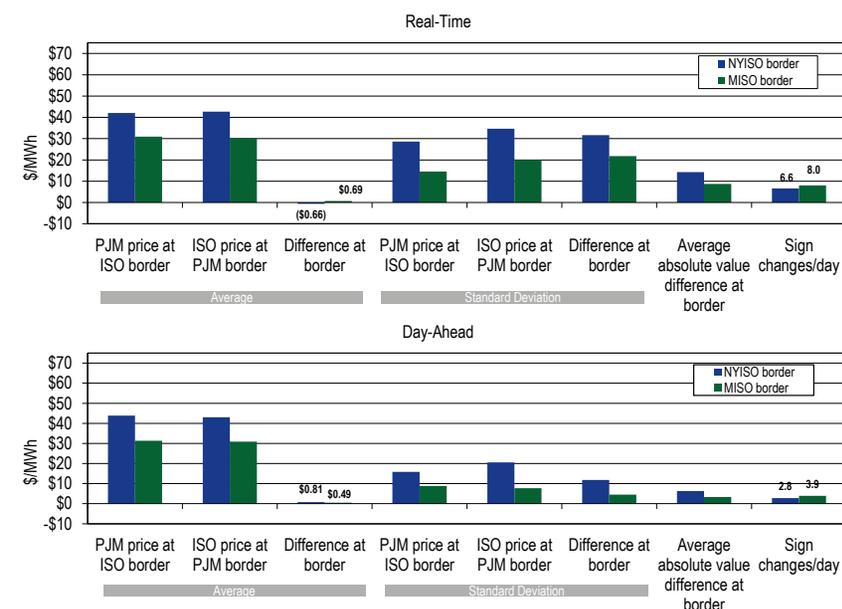


## Neptune Underwater Transmission Line to Long Island, New York

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 six 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 six months of 2013, the PJM average hourly LMP at the Neptune Interface was $40.08 while the NYISO LMP at the Neptune Bus was

$75.31, a difference of $35.22.[46] While the average hourly LMP difference at the PJM/Neptune border was $35.22, the average of the absolute value of the hourly difference was $43.39. The average hourly flow during the first six months of 2013 was -293 MW.[47] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 78.3 percent of the hours in the first six months of 2013. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average hourly price difference was $46.09. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $19.71.

**Figure 8-7 Neptune hourly average flow: January through June, 2013**



## Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a 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 six 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 six months of 2013, the PJM average hourly LMP at the Linden Interface was $41.42 while the NYISO LMP at the Linden Bus was $52.99, a difference of $11.56.[48] While the average hourly LMP difference at the PJM/Linden border was $11.56, the average of the absolute value of the hourly difference was $21.13. The average hourly flow during the first six months of 2013 was -139 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 70.6 percent of the hours in the first six months of 2013. When the NYISO/Linden Interface price was greater than the PJM/LIND Interface price, the average hourly price difference was $21.55. When the PJM/LIND Interface price was greater than the NYISO/Linden Interface price, the average price difference was $16.62.

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46 In the first six months of 2013, there were 833 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 $40.03 while the NYISO LMP at the Neptune Bus during non-zero flows was $71.87, a difference of $31.84.

47 The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -363 MW.

48 In the first six months of 2013, there were 841 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 $41.32 while the NYISO LMP at the Neptune Bus during non-zero flows was $51.64, a difference of $10.32.

49 The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Linden VFT line was -173 MW.

**Figure 8-8 Linden hourly average flow: January through June, 2013[50]**
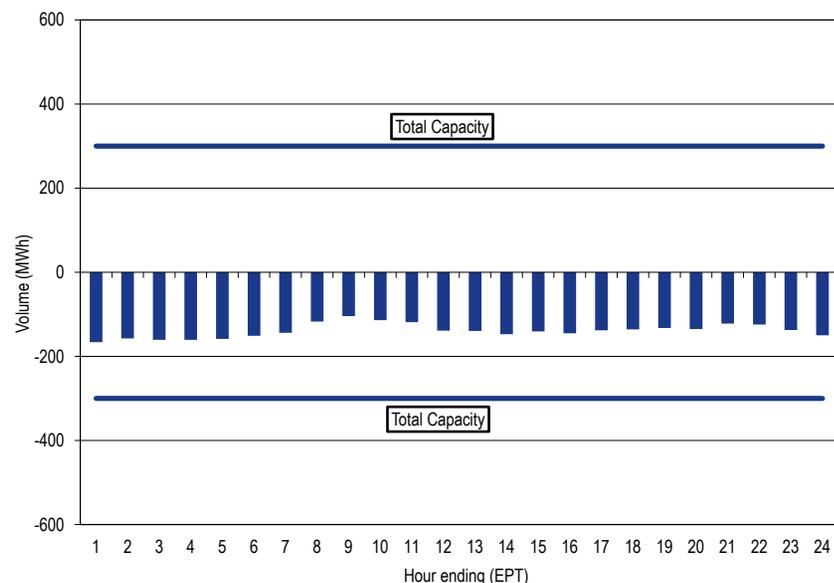


## Hudson Direct Current (DC) Merchant Transmission Line

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 June, 2013, the first month 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. The PJM average hourly LMP at the Hudson Interface was $39.54 while the NYISO LMP at the Hudson Bus was $42.46, a difference of $1.44.[51] While the average hourly LMP difference at the PJM/Hudson border was $1.44, the average of the absolute value of the hourly difference was $5.99. The average hourly flow during the first month of operations was -17 MW.[52] (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 six months of 2013. When the NYISO/Hudson Interface price was greater than the PJM/HUDS Interface price, the average hourly price difference was $9.14. When the PJM/HUDS Interface price was greater than the NYISO/Hudson Interface price, the average price difference was $8.89.

**Figure 8-9 Hudson hourly average flow: June, 2013**



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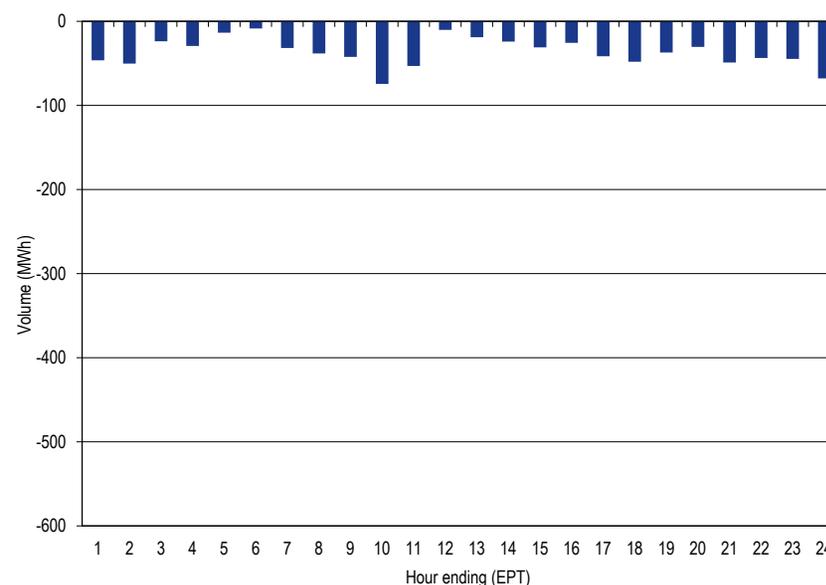
51 In the first month of operations, there were 550 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $37.17 while the NYISO LMP at the Hudson Bus during non-zero flows was $39.26, a difference of $2.09.
52 The average hourly flow during the first month of operations, ignoring hours with no flow, on the Hudson line was -147 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[53]

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.[54]

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.[55]

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

As of August 6, 2013, PJM had 166 flowgates and MISO had 269 flowgates eligible for M2M coordination. On May 10, 2013, PJM made an informational presentation to the PJM/MISO Joint and Common Market stakeholder meeting regarding the impacts of the market to market process on trends in PJM FTR revenue adequacy.[56] PJM requested input from stakeholders to determine if the issue should be considered as a future JCM initiative, as the difference in outage scheduling deadlines creates differences between the RTO's in their ability to add new M2M flowgates, which can contribute to underfunding due to the inability to account for the expected congestion in the FTR auction process. At the July 12, 2013, meeting of the PJM/MISO Joint and Common Market stakeholder meeting, PJM noted that further coordination of M2M flowgates was necessary to ensure the short-term FTR auctions included the new flowgates, which could minimize congestion on those facilities. PJM proposed that the RTOs agree on a list of flowgates prior to the yearly FTR allocation and auction process, and that the initiation of M2M redispatch caused by transmission outages or the initiation of new flowgates only occur if the non-monitoring RTO was notified of the outage or new flowgate within its internal outage scheduling deadline.[57]

During the first six 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 8-10 shows credits for coordinated congestion management between PJM and MISO.

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53 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 July 17, 2013)

54 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>.

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

56 See "*PJM FTR Revenue Adequacy Trends*," (May 10, 2013) <http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20130510/20130510-item-04-ftr-revenue-adequacy.ashx> (Accessed August 6, 2013)

57 See "*Outage Scheduling and Flowgate Additions*," (July 12, 2013) <http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20130712/20130712-item-02b-outages-and-new-flowgates-pjm.ashx> (Accessed August 6, 2013)

**Figure 8-10 Credits for coordinated congestion management: January through June, 2013**[58]
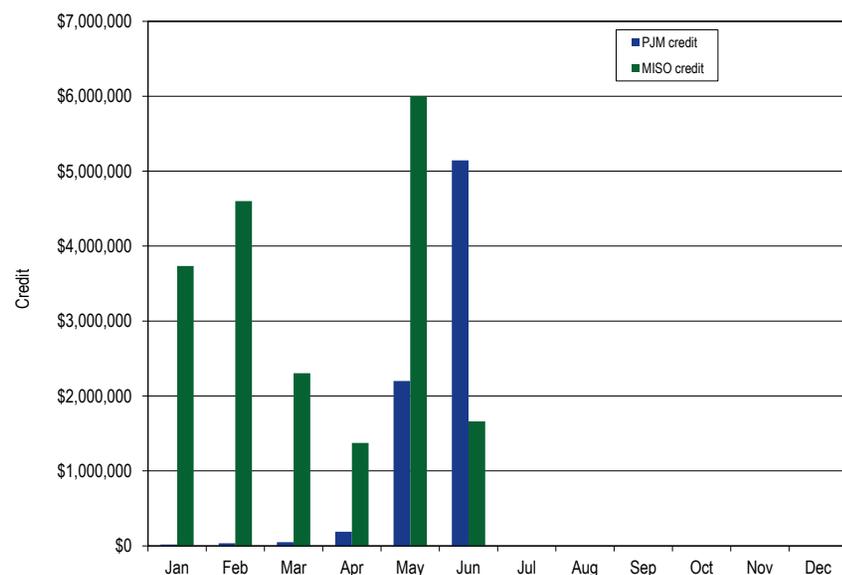


## PJM and New York Independent System Operator Joint Operating Agreement (JOA)[59]

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 six 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 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 six 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 8-11 shows credits for coordinated congestion management between PJM and NYISO.

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58 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
59 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 July 17, 2013)

**Figure 8-11 Credits for coordinated congestion management (flowgates): January through June, 2013[60]**
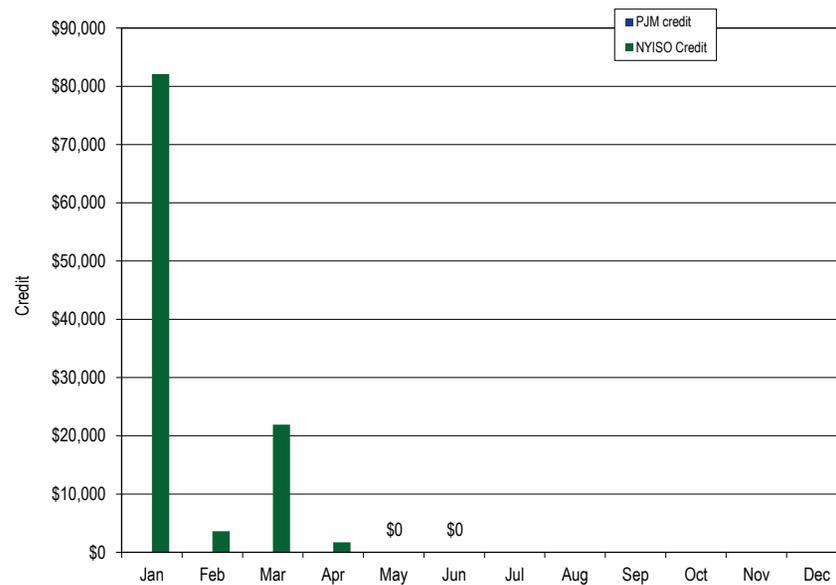


The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs 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.[61] 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 six months of 2013, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 8-12 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

**Figure 8-12 Credits for coordinated congestion management (Ramapo PARs): January through June, 2013[62]**



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60 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
61 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 July 17, 2013)
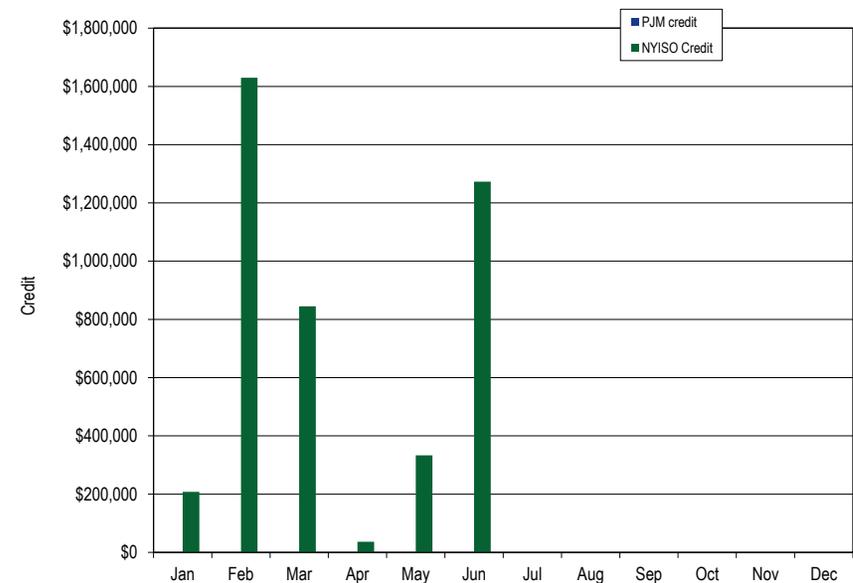
62 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

## 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 six months of 2013, there were no developments. The agreement continued to be in effect in the first six 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.[63] 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 six months of 2013, there were no developments. The agreement remained in effect in the first six months of 2013.

## 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.[64]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[65] 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.[66] 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.

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

64 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 July 17, 2013)
65 See *PJM Interconnection, L.L.C,* Docket No. ER10-2710-000 (September 17, 2010).
66 See Docket Nos. ER12-1338-000 and ER12-1343-000.

**Table 8-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through June, 2013**

|  | Import LMP | Export LMP | SOUTHIMP | SOUTHEXP | Difference IMP LMP – SOUTHIMP | Difference EXP LMP – SOUTHEXP |
|---|---|---|---|---|---|---|
| Duke | $34.05 | $34.73 | $33.92 | $33.92 | $0.13 | $0.81 |
| PEC | $34.96 | $35.68 | $33.92 | $33.92 | $1.04 | $1.76 |
| NCMPA | $34.40 | $34.50 | $33.92 | $33.92 | $0.48 | $0.59 |

**Table 8-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through June, 2013**

|  | Import LMP | Export LMP | SOUTHIMP | SOUTHEXP | Difference IMP LMP – SOUTHIMP | Difference EXP LMP – SOUTHEXP |
|---|---|---|---|---|---|---|
| Duke | $35.13 | $35.74 | $34.40 | $34.40 | $0.73 | $1.33 |
| PEC | $35.87 | $36.42 | $34.40 | $34.40 | $1.46 | $2.02 |
| NCMPA | $35.41 | $35.52 | $34.40 | $34.40 | $1.01 | $1.12 |

## 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.[67] 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.[68]

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[69] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special protocol indefinitely.[70] 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.[71] 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 8-27 below reflecting those charges effective May 1, 2012.

**Table 8-27 Con Edison and PSE&G wheeling agreement data: January through June, 2013**

| Billing Line Item | Con Edison | | | PSE&G | | |
|---|---|---|---|---|---|---|
|  | Day Ahead | Balancing | Total | Day Ahead | Balancing | Total |
| Congestion Charge | $4,517,940 | $15,116 | $4,533,057 | $0 | $0 | $0 |
| Congestion Credit |  |  | $2,025,540 |  |  | $0 |
| Adjustments and Transmission Charges |  |  | ($17,964,856) |  |  | $2,030 |
| Net Charge |  |  | $20,472,372 |  |  | ($2,030) |

## 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 23 TLRs of level 3a or high in the first six months of 2013, compared to eight TLRs issued in the first six months of 2012. The number of different flowgates for which PJM declared TLRs increased from four in the first six months of 2012 to 15 in the first six months of 2013. The total MWh of transaction curtailments increased by 385 percent, from 8,857 MWh in the first six months of 2012 to 34,061 MWh in the first six months of 2013.

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67 See "Section 3 – 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.
68 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.
69 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.
70 132 FERC ¶ 61,221 (2010).

71 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 8-28 PJM MISO, and NYISO TLR procedures: January, 2010 through June, 2013[72]

| Month | Number of TLRs Level 3 and Higher | | | Number of Unique Flowgates That Experienced TLRs | | | Curtailment Volume (MWh) | | |
|---|---|---|---|---|---|---|---|---|---|
| | 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 |

72 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 July 17, 2013)

MISO called more TLRs of level 3a or higher in the first six months of 2013 than in the first six months of 2012. MISO TLRs increased from 81 in the first six months of 2012 to 205 in the first six months of 2013.

NYISO called fewer TLRs of level 3a or higher in the first six months of 2013 than in the first six months of 2012. NYISO TLRs decreased from 54 in the first six months of 2012 to 3 in the first six months of 2013.

### Table 8-29 Number of TLRs by TLR level by reliability coordinator: January through June, 2013

| Year | Reliability Coordinator | 3a | 3b | 4 | 5a | 5b | 6 | Total |
|---|---|---|---|---|---|---|---|---|
| 2013 | ICTE | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | MISO | 66 | 22 | 1 | 78 | 38 | 0 | 205 |
| | NYIS | 3 | 0 | 0 | 0 | 0 | 0 | 3 |
| | ONT | 6 | 0 | 0 | 0 | 0 | 0 | 6 |
| | PJM | 11 | 11 | 0 | 1 | 0 | 0 | 23 |
| | SOCO | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | SWPP | 104 | 60 | 0 | 18 | 12 | 0 | 194 |
| | TVA | 17 | 17 | 0 | 3 | 3 | 0 | 40 |
| | VACS | 1 | 0 | 0 | 0 | 0 | 0 | 1 |
| Total | | 208 | 110 | 1 | 100 | 53 | 0 | 472 |

## 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.[73]

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 107,215 bids per day, with an average cleared volume of 1,272,955 MWh per day, in the first six months of 2013, compared to an

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

average of 54,180 bids per day, with an average cleared volume of 931,553 MWh per day, in the first six months of 2012 (See Figure 8-13).

The MMU is concerned about the impacts of the significant increase in up-to congestion transaction volume on the Day-Ahead Energy Market and on operating reserve charges. Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Up-to congestion transactions do not pay operating reserves charges and there is a question as to whether current credit policies adequately address up to congestion transactions. Additionally, the MMU is concerned about the potential for market participants to utilize up-to congestion transactions to affect their other market positions, and the potential impacts that up-to congestion transactions may have on meeting FTR target allocations.

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 equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

**Figure 8-13 Monthly up-to congestion cleared bids in MWh: January, 2005 through June, 2013**
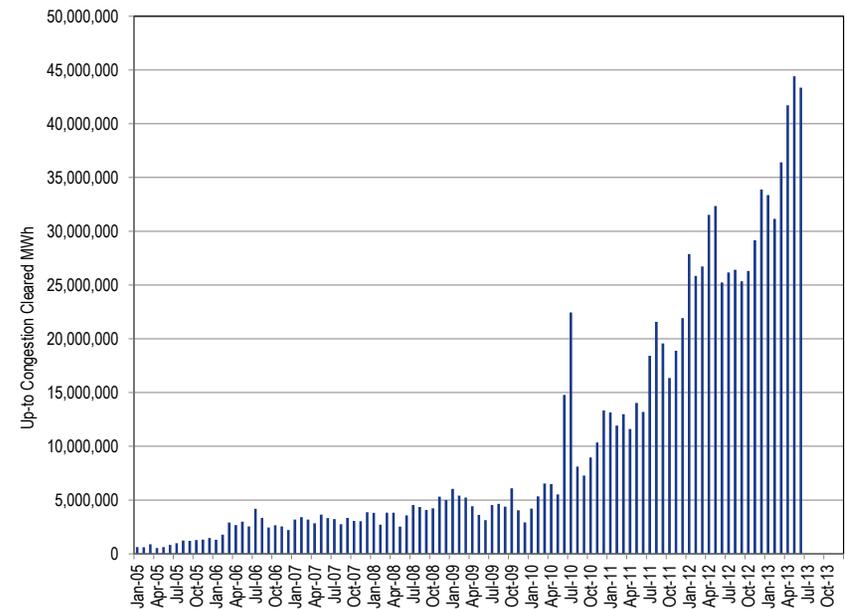
## Table 8-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through June, 2013

| Month | Bid MW | | | | | Bid Volume | | | | | Cleared MW | | | | | Cleared Volume | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 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 | 9,272,865 | 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 |
| TOTAL | 947,691,236 | 910,905,826 | 41,899,867 | 718,971,390 | 2,619,468,319 | 21,157,414 | 18,823,414 | 912,428 | 18,593,374 | 59,486,630 | 354,298,642 | 343,298,040 | 19,180,966 | 211,963,816 | 928,741,463 | 8,817,334 | 7,829,849 | 386,142 | 6,384,409 | 23,417,734 |

In the first six months of 2013, the cleared MW volume of up-to congestion transactions was comprised of 10.3 percent imports, 12.5 percent exports, 1.0 percent wheeling transactions and 76.2 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. This 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 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 six months of 2013 were -$2,860, compared to -$32 in the first six months of 2012 (Table 8-31). 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 six 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 six 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 8–31 Monthly uncollected congestion charges: January, 2010 through June, 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 | |
| Aug | $731,539 | $37 | $0 | |
| Sep | $119,162 | $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.[74] The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

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.

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

**Figure 8-14 Spot import service utilization: January, 2009 through June, 2013**
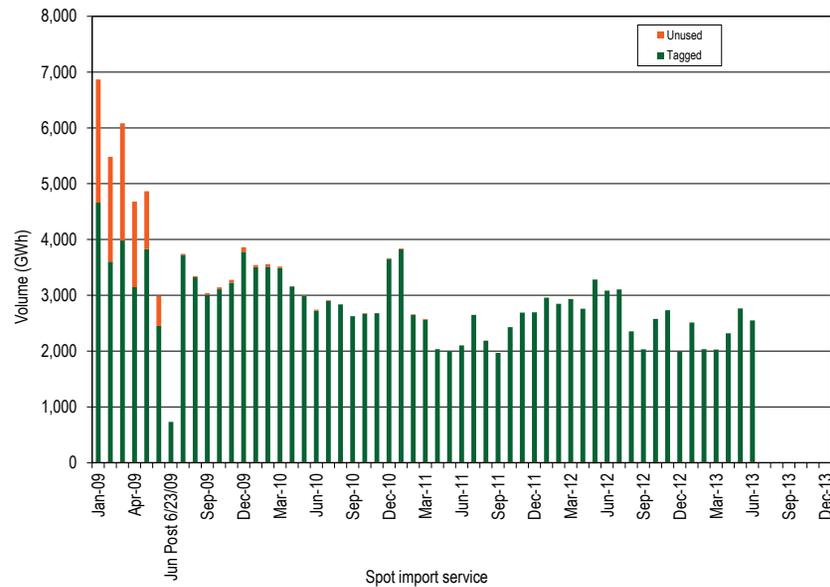


Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when 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 six months of 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.