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 nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first three months of 2019, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[1] In the first three months of 2019, the real-time net interchange was -6,731.8 GWh. The real-time net interchange in the first three months of 2018 was -1,610.2 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2019, PJM was a monthly net importer of energy in the Day-Ahead Energy Market in January and March, and a net exporter of energy in the February. In the first three months of 2019, the total day-ahead net interchange was 742.3 GWh. The day-ahead net interchange in the first three months of 2018 was -2,917.4.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2019, gross imports in the Day-Ahead Energy Market were 371.7 percent of gross imports in the Real-Time Energy Market (121.4 percent in the first three months of 2018). In the first three months of 2019, gross exports in the Day-Ahead Energy Market were 129.9 percent of the gross exports in the Real-Time Energy Market (134.3 percent in the first three months of 2018).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first three months of 2019, there were net scheduled exports at 11 of PJM's 19 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first three months of 2019, there were net scheduled exports at 8 of PJM's 17 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[2]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2019, there were net scheduled exports at 10 of PJM's 19 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2019, there were net scheduled exports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2019, up to congestion transactions were net exports at three of PJM's 18 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Inadvertent Interchange.** In the first three months of 2019, net scheduled interchange was -6,732 GWh and net actual interchange was -6,747 GWh, a difference of 15 GWh. In the first three months of 2018, the difference was 43 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first three months of 2019, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -1 GWh of net scheduled interchange and -2,814 GWh of net actual interchange, a difference of 2,813 GWh. In the first three months of 2019, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 2,387 GWh of net scheduled interchange and 8,518 GWh of net actual interchange, a difference of 6,131 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2019, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 54.2 percent of the hours.

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

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

- **PJM and New York ISO Interface Prices.** In the first three months of 2019, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 60.6 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2019, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 80.7 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2019, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 78.0 percent of the hours.
- **Hudson DC Line.** In the first three months of 2019, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 75.4 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in the first three months of 2019, compared to one such TLR issued in the first three months of 2018.
- **Up To Congestion.** On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[3] As a result, market participants reduced up to congestion trading effective February 22, 2018. The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 49.3 percent, from 105,194 bids per day in the first three months of 2018 to 53,376 bids per day in the first three months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market decreased by less than one percent, from 521,751 MWh per day in the first three months of 2018, to 521,709 MWh per day in the first three months of 2019.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[4] [5] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[6]

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing

3 162 FERC ¶ 61,139 (2018).

4 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

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

6 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)

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 nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Nonmarket areas do not include these features. Pricing in the market areas is transparent and pricing in the nonmarket areas is not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcomes that would exist in an LMP market across the interfaces.

Interchange Transaction Activity

Charges and Credits Applied to Interchange Transactions

Interchange transactions are subject to various charges and credits. These charges and credits are dependent on whether the interchange transaction is submitted in the Real-Time or Day-Ahead Energy Market, the type of transaction, the transmission service used and whether the transaction is an import, export or wheel. Table 9-1 shows the billing line items that represent the charges and credits applied to real-time and day-ahead interchange transactions.[7]

Table 9-1 Charges and credits applied to interchange transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		
Balancing Operating Reserve	X	X	X						
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

1 No charge if Point of Delivery is MISO

2 No charge for spot in transmission

7 For an explanation and current rate for each billing line item, see "*Customer Guide to PJM Billing*" (January 1, 2019) <http://www.pjm.com/~/media/markets-ops/settlements/custgd.ashx>.

Aggregate Imports and Exports

In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC). This integration eliminated the OVEC Interface and the OVEC Interface Pricing Point from the real-time and day-ahead markets. Eleven shareholders own portions of the Clifty Creek and Kyger Creek generation and share OVEC's generation output. The majority of generation output is owned by load serving entities or their affiliates located in the PJM footprint. Prior to integration, the Clifty Creek and Kyger Creek units were pseudo tied to PJM. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires the continued delivery of the remaining generation output that is not designated to serve PJM to points external to the PJM footprint.[8] Prior to integration, the contractual obligation to provide the portion of the generation output to points external to the PJM footprint were block scheduled exports at the OVEC interface. After the OVEC integration, with the elimination of the OVEC Interface, the continued contractual obligation to provide the portion of the generation output to points external to the PJM footprint will be to block schedule exports at the LGEE Interface.

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for the first three months of 2018 and 2019. In the first three months of 2019, gross imports in the Day-Ahead Energy Market were 371.7 percent of gross imports in the Real-Time Energy Market (121.4 percent in the first three months of 2018). In the first three months of 2019, gross exports in the Day-Ahead Energy Market were 129.9 percent of gross exports in the Real-Time Energy Market (134.3 percent in the first three months of 2018).

8 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (October 15, 2014).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): January through March, 2018 and 2019

Category	Jan-Mar 2018	Jan-Mar 2019
Real-Time Gross Imports	5,848.2	3,925.2
Real-Time Gross Exports	7,458.4	10,657.0
Real-Time Net Interchange	(1,610.2)	(6,731.8)
Day-Ahead Gross Imports	7,097.0	14,590.3
Day-Ahead Gross Exports	10,014.4	13,848.0
Day-Ahead Net Interchange	(2,917.4)	742.3
Monthly Average Real-Time Gross Exports	2,486.1	3,552.3
Monthly Average Real-Time Gross Imports	1,949.4	1,308.4
Monthly Average Day-Ahead Gross Exports	3,338.1	4,616.0
Monthly Average Day-Ahead Gross Imports	2,365.7	4,863.4

In the first three months of 2019, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months. In the first three months of 2019, PJM was a monthly net importer of energy in the Day-Ahead Energy Market in January and March, and a net exporter of energy in February (Figure 9-1).[9]

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

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 MWh in the Day-Ahead and Real-Time Energy Markets times the applicable operating reserve rates.[10] In the first three months of 2019, the total day-ahead gross imports and exports were higher than the real-time gross 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.

9 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
10 Up to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 9-1 Scheduled imports and exports: January through March, 2019

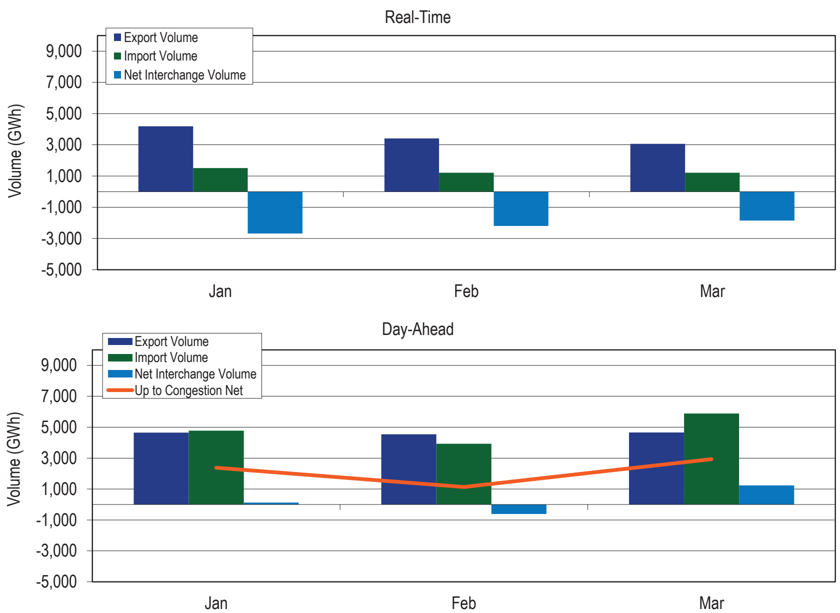
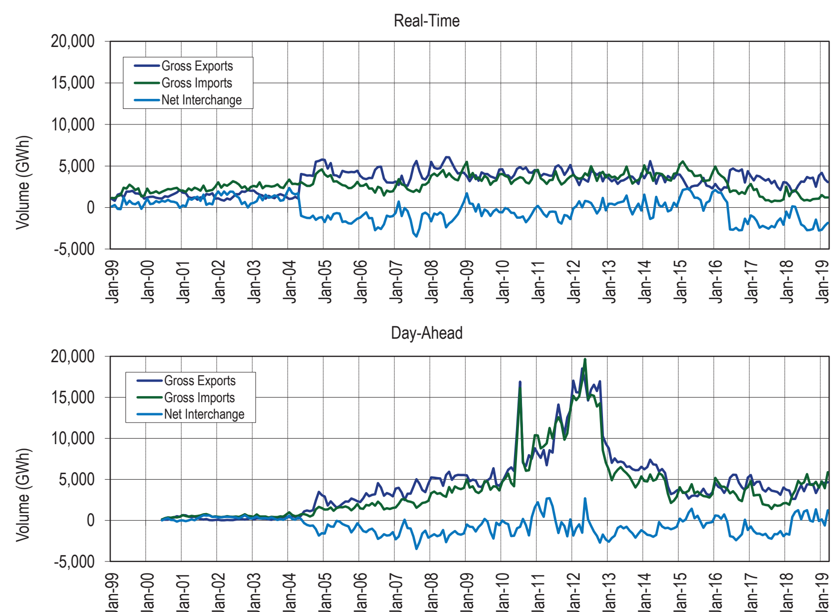


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through March 2019. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up to congestion product in September 2010, up to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Energy Market. On November 1, 2012, PJM eliminated the requirement that every up to congestion transaction include an interface pricing point as either the source or sink. As a result, the volume of import and export up to congestion transactions decreased, and the volume of internal up to congestion transactions increased. While the gross import and export volumes in the Day-Ahead Energy Market decreased, PJM has remained primarily a net exporter in the Day-Ahead Energy Market. The requirement for external capacity resources to be pseudo tied into PJM has affected the real-time and day-ahead import volumes. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to PJM remaining a net exporter in the Real-Time and Day-Ahead Energy Markets. The changes in up to congestion bidding behavior resulting from the February 20, 2018, FERC order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces contributed to PJM becoming a net importer in the Day-Ahead Energy Market starting in March, 2018.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through March 31, 2019



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are defined by the scheduled 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. Table 9-18 includes a list of active interfaces in the first three months of 2019. Figure 9-3 shows the approximate geographic location of the interfaces. In the first three months of 2019, PJM had 19 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 10 separate interfaces that make up the MISO Interface between PJM and MISO. Table 9-3 through Table 9-5 show the real-time energy market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the Real-Time Energy Market is shown by interface for the first three months of 2019 in Table 9-3, while gross scheduled imports and exports are shown in Table 9-4 and Table 9-5.

In the Real-Time Energy Market, in the first three months of 2019, there were net scheduled exports at 11 of PJM's 19 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 60.2 percent of the total net scheduled exports: PJM/Cinergy (CIN) with 24.9 percent, PJM/ New York Independent System Operator (NYIS) with 18.8 percent and PJM/ Neptune (NEPT) with 16.5 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/ NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 48.4 percent of the total net PJM scheduled exports in the Real-Time Energy Market. There were net scheduled exports in the Real-Time Energy Market at seven of the 10 separate interfaces that connect PJM to MISO. Those seven exporting interfaces represented 51.6 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

In the Real-Time Energy Market, in the first three months of 2019, there were net scheduled imports at seven of PJM's 19 interfaces. The top three importing interfaces in the Real-Time Energy Market accounted for 75.1 percent of the total net scheduled imports: PJM/Ameren-Illinois (AMIL) with 33.2 percent, PJM/ Duke Energy Corp. (DUK) with 28.7 percent and PJM/Michigan Electric Coordinated System (MECS) with 13.3 percent of the net scheduled import volume.[11] The four separate interfaces that connect PJM to the NYISO (PJM/ NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the Real-Time Energy Market. There were net scheduled imports in the Real-Time Energy Market at two of the 10 separate interfaces that connect PJM to MISO. Those two interfaces represented 46.4 percent of the total net PJM scheduled imports in the Real-Time Energy Market.

Table 9-3 Real-time scheduled net interchange volume by interface (GWh): January through March, 2019

	Jan	Feb	Mar	Total
CPLE	46.6	102.2	80.6	229.4
CPLW	(0.0)	0.0	0.3	0.2
DUK	(7.0)	265.4	243.5	502.0
LGEE	22.9	30.5	(4.9)	48.5
MISO	(1,235.4)	(1,568.2)	(756.4)	(3,560.0)
ALTE	(221.4)	(313.8)	(52.3)	(587.5)
ALTW	(5.3)	0.6	(4.6)	(9.4)
AMIL	316.0	106.1	157.8	579.9
CIN	(793.1)	(826.3)	(488.5)	(2,107.8)
CWLP	0.0	0.0	0.0	0.0
IPL	(36.5)	(34.8)	(58.4)	(129.7)
MEC	(536.0)	(435.1)	(400.4)	(1,371.6)
MECS	129.6	(10.2)	113.2	232.5
NIPS	(4.3)	3.9	(0.3)	(0.7)
WEC	(84.4)	(58.5)	(22.8)	(165.8)
NYISO	(1,558.3)	(1,124.8)	(1,425.5)	(4,108.6)
HUDS	(204.6)	(91.7)	(164.3)	(460.6)
LIND	(227.9)	(199.4)	(226.6)	(654.0)
NEPT	(464.5)	(436.9)	(496.3)	(1,397.7)
NYIS	(661.2)	(396.8)	(538.3)	(1,596.4)
TVA	52.5	96.0	8.1	156.6
Total	(2,678.7)	(2,198.9)	(1,854.3)	(6,731.8)

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

Table 9-4 Real-time scheduled gross import volume by interface (GWh): January through March, 2019

	Jan	Feb	Mar	Total
CPLE	161.9	144.3	165.6	471.7
CPLW	0.0	0.0	0.3	0.3
DUK	299.5	402.5	293.4	995.4
LGEE	113.4	101.6	93.3	308.3
MISO	665.3	290.4	468.2	1,424.0
ALTE	38.7	19.1	71.2	129.1
ALTW	0.1	0.6	0.0	0.6
AMIL	334.0	139.1	172.3	645.4
CIN	31.0	24.9	43.3	99.1
CWLP	0.0	0.0	0.0	0.0
IPL	4.1	3.0	3.7	10.8
MEC	19.2	17.1	24.1	60.5
MECS	231.4	77.7	152.0	461.1
NIPS	0.5	4.2	0.0	4.7
WEC	6.4	4.8	1.5	12.8
NYISO	163.0	125.9	125.3	414.2
HUDS	0.0	0.0	0.0	0.1
LIND	0.0	0.7	0.1	0.8
NEPT	0.0	0.0	0.0	0.0
NYIS	163.0	125.2	125.2	413.3
TVA	104.3	144.6	62.4	311.4
Total	1,507.5	1,209.2	1,208.5	3,925.2

Table 9-5 Real-time scheduled gross export volume by interface (GWh): January through March, 2019

	Jan	Feb	Mar	Total
CPLE	115.3	42.0	84.9	242.3
CPLW	0.0	0.0	0.0	0.0
DUK	306.5	137.0	49.9	493.4
LGEE	90.4	71.1	98.3	259.8
MISO	1,900.7	1,858.7	1,224.6	4,983.9
ALTE	260.1	332.9	123.6	716.5
ALTW	5.4	0.0	4.6	10.0
AMIL	17.9	33.0	14.6	65.5
CIN	824.0	851.1	531.7	2,206.9
CWLP	0.0	0.0	0.0	0.0
IPL	40.6	37.8	62.1	140.5
MEC	555.3	452.3	424.5	1,432.0
MECS	101.9	87.9	38.8	228.6
NIPS	4.8	0.3	0.3	5.4
WEC	90.8	63.4	24.4	178.6
NYISO	1,721.3	1,250.6	1,550.8	4,522.8
HUDS	204.6	91.7	164.3	460.7
LIND	228.0	200.0	226.7	654.7
NEPT	464.5	436.9	496.3	1,397.7
NYIS	824.2	522.0	663.5	2,009.7
TVA	51.8	48.6	54.3	154.7
Total	4,186.1	3,408.1	3,062.8	10,657.0

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 path on which scheduled imports or exports will flow.[12] 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 path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. 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 PJM/MISO Interface based on the scheduled path of the transaction. However,

12 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

the physical flow of energy does not enter the PJM footprint at the PJM/MISO 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 the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[13]

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 the contract transmission path.[14] 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. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 9-19 presents the interface pricing points used in the first three months of 2019. Figure 9-4 shows a map of the default interface pricing point assignments for all external balancing authorities. On September 16, 2014, PJM updated the mappings of external balancing authorities to individual pricing points. The MMU recommends that PJM review these mappings, at least annually, to reflect the fact that changes to the system topology can affect the impact of external power sources on PJM.

The interface pricing method implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally.[15] The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions.

The contract transmission 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), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to 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 breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive 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 which have since expired.[16]

In the Real-Time Energy Market, in the first three months of 2019, there were net scheduled exports at eight of PJM's 17 interface pricing points eligible for real-time transactions.[17] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 77.1 percent of the total net scheduled exports: PJM/MISO with 47.3 percent, PJM/NYIS with 15.9 percent and PJM/NEPTUNE with 13.9 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO

13 See the *2007 State of the Market Report for PJM*, Volume 2, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.
14 See "Interface Pricing Point Assignment Methodology" (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.
15 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario Interface Pricing Point.
16 Use of the Southwest pricing point for grandfathered transactions is not appropriate, and the MMU recommends that no further such agreements be entered into.
17 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

(PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 40.9 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

In the Real-Time Energy Market, in the first three months of 2019, there were net scheduled imports at five of PJM's 17 interface pricing points eligible for real-time transactions. The top two net importing interface pricing points in the Real-Time Energy Market accounted for 84.4 percent of the total net scheduled imports: PJM/SouthIMP with 72.2 percent and PJM/NCMPAIMP with 12.2 percent of the net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the Real-Time Energy Market.[18]

Table 9-6 Real-time scheduled net interchange volume by interface pricing point (GWh): January through March, 2019

	Jan	Feb	Mar	Total
IMO	193.2	86.2	82.4	361.7
MISO	(1,858.3)	(1,798.4)	(1,089.5)	(4,746.2)
NORTHWEST	0.0	0.0	0.0	0.0
NYISO	(1,559.3)	(1,124.8)	(1,425.5)	(4,109.6)
HUDSONTP	(204.6)	(91.7)	(164.3)	(460.6)
LINDENVFT	(227.9)	(199.4)	(226.6)	(654.0)
NEPTUNE	(464.5)	(436.9)	(496.3)	(1,397.7)
NYIS	(662.3)	(396.8)	(538.3)	(1,597.4)
Southern Imports	1,110.8	948.9	883.8	2,943.5
CPLEIMP	0.0	1.0	0.5	1.4
DUKIMP	40.2	42.7	69.0	151.9
NCMPAIMP	149.6	145.5	107.9	403.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	921.0	759.7	706.4	2,387.2
Southern Exports	(565.1)	(310.7)	(305.5)	(1,181.2)
CPLEEXP	(71.4)	(9.3)	(23.1)	(103.8)
DUKEXP	(137.8)	(86.6)	(10.1)	(234.5)
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	(355.8)	(214.8)	(272.3)	(842.9)
Total	(2,678.7)	(2,198.9)	(1,854.3)	(6,731.8)

18 In the Real-Time Energy Market, four PJM interface pricing points had a net interchange of zero (Northwest, Southeast, Southwest and NCMPAEXP).

Table 9-7 Real-time scheduled gross import volume by interface pricing point (GWh): January through March, 2019

	Jan	Feb	Mar	Total
IMO	196.6	88.0	83.2	367.8
MISO	38.1	46.5	116.1	200.7
NORTHWEST	0.0	0.0	0.0	0.0
NYISO	162.0	125.9	125.3	413.1
HUDSONTP	0.0	0.0	0.0	0.1
LINDENVFT	0.0	0.7	0.1	0.8
NEPTUNE	0.0	0.0	0.0	0.0
NYIS	161.9	125.2	125.2	412.3
Southern Imports	1,110.8	948.9	883.8	2,943.5
CPLEIMP	0.0	1.0	0.5	1.4
DUKIMP	40.2	42.7	69.0	151.9
NCMPAIMP	149.6	145.5	107.9	403.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	921.0	759.7	706.4	2,387.2
Southern Exports	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	1,507.5	1,209.2	1,208.5	3,925.2

Table 9-8 Real-time scheduled gross export volume by interface pricing point (GWh): January through March, 2019

	Jan	Feb	Mar	Total
IMO	3.4	1.8	0.9	6.1
MISO	1,896.4	1,844.9	1,205.6	4,946.9
NORTHWEST	0.0	0.0	0.0	0.0
NYISO	1,721.3	1,250.6	1,550.8	4,522.8
HUDSONTP	204.6	91.7	164.3	460.7
LINDENVFT	228.0	200.0	226.7	654.7
NEPTUNE	464.5	436.9	496.3	1,397.7
NYIS	824.2	522.0	663.5	2,009.7
Southern Imports	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
Southern Exports	565.1	310.7	305.5	1,181.2
CPLEEXP	71.4	9.3	23.1	103.8
DUKEXP	137.8	86.6	10.1	234.5
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	355.8	214.8	272.3	842.9
Total	4,186.1	3,408.1	3,062.8	10,657.0

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 path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than in the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[19] 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.[20]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by market participants. In Table 9-9, Table 9-10, and Table 9-11, the scheduled 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, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP interface price. As a result, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Energy Market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the scheduled interface pricing point tables, the import transaction would

19 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

20 See the *2010 State of the Market Report for PJM*, Volume 2, Section 4, "Interchange Transactions," for details.

appear as scheduled through the SouthIMP/EXP interface pricing point, which reflects the expected power flow.

Table 9-9 through Table 9-11 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the Day-Ahead Energy Market is shown by interface for the first three months of 2019 in Table 9-9, while gross scheduled imports and exports are shown in Table 9-10 and Table 9-11.

In the Day-Ahead Energy Market, in the first three months of 2019, there were net scheduled exports at 10 of PJM's 19 interfaces. The top three net exporting interfaces in the Day-Ahead Energy Market accounted for 67.2 percent of the total net scheduled exports: PJM/NYIS with 24.3 percent, PJM/Neptune (NEPT) with 21.7 percent, and PJM/ MidAmerican Energy Company (MEC) with 21.2 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 49.0 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. In the first three months of 2019, there were net exports in the Day-Ahead Energy Market at six of the 10 separate interfaces that connect PJM to MISO. Those six interfaces represented 50.0 percent of the total net PJM exports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in the first three months of 2019, there were net scheduled imports at two of PJM's 19 interfaces. The top two net importing interfaces in the Day-Ahead Energy Market accounted for 100.0 percent of the total net scheduled imports: PJM/CPLE[21] with 51.5 percent and PJM/Duke Energy Corp. (DUK) with 48.5 percent of the net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the Day-Ahead Energy Market. In the first three months of 2019, there were net imports in the Day-Ahead Energy Market at none of the 10 separate interfaces that connect PJM to MISO.[22]

21 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.
22 In the Day-Ahead Energy Market, seven PJM interfaces had a net interchange of zero (PJM/Carolina Power and Light (West) (CPLW), PJM/Louisville Gas & Electric/Kentucky Utilities (LGEE), PJM/Ameren Illinois (AMIL), PJM/City Water Light & Power (CWLP), PJM/Indianapolis Power and Light Company (IPL), PJM/Northern Indiana Public Service Company (NIPS) and PJM/Linden (LIND)).

Table 9-9 Day-ahead scheduled net interchange volume by interface (GWh): January through March, 2019

	Jan	Feb	Mar	Total
CPLE	159.7	130.7	88.9	379.3
CPLW	0.0	0.0	0.0	0.0
DUK	104.1	161.7	92.0	357.8
LGEE	0.0	0.0	0.0	0.0
MISO	(1,270.9)	(1,187.1)	(757.2)	(3,215.3)
ALTE	(198.1)	(220.9)	(65.7)	(484.8)
ALTW	(3.9)	0.0	0.0	(3.9)
AMIL	0.0	0.0	0.0	0.0
CIN	(446.3)	(405.9)	(270.5)	(1,122.8)
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0
MEC	(525.0)	(443.0)	(398.5)	(1,366.5)
MECS	(34.7)	(54.1)	0.3	(88.5)
NIPS	0.0	0.0	0.0	0.0
WEC	(62.9)	(63.2)	(22.8)	(148.9)
NYISO	(1,227.8)	(835.5)	(1,089.0)	(3,152.3)
HUDS	(106.9)	(38.3)	(49.1)	(194.3)
LIND	0.0	0.0	0.0	0.0
NEPT	(457.1)	(441.3)	(499.0)	(1,397.4)
NYIS	(663.8)	(355.9)	(541.0)	(1,560.6)
TVA	(15.0)	(15.5)	(34.5)	(65.0)
Total without Up To Congestion	(2,249.9)	(1,745.7)	(1,699.8)	(5,695.5)
Up To Congestion	2,376.2	1,131.3	2,930.3	6,437.8
Total	126.3	(614.4)	1,230.4	742.3

Table 9-10 Day-ahead scheduled gross import volume by interface (GWh): January through March, 2019

	Jan	Feb	Mar	Total
CPLE	207.7	159.5	142.5	509.7
CPLW	0.0	0.0	0.0	0.0
DUK	104.1	161.7	93.4	359.2
LGEE	0.0	0.0	0.0	0.0
MISO	56.9	38.4	51.3	146.5
ALTE	3.7	3.4	33.6	40.6
ALTW	0.0	0.0	0.0	0.0
AMIL	0.0	0.0	0.0	0.0
CIN	4.4	3.5	10.7	18.7
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0
MEC	1.7	0.0	0.0	1.7
MECS	47.1	31.4	7.0	85.5
NIPS	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0
NYISO	37.2	19.4	0.2	56.8
HUDS	0.0	0.0	0.0	0.0
LIND	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0
NYIS	37.2	19.4	0.2	56.8
TVA	0.0	0.0	0.0	0.0
Total without Up To Congestion	405.8	379.0	287.4	1,072.2
Up To Congestion	4,365.8	3,552.0	5,600.3	13,518.1
Total	4,771.6	3,931.0	5,887.7	14,590.3

Table 9-11 Day-ahead scheduled gross export volume by interface (GWh): January through March, 2019

	Jan	Feb	Mar	Total
CPLE	48.0	28.9	53.6	130.4
CPLW	0.0	0.0	0.0	0.0
DUK	0.0	0.0	1.4	1.4
LGEE	0.0	0.0	0.0	0.0
MISO	1,327.8	1,225.5	808.5	3,361.8
ALTE	201.8	224.3	99.3	525.4
ALTW	3.9	0.0	0.0	3.9
AMIL	0.0	0.0	0.0	0.0
CIN	450.8	409.5	281.2	1,141.4
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0
MEC	526.7	443.0	398.5	1,368.2
MECS	81.8	85.5	6.7	174.0
NIPS	0.0	0.0	0.0	0.0
WEC	62.9	63.2	22.8	148.9
NYISO	1,264.9	854.9	1,089.3	3,209.1
HUDS	106.9	38.3	49.1	194.3
LIND	0.0	0.0	0.0	0.0
NEPT	457.1	441.3	499.0	1,397.4
NYIS	700.9	375.3	541.2	1,617.4
TVA	15.0	15.5	34.5	65.0
Total without Up To Congestion	2,655.7	2,124.7	1,987.3	6,767.7
Up To Congestion	1,989.6	2,420.7	2,670.0	7,080.3
Total	4,645.3	4,545.4	4,657.3	13,848.0

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-12 through Table 9-17 show the day-ahead scheduled interchange totals at the interface pricing points. In the first three months of 2019, up to congestion transactions accounted for 92.7 percent of all scheduled import MW transactions and 51.1 percent of all scheduled export MW transactions in the Day-Ahead Energy Market. The day-ahead net scheduled interchange in the first three months of 2019, including up to congestion transactions, is shown by interface pricing point in Table 9-12. Scheduled up to congestion transactions by interface pricing point in the first three months of 2019 are shown in Table 9-13. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-14 and Table

9-16, while gross scheduled import and export up to congestion transactions are show in Table 9-15 and Table 9-17.

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

After NIPSCO integrated into MISO on May 1, 2004, PJM kept the NIPSCO interface pricing point for the purpose of facilitating the long term day-ahead positions created at the NIPSCO Interface prior to the integration. However, the NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market today, and is available for all market participants to use as the pricing point for day-ahead imports, exports and wheels, INCs, DECs and up to congestion transactions. The NIPSCO interface pricing point continued to also be used as an eligible source or sink for new FTRs through the 2016/2017 planning period, but was removed as an eligible bus for the 2017/2018 planning period.

In the first three months of 2019, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -2,255.7 GWh (Table 9-12). Table 9-13 shows that all -2,255.7 GWh of day-ahead net scheduled interchange submitted at the NIPSCO interface pricing point were made up of up to congestion transactions. While there is no corresponding interface pricing point available for real-time transaction scheduling, a real-time LMP is still calculated. This real-time price is used for balancing the deviations between the Day-Ahead and Real-Time Energy Markets.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface pricing point with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006. At that time, the real-time Southeast and Southwest interface pricing points remained only to support certain grandfathered agreements with specific generating units and to price energy under the reserve sharing agreement with VACAR. The reserve sharing agreement allows for the transfer of energy during emergencies. Interchange transactions created as part of the reserve sharing agreement are currently settled at the Southeast interface price. PJM also kept the day-ahead Southeast and Southwest interface pricing points to facilitate long-term day-ahead positions that were entered prior to the consolidation.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. PJM should immediately eliminate interface pricing points when changes to the market mean that the pricing points can no longer be used to price actual transactions and do not reflect actual price formation.

In the Day-Ahead Energy Market, in the first three months of 2019, there were net scheduled exports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 70.6 percent of the total net scheduled exports: PJM/NIPSCO with 35.0 percent, PJM/NYIS with 20.5 percent and PJM/MISO with 15.1 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 40.7 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. However, the PJM/LINDENVFT interface pricing point had net scheduled imports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in the first three months of 2019, there were net scheduled imports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points in the Day-Ahead Energy Market accounted for 90.5 percent of the total net scheduled imports: PJM/SouthImp with 42.5 percent, PJM/NORTHWEST with 41.0 percent and PJM/NCMPAIMP with 6.9 percent of the net import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 3.0 percent of the total net PJM scheduled imports in the Day-Ahead Energy Market. However, the PJM/NYIS, PJM/NEPTUNE and PJM/HUDSONTP interface pricing points had net scheduled exports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in the first three months of 2019, up to congestion transactions had net scheduled exports at three of PJM's 18 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 87.1 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 73.8 percent and PJM/HUDSONTP with 13.3 percent of the net up to congestion scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 13.3 percent of the total net scheduled up to congestion exports in the Day-Ahead Energy Market. However, the PJM/NYIS, PJM/NEPTUNE and PJM/LINDENVFT interface pricing points had net up to congestion scheduled imports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in the first three months of 2019, up to congestion transactions had net scheduled imports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points eligible for up to congestion transactions accounted for 86.2 percent of the total net up to congestion scheduled imports: PJM/NORTHWEST with 44.8 percent, PJM/SouthImp with 30.5 percent and PJM/MISO with 10.9 percent of the net import up to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 12.0 percent of the total net scheduled up to congestion imports in the Day-Ahead Energy Market. However, the PJM/HUDSONTP interface pricing points had net up to congestion scheduled exports in the Day-Ahead Energy Market.[23]

Table 9-12 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through March, 2019

	Jan	Feb	Mar	Total
IMO	120.3	82.9	51.3	254.5
MISO	(405.0)	(801.4)	232.2	(974.3)
NIPSCO	(524.1)	(412.7)	(1,318.9)	(2,255.7)
NORTHWEST	1,323.3	(117.7)	1,739.0	2,944.6
NYISO	(1,126.4)	(632.1)	(641.4)	(2,399.9)
HUDSONTP	(218.7)	(288.3)	(75.0)	(582.0)
LINDENVFT	99.2	0.5	118.8	218.4
NEPTUNE	(308.0)	(184.3)	(224.1)	(716.4)
NYIS	(698.8)	(160.1)	(461.0)	(1,319.9)
Southern Imports	939.8	1,448.3	1,377.0	3,765.1
CPLEIMP	53.3	23.6	28.2	105.1
DUKIMP	26.8	51.6	29.3	107.7
NCMPAIMP	180.7	176.8	140.2	497.8
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	679.1	1,196.3	1,179.2	3,054.6
Southern Exports	(201.6)	(181.6)	(208.8)	(592.0)
CPLEEXP	(45.1)	(27.1)	(50.8)	(123.0)
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	(156.4)	(154.6)	(158.0)	(469.0)
Total	126.3	(614.4)	1,230.4	742.3

23 In the Day-Ahead Energy Market, eight PJM interface pricing points had up to congestion net interchange of zero (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP, PJM/NCMPAEXP, PJM/Southeast and PJM/Southwest).

Table 9-13 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January through March, 2019

	Jan	Feb	Mar	Total
IMO	74.4	49.9	43.3	167.5
MISO	431.1	(6.9)	610.7	1,034.9
NIPSCO	(524.1)	(412.7)	(1,318.9)	(2,255.7)
NORTHWEST	1,812.5	315.9	2,124.9	4,253.3
NYISO	92.9	195.4	447.7	736.0
HUDSONTP	(120.4)	(258.6)	(27.1)	(406.0)
LINDENVFT	99.2	0.5	118.8	218.4
NEPTUNE	149.1	257.1	274.8	681.0
NYIS	(35.0)	196.5	81.1	242.6
Southern Imports	628.0	1,127.0	1,141.1	2,896.1
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	628.0	1,127.0	1,141.1	2,896.1
Southern Exports	(138.5)	(137.3)	(118.5)	(394.3)
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	(138.5)	(137.3)	(118.5)	(394.3)
Total Interfaces	2,376.2	1,131.3	2,930.3	6,437.8
INTERNAL	9,708.1	9,029.3	10,124.5	28,861.9
Total	12,084.3	10,160.6	13,054.8	35,299.7

Table 9-14 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through March, 2019

	Jan	Feb	Mar	Total
IMO	152.0	135.3	80.3	367.6
MISO	863.4	515.5	1,137.6	2,516.4
NIPSCO	112.2	133.2	156.6	402.0
NORTHWEST	2,074.1	969.4	2,320.0	5,363.5
NYISO	630.1	729.4	816.3	2,175.8
HUDSONTP	43.1	43.7	80.1	166.9
LINDENVFT	154.0	103.2	173.2	430.4
NEPTUNE	207.3	293.3	309.0	809.6
NYIS	225.8	289.3	254.0	769.0
Southern Imports	939.8	1,448.3	1,377.0	3,765.1
CPLEIMP	53.3	23.6	28.2	105.1
DUKIMP	26.8	51.6	29.3	107.7
NCMPAIMP	180.7	176.8	140.2	497.8
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	679.1	1,196.3	1,179.2	3,054.6
Southern Exports	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	4,771.6	3,931.0	5,887.7	14,590.3

Table 9-15 Up to congestion scheduled gross import volume by interface pricing point (GWh): January through March, 2019

	Jan	Feb	Mar	Total
IMO	104.9	102.3	71.2	278.3
MISO	853.6	510.1	1,095.4	2,459.1
NIPSCO	112.2	133.2	156.6	402.0
NORTHWEST	2,074.1	969.4	2,320.0	5,363.5
NYISO	593.0	710.0	816.0	2,119.1
HUDSONTP	43.1	43.7	80.1	166.9
LINDENVFT	154.0	103.2	173.2	430.4
NEPTUNE	207.3	293.3	309.0	809.6
NYIS	188.7	269.9	253.7	712.3
Southern Imports	628.0	1,127.0	1,141.1	2,896.1
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	628.0	1,127.0	1,141.1	2,896.1
Southern Exports	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total Interfaces	4,365.8	3,552.0	5,600.3	13,518.1

Table 9-16 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through March, 2019

	Jan	Feb	Mar	Total
IMO	31.7	52.4	29.0	113.1
MISO	1,268.4	1,316.9	905.4	3,490.7
NIPSCO	636.4	545.9	1,475.5	2,657.7
NORTHWEST	750.8	1,087.1	581.0	2,418.8
NYISO	1,756.6	1,361.5	1,457.6	4,575.7
HUDSONTP	261.9	332.0	155.0	748.9
LINDENVFT	54.8	102.7	54.4	211.9
NEPTUNE	515.3	477.5	533.2	1,526.0
NYIS	924.6	449.3	715.0	2,088.9
Southern Imports	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
Southern Exports	201.6	181.6	208.8	592.0
CPLEEXP	45.1	27.1	50.8	123.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	156.4	154.6	158.0	469.0
Total	4,645.3	4,545.4	4,657.3	13,848.0

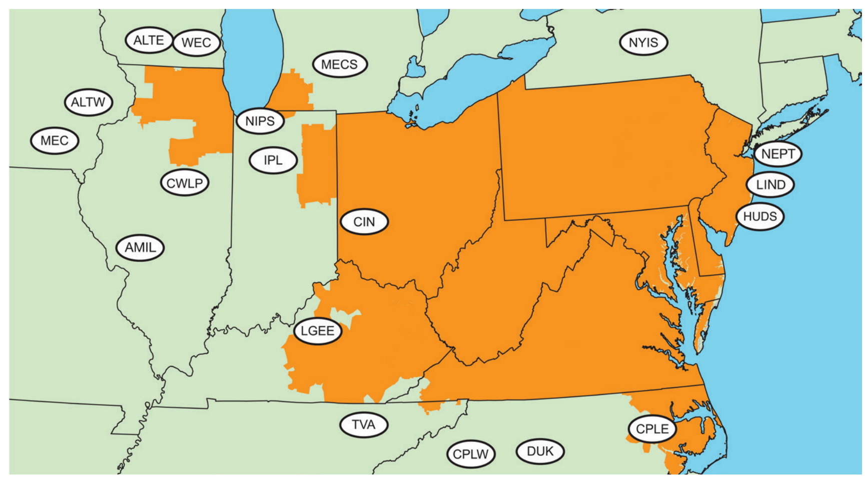
Table 9-17 Up to congestion scheduled gross export volume by interface pricing point (GWh): January through March, 2019

	Jan	Feb	Mar	Total
IMO	30.5	52.4	27.9	110.8
MISO	422.5	517.0	484.7	1,424.2
NIPSCO	636.4	545.9	1,475.5	2,657.7
NORTHWEST	261.6	653.5	195.1	1,110.2
NYISO	500.1	514.6	368.4	1,383.1
HUDSONTP	163.5	302.3	107.1	572.9
LINDENVFT	54.8	102.7	54.4	211.9
NEPTUNE	58.2	36.2	34.2	128.6
NYIS	223.7	73.4	172.6	469.7
Southern Imports	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
Southern Exports	138.5	137.3	118.5	394.3
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	138.5	137.3	118.5	394.3
Total Interfaces	1,989.6	2,420.7	2,670.0	7,080.3

Table 9-18 Active scheduling interfaces: 2019[24]

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

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



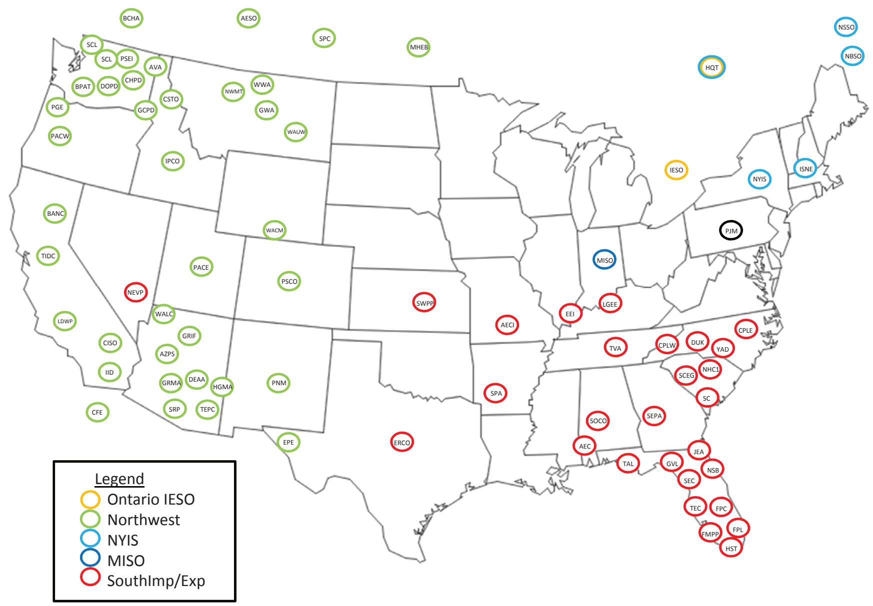
24 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of March 31, 2019, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Table 9-19 Active scheduled interface pricing points: January through March, 2019[25]

	Jan	Feb	Mar
CPLEEXP	Active	Active	Active
CPLEIMP	Active	Active	Active
DUKEXP	Active	Active	Active
DUKIMP	Active	Active	Active
HUDSONTP	Active	Active	Active
LINDENVFT	Active	Active	Active
MISO	Active	Active	Active
NCMPAEXP	Active	Active	Active
NCMPAIMP	Active	Active	Active
NEPTUNE	Active	Active	Active
NIPSCO	Active	Active	Active
Northwest	Active	Active	Active
NYIS	Active	Active	Active
Ontario IESO	Active	Active	Active
Southeast	Active	Active	Active
SOUTHEXP	Active	Active	Active
SOUTHIMP	Active	Active	Active
Southwest	Active	Active	Active

25 The NIPSCO interface pricing point is valid only in the Day-Ahead Energy Market.

Figure 9-4 External balancing authority default interface pricing point assignments



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 a specific interface. 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.[26]

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

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at PJM's borders. For example, if a 100 MW transaction were submitted, there would be 100 MW of scheduled flow at the PJM/MISO interface border, but there would be no actual flows on the interface. Correspondingly, there would be no scheduled flows at the PJM/Southern interface border, but there would be 100 MW of actual flows on the interface. In the first three months of 2019, there were net scheduled flows of 887 GWh through MISO that received an interface pricing point associated with the southern interface but there were no net scheduled flows across the southern interface that received the MISO interface pricing point.

26 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

In the first three months of 2019, net scheduled interchange was -6,732 GWh and net actual interchange was -6,747 GWh, a difference of 15 GWh. In the first three months of 2018, net scheduled interchange was -1,610 GWh and net actual interchange was -1,653 GWh, a difference of 43 GWh. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange using unilateral or bilateral paybacks.[27]

Table 9-20 shows that in the first three months of 2019, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -1 GWh of net scheduled interchange and -2,814 GWh of net actual interchange, a difference of 2,813 GWh.

Table 9-20 Net scheduled and actual PJM flows by interface (GWh): January through March, 2019

	Actual	Net Scheduled	Difference (GWh)
CPLE	671	229	441
CPLW	(201)	0	(201)
DUK	642	502	140
LGEE	1,319	48	1,271
MISO	(7,224)	(3,560)	(3,664)
ALTE	(991)	(587)	(404)
ALTW	(655)	(9)	(645)
AMIL	(497)	580	(1,077)
CIN	(1,753)	(2,108)	355
CWLP	(13)	0	(13)
IPL	(308)	(130)	(178)
MEC	(1,139)	(1,372)	233
MECS	31	233	(202)
NIPS	(2,814)	(1)	(2,813)
WEC	915	(166)	1,081
NYISO	(4,059)	(4,109)	49
HUDS	(461)	(461)	0
LIND	(654)	(654)	0
NEPT	(1,398)	(1,398)	0
NYIS	(1,547)	(1,596)	49
TVA	2,105	157	1,948
Total	(6,747)	(6,732)	(15)

27 See PJM. "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019).

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 MWh of scheduled transactions that will receive the interface pricing point based on the external balancing authority mapping.[28] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SouthIMP interface pricing point net schedule totals because SPP is mapped to the SouthIMP interface pricing point. 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 MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-21 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 reflect the same physical ties as 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. In the case of PJM's southern border, loop flows can be analyzed by comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points. To accurately calculate the loop flows from the southern region, the net actual flows from the southern region are compared to the net scheduled flows from the southern region. The net actual flows from the southern region are determined by summing the total southern import actual flows (8,518 GWh) and the total southern export actual flows (-3,982 GWh) for 4,536 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (2,943 GWh) and the total southern export scheduled flows (-1,181 GWh) for 1,762 GWh of net imports. In the first three months of 2019, the loop flows at the southern region were the difference between the southern region net scheduled flows (1,762 GW) and the southern region net actual flows (4,536 GWh) for a total of 2,774 GWh of loop flows.

The IMO interface pricing point with the Ontario IESO was created to reflect the fact that transactions that originate or sink in the Ontario Independent Electricity System Operator (IMO) balancing authority create physical flows that are split between the MISO and NYISO interface pricing points depending on transmission system conditions, 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. Table 9-21 shows actual flows associated with the IMO interface pricing point 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.

28 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance.

Table 9-21 PJM flows by interface pricing point (GWh): January through March, 2019

	Actual	Net Scheduled	Difference (GWh)
IMO	0	362	(362)
MISO	(7,224)	(4,746)	(2,477)
NORTHWEST	0	0	0
NYISO	(4,059)	(4,110)	50
HUDSONTP	(461)	(461)	0
LINDENVFT	(654)	(654)	0
NEPTUNE	(1,398)	(1,398)	0
NYIS	(1,547)	(1,597)	50
Southern Imports	8,518	2,943	5,575
CPLEIMP	0	1	(1)
DUKIMP	0	152	(152)
NCMPAIMP	0	403	(403)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	8,518	2,387	6,131
Southern Exports	(3,982)	(1,181)	(2,801)
CPLEEXP	0	(104)	104
DUKEXP	0	(235)	235
NCMPAEXP	0	0	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(3,982)	(843)	(3,139)
Total	(6,747)	(6,732)	(15)

Table 9-22 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 IMO entered the PJM energy market. For example, Table 9-24 shows that 361 of the 362 GWh (99.7 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled as imports through MISO, and 1 of the 362 GWh (0.3 percent) were scheduled as imports through the NYISO.

Table 9-22 shows that in the first three months of 2019, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 2,387 GWh of net scheduled interchange and 8,518 GWh of net actual interchange, a difference of 6,131 GWh.

Table 9-22 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through March, 2019

	Actual	Net Scheduled	Difference (GWh)
MISO	(7,224)	(4,385)	(2,838)
NORTHWEST	0	0	0
NYISO	(4,059)	(4,109)	49
HUDSONTP	(461)	(461)	0
LINDENVFT	(654)	(654)	0
NEPTUNE	(1,398)	(1,398)	0
NYIS	(1,547)	(1,596)	49
Southern Imports	8,518	2,943	5,575
CPLEIMP	0	1	(1)
DUKIMP	0	152	(152)
NCMPAIMP	0	403	(403)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	8,518	2,387	6,131
Southern Exports	(3,982)	(1,181)	(2,801)
CPLEEXP	0	(104)	104
DUKEXP	0	(235)	235
NCMPAEXP	0	0	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(3,982)	(843)	(3,139)
Total	(6,747)	(6,732)	(15)

PJM attempts to ensure 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 Tag. Assigning prices in this manner is a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method does not address loop flow issues.

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

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

The MMU also recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows.

Table 9-23 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 paths at each of PJM's interfaces. For example, Table 9-23 shows that in the first three months of 2019, the majority of imports to the PJM energy market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the SOUTHIMP Interface, and thus actual flows were assigned the SOUTHIMP interface pricing point (23 GWh). 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 were assigned the MISO interface pricing point (-2,118 GWh).

Table 9-23 Net scheduled and actual flows by interface and interface pricing point (GWh): January through March, 2019

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
ALTE		(991)	(587)	(404)	IPL		(308)	(130)	(178)
	IMO	0	62	(62)		IMO	0	4	(4)
	MISO	(991)	(653)	(339)		MISO	(308)	(130)	(178)
	SOUTHEXP	0	(1)	1		SOUTHEXP	0	(3)	3
	SOUTHIMP	0	4	(4)		SOUTHIMP	0	0	(0)
ALTW		(655)	(9)	(645)	LGEE		1,319	48	1,271
	MISO	(655)	(5)	(650)		SOUTHEXP	(1,829)	(260)	(1,569)
	SOUTHEXP	0	(5)	5		SOUTHIMP	3,148	308	2,840
AMIL		(497)	580	(1,077)	LIND		(654)	(654)	0
	MISO	(497)	(62)	(435)		LINDENVFT	(654)	(654)	0
	SOUTHIMP	0	642	(642)	MEC		(1,139)	(1,372)	233
CIN		(1,753)	(2,108)	355		MISO	(1,139)	(1,375)	236
	IMO	0	2	(2)		SOUTHEXP	0	(0)	0
	MISO	(1,753)	(2,118)	365		SOUTHIMP	0	3	(3)
	SOUTHEXP	0	(15)	15	MECS		31	233	(202)
	SOUTHIMP	0	23	(23)		IMO	0	293	(293)
CPLE		671	229	441		MISO	31	(221)	252
	CPLEEXP	0	(104)	104		SOUTHEXP	0	(6)	6
	CPLEIMP	0	1	(1)		SOUTHIMP	0	167	(167)
	DUKEXP	0	(7)	7	NEPT		(1,398)	(1,398)	0
	DUKIMP	0	28	(28)		NEPTUNE	(1,398)	(1,398)	0
	NCMPAIMP	0	266	(266)	NIPS		(2,814)	(1)	(2,813)
	SOUTHEXP	(616)	(131)	(485)		MISO	(2,814)	(5)	(2,809)
	SOUTHIMP	1,287	176	1,111		SOUTHIMP	0	5	(5)
CPLW		(201)	0	(201)	NYIS		(1,547)	(1,596)	49
	SOUTHEXP	(243)	(0)	(243)		IMO	0	1	(1)
	SOUTHIMP	42	0	42		NYIS	(1,547)	(1,597)	50
CWLP		(13)	0	(13)	TVA		2,105	157	1,948
	MISO	(13)	0	(13)		SOUTHEXP	(1,032)	(155)	(877)
DUK		642	502	140		SOUTHIMP	3,136	311	2,825
	DUKEXP	0	(227)	227	WEC		915	(166)	1,081
	DUKIMP	0	124	(124)		MISO	915	(177)	1,093
	NCMPAIMP	0	137	(137)		SOUTHEXP	0	(1)	1
	SOUTHEXP	(262)	(266)	4		SOUTHIMP	0	12	(12)
	SOUTHIMP	904	734	170	Grand Total		(6,747)	(6,732)	(15)
HUDS		(461)	(461)	0					
	HUDSONTP	(461)	(461)	0					

Table 9-24 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-23. Table 9-24 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-24 shows that in the first three months of 2019, 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 a path that entered the PJM energy market at the MECS Interface (293 GWh). In the first three months of 2019, there were no net 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.

Table 9-24 Net scheduled and actual flows by interface pricing point and interface (GWh): January through March, 2019

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(104)	104	NEPTUNE		(1,398)	(1,398)	0
	CPLE	0	(104)	104		NEPT	(1,398)	(1,398)	0
CPLEIMP		0	1	(1)	NYIS		(1,547)	(1,597)	50
	CPLE	0	1	(1)		NYIS	(1,547)	(1,597)	50
DUKEXP		0	(235)	235	SOUTHEXP		(3,982)	(843)	(3,139)
	CPLE	0	(7)	7		ALTE	0	(1)	1
	DUK	0	(227)	227		ALTW	0	(5)	5
DUKIMP		0	152	(152)		CIN	0	(15)	15
	CPLE	0	28	(28)		CPLE	(616)	(131)	(485)
	DUK	0	124	(124)		CPLW	(243)	(0)	(243)
HUDSONTP		(461)	(461)	0		DUK	(262)	(266)	4
	HUDS	(461)	(461)	0		IPL	0	(3)	3
IMO		0	362	(362)		LGEE	(1,829)	(260)	(1,569)
	ALTE	0	62	(62)		MEC	0	(0)	0
	CIN	0	2	(2)		MECS	0	(6)	6
	IPL	0	4	(4)		TVA	(1,032)	(155)	(877)
	MECS	0	293	(293)		WEC	0	(1)	1
	NYIS	0	1	(1)	SOUTHIMP		8,518	2,387	6,131
LINDENVFT		(654)	(654)	0		ALTE	0	4	(4)
	LIND	(654)	(654)	0		AMIL	0	642	(642)
MISO		(7,224)	(4,746)	(2,477)		CIN	0	23	(23)
	ALTE	(991)	(653)	(339)		CPLE	1,287	176	1,111
	ALTW	(655)	(5)	(650)		CPLW	42	0	42
	AMIL	(497)	(62)	(435)		DUK	904	734	170
	CIN	(1,753)	(2,118)	365		IPL	0	0	(0)
	CWLP	(13)	0	(13)		LGEE	3,148	308	2,840
	IPL	(308)	(130)	(178)		MEC	0	3	(3)
	MEC	(1,139)	(1,375)	236		MECS	0	167	(167)
	MECS	31	(221)	252		NIPS	0	5	(5)
	NIPS	(2,814)	(5)	(2,809)		TVA	3,136	311	2,825
	WEC	915	(177)	1,093		WEC	0	12	(12)
NCMPAIMP		0	403	(403)	Grand Total		(6,747)	(6,732)	(15)
	CPLE	0	266	(266)					
	DUK	0	137	(137)					

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. 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. Loop flows also have poorly understood impacts on nonmarket areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and nonmarket areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (nonmarket areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. The Commission required access to NERC Tag data. In addition to the Tag data, actual tie line data, dynamic schedule and pseudo-tie data are required in order to analyze the differences between actual and scheduled transactions. ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions.[29]

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data include the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Complete tag data include the identity of the specific market participants. FERC Order No. 771 required access to NERC Tag data for the Commission, regional transmission organizations, independent system operators and market monitoring units.[30]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. The available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

Dynamic Schedule and Pseudo-Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo-ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo ties differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo tie transactions are not required to be tagged. Pseudo-tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

29 It is requested that all data be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.
30 141 FERC ¶ 61,235 (2012).

Area Control Error (ACE) Data

Area Control Error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, but, equally important, requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket balancing authorities provide only the expected peak load on their individual web sites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU recommends, that in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

PJM and MISO Interface Prices

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.

Under the PJM/MISO Joint Operating Agreement, the two RTOs mutually determine a set of transmission facilities on which both RTOs have an impact, and therefore jointly operate to those constraints. These jointly controlled facilities are M2M (Market to Market) flowgates. When a M2M constraint binds, PJM's LMP calculations at the buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. MISO's LMP calculations at the buses that make up MISO's PJM interface pricing point are based on the MISO model's distribution factors of the selected buses to the binding M2M constraint and MISO's shadow price of the binding M2M constraint.

Prior to June 1, 2014, the PJM interface definition for MISO consisted of nine buses located near the middle of the MISO system and not at the border between the RTOs. The interface definitions led to questions about the level of congestion included in interchange pricing.[31]

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie line flows between PJM and MISO occurred on 10 ties composed of MISO and PJM monitored facilities. On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

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

In the first three months of 2019, the direction of flow was consistent with price differentials in 54.2 percent of the hours. Table 9-25 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Figure 9-5 shows the underlying variability in prices calculated on a daily hourly average basis. 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 (Table 9-29).

Table 9-25 PJM and MISO flow based hours and price differences: January through March, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	1,171	$5.59
	Consistent Flow (PJM to MISO)	1,170	$5.59
	Inconsistent Flow (MISO to PJM)	1	$14.09
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	988	$5.77
	Consistent Flow (MISO to PJM)	1	$18.83
	Inconsistent Flow (PJM to MISO)	987	$5.75
	No Flow	0	$0.00

31 See "LMP Aggregate Definitions" (December 12, 2018) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.ashx>. PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): January through March, 2019

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

In the first three months of 2019, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 1,171 hours (54.2 percent of all hours), and was inconsistent with price differentials in 988 hours (45.8 percent of all hours). Table 9-26 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 988 hours where flows were in a direction inconsistent with price differences, 744 of those hours (75.3 percent) had a price difference greater than or equal to $1.00 and 243 of those hours (24.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $227.86. Of the 1,171 hours where flows were consistent with price differences, 906 of those hours (77.4 percent) had a price difference greater than or equal to $1.00 and 251 of all such hours (21.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $575.74.

Table 9-26 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through March, 2019

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	988	100.0%	1,171	100.0%
$1.00	744	75.3%	906	77.4%
$5.00	243	24.6%	251	21.4%
$10.00	127	12.9%	123	10.5%
$15.00	71	7.2%	63	5.4%
$20.00	53	5.4%	39	3.3%
$25.00	33	3.3%	31	2.6%
$50.00	14	1.4%	14	1.2%
$75.00	8	0.8%	7	0.6%
$100.00	5	0.5%	4	0.3%
$200.00	1	0.1%	2	0.2%
$300.00	0	0.0%	2	0.2%
$400.00	0	0.0%	2	0.2%
$500.00	0	0.0%	2	0.2%

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.[32]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. Prior to May 1, 2017, PJM used two buses within NYISO to calculate the PJM/NYIS interface pricing point LMP. The NYISO uses proxy buses to calculate interface prices with neighboring balancing authorities. A proxy bus is a single bus, located outside the NYISO footprint, which represents generation and load in a neighboring balancing authority area. The NYISO models imports from PJM as generation at the Keystone proxy bus, delivered to the NYISO reference bus with the assumption that 32 percent of the flow will enter the NYISO across the free flowing A/C ties, 32 percent will enter the NYISO across the Ramapo PARs, 21 percent will enter the NYISO across the ABC PARs and 15 percent will enter the NYISO across the J/K PARs. The NYISO models exports to PJM as being delivered to load at the Keystone proxy bus, sourced from the NYISO reference bus with the assumption that 32 percent of the flow will enter PJM across the free flowing A/C ties, 32 percent will enter PJM across the Ramapo PARs, 21 percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

32 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

The PJM/NYIS interface definition using two buses was created to include the impact of the ConEd wheeling agreement. The ConEd wheeling agreement ended on May 1, 2017. The end of the wheeling agreement meant that the expected actual power flows would change and therefore the definition of the interface price needed to change. Effective May 1, 2017, PJM replaced the old PJM/NYIS interface price definition. The new PJM/NYIS interface price is based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

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

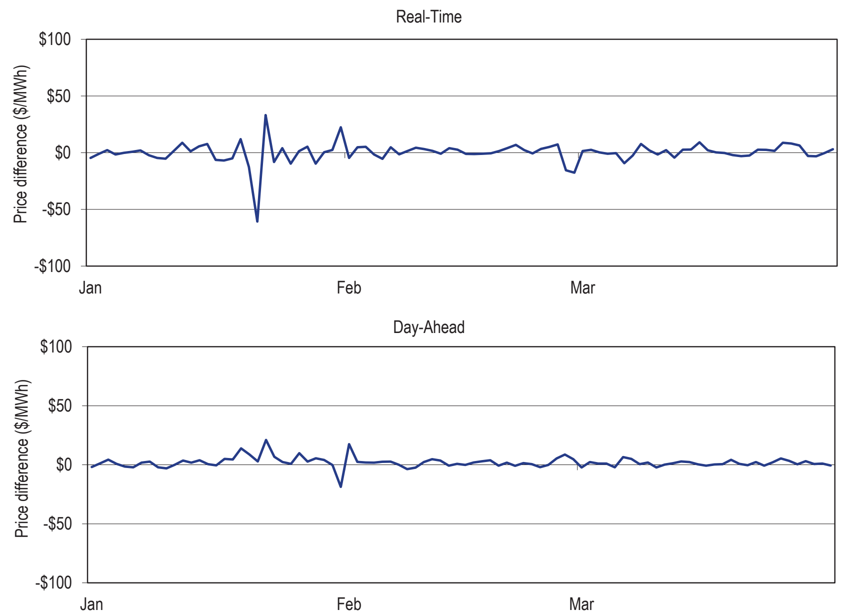
In the first three months of 2019, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. The direction of flow was consistent with price differentials in 60.0 percent of the hours in the first three months of 2019. Table 9-27 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction. Figure 9-6 shows the underlying variability in prices calculated on a daily hourly average basis. 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 (Table 9-29).

Table 9-27 PJM and NYISO flow based hours and price differences: January through March, 2019[33]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	1,285	$8.60
	Consistent Flow (PJM to NYIS)	1,204	$8.70
	Inconsistent Flow (NYIS to PJM)	81	$7.11
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	874	$12.08
	Consistent Flow (NYIS to PJM)	105	$5.88
	Inconsistent Flow (PJM to NYIS)	769	$12.93
	No Flow	0	$0.00

33 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Figure 9-6 Price differences (NY/PJM proxy - PJM/NYIS Interface): January through March, 2019



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

In the first three months of 2019, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 1,309 hours (60.0 percent of all hours), and was inconsistent with price differences in 850 hours (40.0 percent of all hours). Table 9-28 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 850 hours where flows were in a direction inconsistent with price differences, 731 of those hours (86.0 percent) had a price difference greater than or equal to $1.00 and 384 of all those hours (45.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $461.20. Of the 1,309 hours where flows were consistent with price differences, 1,170 of those hours

(89.4 percent) had a price difference greater than or equal to $1.00 and 565 of all such hours (43.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $300.05.

Table 9-28 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through March, 2019

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	850	100.0%	1,309	100.0%
$1.00	731	86.0%	1,170	89.4%
$5.00	384	45.2%	565	43.2%
$10.00	225	26.5%	259	19.8%
$15.00	151	17.8%	158	12.1%
$20.00	112	13.2%	106	8.1%
$25.00	94	11.1%	81	6.2%
$50.00	46	5.4%	31	2.4%
$75.00	31	3.6%	18	1.4%
$100.00	13	1.5%	7	0.5%
$200.00	2	0.2%	1	0.1%
$300.00	1	0.1%	1	0.1%
$400.00	1	0.1%	0	0.0%
$500.00	0	0.0%	0	0.0%

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 Table 9-29, including average prices and measures of variability.

Table 9-29 PJM, NYISO and MISO border price averages: January through March, 2019[34]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$30.22	$26.61	$30.63	$26.92
	ISO Price at PJM Border	$30.41	$27.00	$32.62	$28.18
	Difference at Border (PJM-ISO)	($0.19)	($0.39)	($1.99)	($1.26)
	Average Absolute Value of Interval Difference at Border	$40.11	$32.28	$4.80	$3.70
	Sign Changes per Day	41.8	45.1	3.0	3.3
Standard Deviation	PJM Price at ISO Border	$37.97	$24.63	$15.42	$8.29
	ISO Price at PJM Border	$24.82	$24.03	$15.54	$10.06
	Difference at Border (PJM-ISO)	$42.05	$33.04	$5.93	$4.53

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. The flows were consistent with price differentials in 80.7 percent of the hours in the first three months of 2019. Table 9-30 shows the number of hours and average hourly price differences between the PJM/NEPT Interface and the NYIS/Neptune bus based on LMP differences and flow direction.

34 Effective April 1, 2018, PJM implemented 5 minute LMP settlements in the Real-Time Energy Market. The sign changes per day represented in this table reflect the number of intervals where the sign changed per day. For the Real-Time Energy Market, there are 288 five minute intervals. For the Day Ahead Market there are 24 hourly intervals.

Table 9-30 PJM and NYISO flow based hours and price differences (Neptune): January through March, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	1,742	$13.46
	Consistent Flow (PJM to NYIS)	1,742	$13.46
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	417	$13.29
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	417	$13.29
	No Flow	0	$0.00

To move power from PJM to NYISO using the Neptune Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC Line ("Out Service") and another transmission service reservation is required on the Neptune HVDC line ("Neptune Service").[35] The PJM Out Service is covered by normal PJM OASIS business operations.[36] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder does not elect to voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On March 31, 2019, the rate for the nonfirm service released by default was $10 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

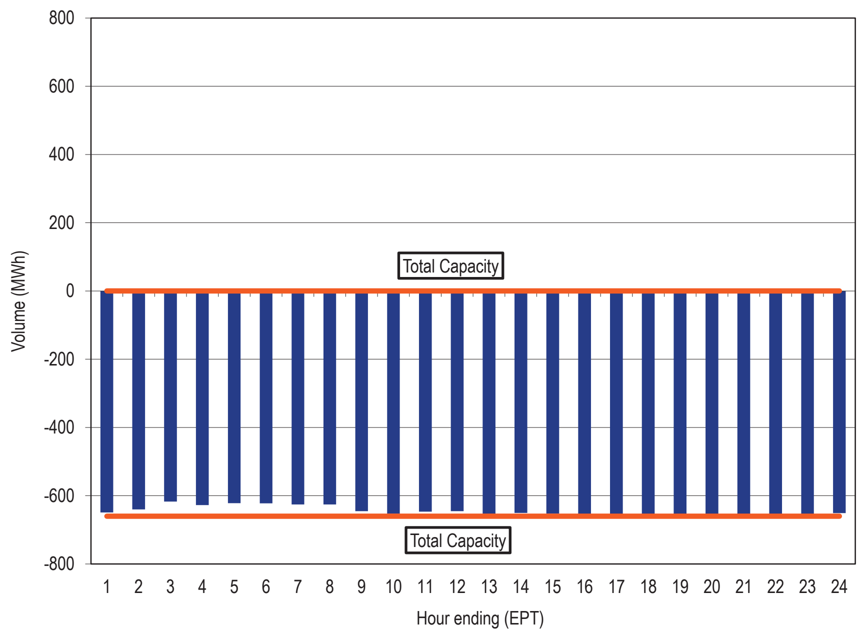
Table 9-31 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July, 2007. Table 9-31 shows that in the first three months of 2019, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-7 shows the hourly average flow across the Neptune Line for the first three months of 2019.

35 See OASIS "PJM Business Practices for Neptune Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/neptune-oasis-Business-practices-doc-clean.ashx>.
36 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 7 (December 19, 2018) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Table 9-31 Percent of scheduled interchange across the Neptune line by primary rights holder: July 2007 through March 2019

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
June	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
July	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
August	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
September	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
October	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Figure 9-7 Neptune hourly average flow: January through March, 2019



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 315 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). The flows were consistent with price differentials in 78.0 percent of the hours in the first three months of 2019. Table 9-32 shows the number of hours and average hourly price differences between the PJM/LIND Interface and the NYIS/Linden bus based on LMP differences and flow direction.

Table 9-32 PJM and NYISO flow based hours and price differences (Linden): January through March, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	1,684	$11.00
	Consistent Flow (PJM to NYIS)	1,684	$11.00
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	475	$24.57
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	475	$24.57
	No Flow	0	$0.00

To move power from PJM to NYISO on the Linden VFT Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT ("Out Service") and another transmission service reservation is required on the Linden VFT ("Linden VFT Service").[37] The PJM Out Service is covered by normal PJM OASIS business operations.[38] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule

37 See OASIS "PJM Business Practices for Linden VFT Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>.

38 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 7 (December 19, 2018) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

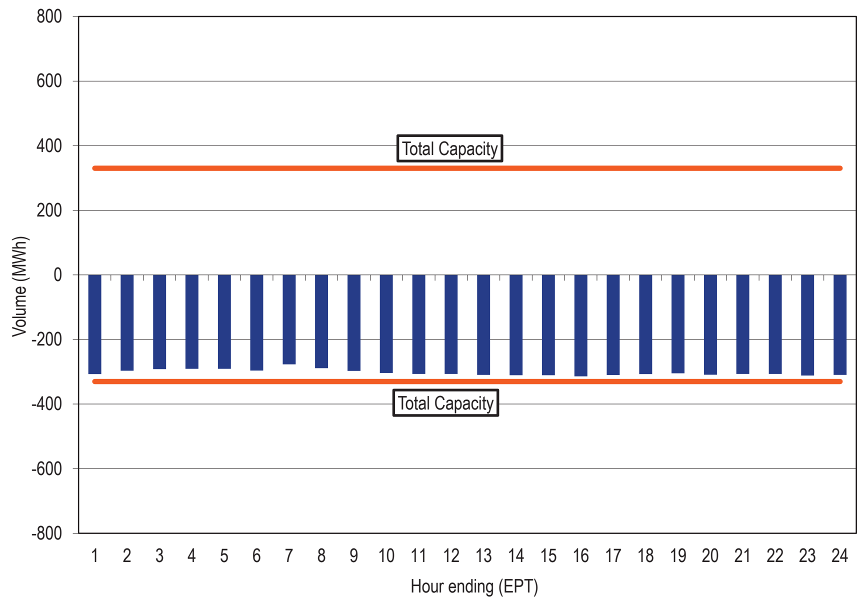
Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On March 31, 2019, the rate for the nonfirm service released by default was $6.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-33 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-33 shows that in the first three months of 2019, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-8 shows the hourly average flow across the Linden VFT Line for the first three months of 2019.

Table 9-33 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through March 2019

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	100.00%	100.00%	
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
June	NA	100.00%	100.00%	100.00%	100.00%	27.27%	100.00%	100.00%	100.00%	100.00%	
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	100.00%	100.00%	
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	100.00%	100.00%	
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	100.00%	100.00%	
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%	

Figure 9-8 Linden hourly average flow: January through March, 2019[39]



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

Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) Line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (Con Ed) 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 had only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of nonfirm withdrawal rights). The flows were consistent with price differentials in 75.4 percent of the hours in the first three months of 2019. Table 9-34 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-34 PJM and NYISO flow based hours and price differences (Hudson): January through March, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	1,628	$10.78
	Consistent Flow (PJM to NYIS)	1,628	$10.78
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	531	$18.83
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	531	$18.83
	No Flow	0	$0.00

To move power from PJM to NYISO on the Hudson Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson Line ("Out Service") and another transmission service reservation is required on the Hudson Line ("Hudson Service").[40] The PJM Out Service is covered by normal PJM OASIS business operations.[41] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

Hudson Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by scheduled on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On March 31, 2019, the rate for the nonfirm service released by default was $10 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-35 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-35 shows that in the first three months of 2019, the primary rights holder was responsible for less than 100 percent of the scheduled interchange across the Hudson Line in all months. Figure 9-9 shows the hourly average flow across the Hudson Line for the first three months of 2019.

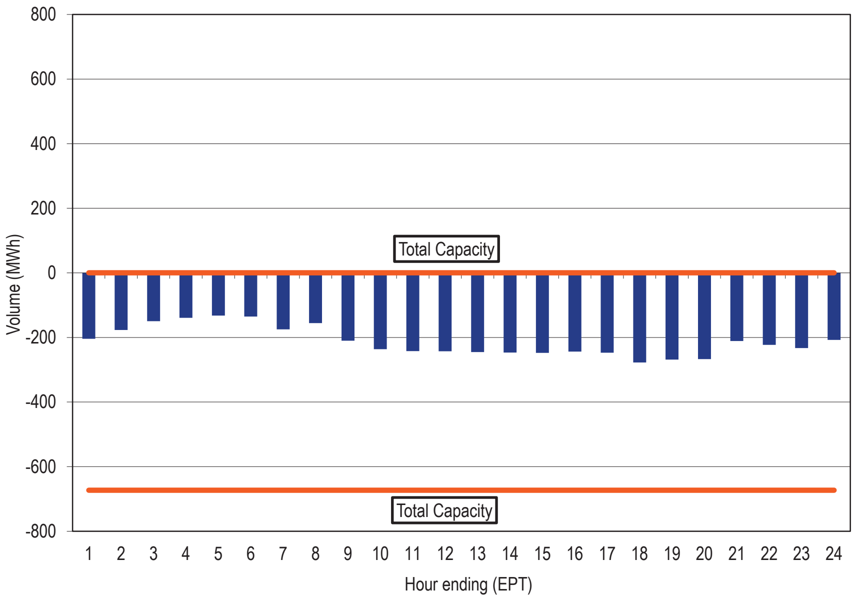
40 See OASIS "PJM Business Practices for Hudson Transmission Service,"<http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.

41 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 7 (December 19, 2018) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Table 9-35 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through March 2019

	2013	2014	2015	2016	2017	2018	2019
January	NA	51.22%	16.27%	100.00%	NA	24.44%	52.21%
February	NA	49.00%	14.67%	NA	NA	23.25%	77.12%
March	NA	40.40%	71.88%	NA	NA	9.55%	72.40%
April	NA	100.00%	100.00%	NA	NA	15.13%	
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%	
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%	
July	100.00%	18.51%	84.34%	NA	NA	16.26%	
August	100.00%	75.17%	65.48%	NA	NA	19.24%	
September	100.00%	75.31%	78.73%	NA	NA	22.90%	
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%	
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	

Figure 9-9 Hudson hourly average flow: January through March, 2019



Interchange Activity During High Load Hours

The PJM metered system peak load during the first three months of 2019 was 134,060 MW in the HE 0700 on January 31, 2019. PJM was under a cold weather alert in that hour. PJM did not make any emergency energy purchases or sales in that hour. PJM was a net scheduled exporter of energy in all but two hours on January 31, 2019 (HE 0400 and HE 0600), with average hourly scheduled exports of 1,143 MW. During HE 0700 on January 31, 2019, PJM had net scheduled exports of 1,077 MW and net metered actual exports of 1,668 MW. Net transaction exports during this time were consistent with the price differences between PJM and MISO, but were inconsistent with price differences between PJM and the NYISO interfaces (NYIS, Neptune, Linden and Hudson). During the month of January 2019, PJM was a net scheduled exporter of energy in 740 of the 744 hours. During January 2019, the average hourly scheduled interchange was -3,600 MW (representing 3.7 percent of the average hourly load of 97,319 MW in January 2019).

Operating Agreements with Bordering Areas

To improve reliability and reduce potential seams issues, PJM and its neighbors have developed operating agreements, including: operating agreements with MISO and the NYISO; a reliability agreement with TVA; an operating agreement with Duke Energy Progress, Inc.; a reliability coordination agreement with VACAR South; a balancing authority operations agreement with the Wisconsin Electric Power Company (WEC); and a Northeastern planning coordination protocol with NYISO and ISO New England.

Table 9-36 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-36 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA	PJM-DEP	PJM-VACAR	PJM-WEP	Northeastern Protocol
Data Exhange							
Real-Time Data	YES	YES	YES	YES	YES	YES	NO
Projected Data	YES	YES	YES	YES	NO	NO	NO
SCADA Data	YES	YES	YES	YES	NO	NO	NO
EMS Models	YES	YES	YES	YES	NO	NO	YES
Operations Planning Data	YES	YES	YES	YES	NO	NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO	NO	YES
Near-Term System Coordination							
Operating Limit Violation Assistance	YES	YES	YES	YES	YES	NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES	NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES	NO	NO
Outage Coordination	YES	YES	YES	YES	YES	NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO	NO	YES
Congestion Management Process							
ATC Coordination	YES	YES	YES	YES	NO	NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO	NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO	NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	YES - Dynamic Schedule	NO	NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO	YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement
PJM-NYISO = New York ISO/PJM Joint Operating Agreement
PJM-TVA = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA)
PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement
PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement
PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC
Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[42]

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.[43]

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 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP. Prior to June 1, 2017, MISO used all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[44] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.[45]

An operating entity is an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads and other operating entities.[46] Coordinated flowgates are identified to determine which flowgates an operating entity affects significantly. This set of flowgates may then be used in the congestion management process. An operating entity will conduct sensitivity studies to determine which flowgates are significantly affected by the flows of the operating entity's control zones (historic control areas that existed in the IDC). An operating entity identifies these flowgates by performing five studies to determine which flowgates the operating entity will monitor and help control. These studies include generation to load distribution factor studies, transfer distribution factor analysis and an external asynchronous resource study. An operating entity may also specify additional flowgates that have not passed any of the five

42 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/directory/merged-tariffs/miso-joa.pdf>.
43 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.

44 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.
45 See "Joint and Common Market: MISO-PJM Interface Pricing Update" (November 15, 2016) <http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20161115/20161115-item-03a-interface-pricing-post-implementation.ashx>.
46 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/directory/merged-tariffs/miso-joa.pdf>.

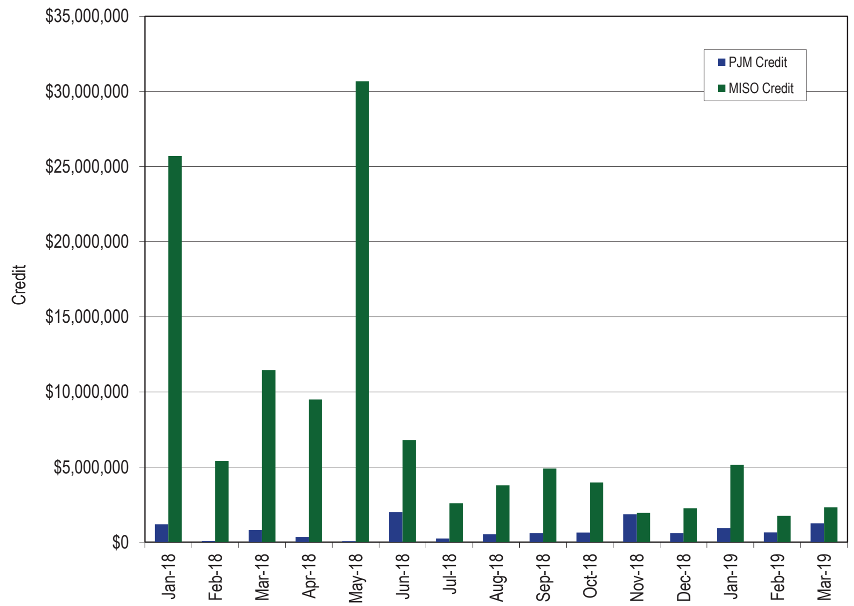
studies to be coordinated flowgates where the operating entity expects to use the TLR process to manage congestion.[47] A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of January 1, 2019, PJM had 137 flowgates eligible for M2M (Market to Market) coordination. In the first three months of 2019, PJM added five flowgates and deleted seven flowgates, leaving 135 flowgates eligible for M2M coordination as of March 31, 2019. As of January 1, 2019, MISO had 239 flowgates eligible for M2M coordination. In the first three months of 2019, MISO added 16 flowgates and deleted 26 flowgates, leaving 229 flowgates eligible for M2M coordination as of March 31, 2019.

The firm flow entitlement (FFE) represents the amount of historic 2004 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 nonmonitoring 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 nonmonitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE. In the first three months of 2019, market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and MISO.

47 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/directory/merged-tariffs/miso-joa.pdf>.

Figure 9-10 PJM/MISO credits for coordinated congestion management: January 2018 through March 2019[48]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[49]

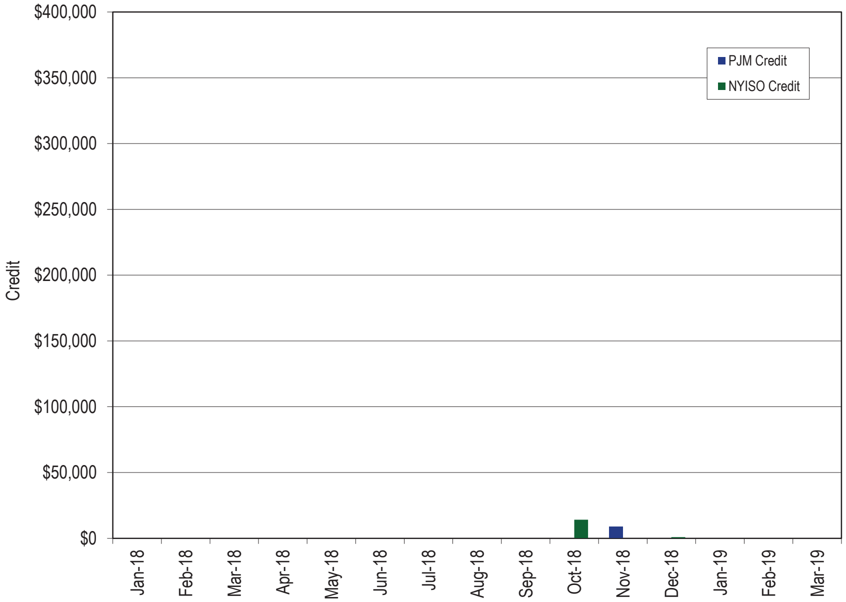
The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders.

In the first three months of 2019, market to market operations did not result in NYISO and PJM redispatching units to control congestion on M2M flowgates. Therefore, there was no exchange of payments for redispatch in the first three months of 2019. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

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

49 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (June 21, 2017) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

Figure 9-11 PJM/NYISO credits for coordinated congestion management (flowgates): January 2018 through March 2019[50]

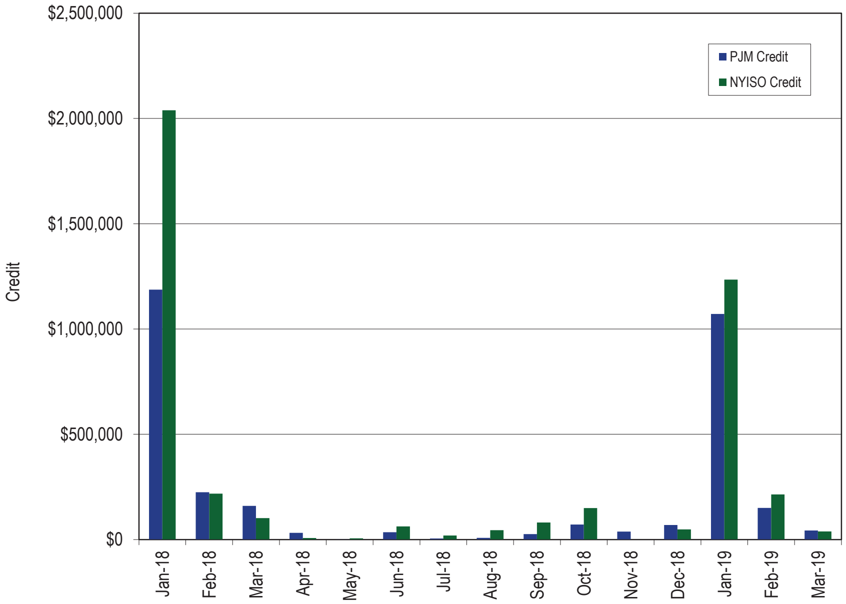


The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the PARs that are located at the PJM/NYIS border. This real-time coordination results in an 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.[51] For each M2M flowgate, a PAR settlement will occur for each interval during coordinated operations. The PAR settlements are determined based on whether the measured real-time flow on each of the 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. Effective May 1, 2017, coincident with the termination of the ConEd wheel, PJM and NYISO began M2M coordination at all of the PARs along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In the first three months of 2019, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. Figure 9-12 shows the PAR credits for coordinated congestion management between PJM and NYISO. The large increase in PAR credits in January 2018 and January 2019 was due to system operations coordination during the extreme temperatures in the first week of January 2018 and in January 2019.

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

51 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (June 21, 2017) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

Figure 9-12 PJM/NYISO credits for coordinated congestion management (PARs): January 2018 through March 2019[52]



PJM and TVA Joint Reliability Coordination Agreement (JRCA)[53]

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for the exchange of information and the implementation of reliability and efficiency protocols between TVA and PJM. The agreement also provides for the management of congestion and arrangements for both near-term and long-term system coordination. Under the JRCA, PJM and TVA honor constraints on the other's flowgates in their Available Transmission Capability (ATC) calculations. Market flows are calculated on reciprocal flowgates. When a constraint occurs on a reciprocal flowgate within TVA, PJM has the option to redispatch generation to reduce market flow, and therefore alleviate the constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. The agreement remained in effect in the first three months of 2019.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[54]

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.[55] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy Carolinas Inc., now a subsidiary of Duke, changed its name to Duke Energy Progress (DEP).

The PJM/DEP JOA states that the Marginal Cost Proxy Method (MCPM) will be used in the determination of the CPLEIMP and CPLEEXP interface price. Section 2.6A (2) of the PJM Tariff describes the process of calculating the interface price under the MCPM. Under the MCPM, PJM compares the individual bus LMP (as calculated by PJM) for each DEP generator in the PJM model with a telemetered output greater than zero MW to the marginal cost for that generator.

For the CPLEIMP price (imports to PJM), PJM uses the lowest LMP of any generator bus in the DEP balancing authority area, with an output greater than zero MW that has an LMP less than its marginal cost for each five minute interval. If no generator with an output greater than zero MW has an LMP less than its marginal cost, then the import price is the average of the bus LMPs for the set of generators in the DEP area with an output greater than

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

53 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority" (October 15, 2014) <http://www.pjm.com/~/media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>.

54 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc." (December 3, 2014) <http://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>.

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

zero MW that PJM determines to be the marginal units in the DEP area for that five minute interval. PJM determines the marginal units in the DEP area by summing the output of the units serving load in the DEP area in ascending order by the units' marginal costs until the sum equals the real-time load in the DEP area. Units in the DEP area with marginal costs at or above that of the last unit included in the sum are the marginal units for the DEP area for that interval.

PJM calculates the CPLEEXP price for exports from PJM to DEP as the highest LMP of any generator bus in the DEP area with an output greater than zero MW (excluding nuclear and hydro units) that has an LMP greater than its marginal cost in the 5 minute interval.[56] If no generator with an output greater than zero MW has an LMP greater than its marginal cost, then the export price will be the average of the bus LMPs for the set of generators with an output greater than zero MW that PJM determines to the be marginal units in the same manner as described for the CPLEIMP interface price. The hourly integrated import and export prices are the average of all of the 5 minute intervals in each hour.

The MCPM calculation is based on the DEP units modeled in the PJM market that have an output greater than zero, and only uses the units whose output exceeds the reported DEP real-time load. When new units are added to the DEP footprint, and existing units in the DEP footprint retire, PJM does not have complete data to calculate the interface price. These new units can impact the interface price in several ways. By not having the additional units modeled, these units cannot be considered to be marginal units, and therefore cannot set price. For the import price, if the PJM calculated LMP of one of the new units were to be lower than any currently modeled unit, then PJM's CPLEIMP pricing point would be lower, and PJM would pay less for imports. If the PJM calculated LMP of one of the new units were to be higher than any currently modeled unit, then PJM's CPLEEXP pricing point would be higher, and PJM would receive more for exports.

56 The MMU has objected to the omission of nuclear and hydro units from the calculation. This omission is not included in the definition of the MCPM interface pricing method in the PJM Tariff, but is included as a special condition in the PJM/DEP JOA. The MMU does not believe it is appropriate to exclude these units from the calculation as these units could be considered marginal and affect the prices.

Not maintaining a current set of units in the DEP footprint in PJM's network model limits PJM's ability to recognize which units are marginal and it is often not possible to calculate the CPLEIMP and CPLEEXP interface prices using the MCPM. By not maintaining a complete set of units in the DEP footprint, the reported output of the modeled units are often insufficient to cover the reported real-time load, and therefore no units are considered marginal. When this occurs, the MMU believes that the CPLEIMP and CPLEEXP pricing points should revert to the SOUTHIMP and SOUTHEXP interface prices, but this has not happened. When this occurs, PJM uses the high-low interface pricing method as described in Section 2.6A (1) of the PJM Tariff. The MMU does not believe that this is appropriate, and does not see the basis for this approach in either the PJM Tariff or the PJM/DEP JOA.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[57] On October 3, 2014, Duke Energy Progress (DEP) and PJM submitted revisions to the JOA to include a new Appendix B, update references to DEP's current legal name, and incorporate other revisions.[58] The MMU submitted a protest to this filing noting that the existing JOA depends on the specific characteristics of PEC as a standalone company, and the assumptions reflected in the current JOA no longer apply under the DEP joint dispatch agreement.[59] As noted in the 2010 filing, "the terms and conditions of the bilateral agreement among PEC and PJM are grounded in an appreciation of their systems as they exist at the time of the effective date of the JOA, but they fully expect that evolving circumstances, protocols and requirements will require that they negotiate, in good faith, a response to such changes."[60] The joint dispatch agreement changed the unique operational relationship that existed when the congestion management protocol was established. However, the merged company has not engaged in discussions with PJM as to whether the congestion management protocol that was "tailored to their [PJM and PEC] unique operational relationship" is still appropriate, or whether the

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

congestion management protocol needs to be revised. The existing JOA does not apply to the merged company and should be terminated.

Article 14 of the JOA provides details of the PJM/DEP congestion management agreement (CMA). The purpose of the CMA is to allow "DEP to quickly respond to the LMP values sent by PJM to DEP. This quick response will help manage the congestion on the PJM transmission system by maintaining flows within established limits and stabilizing PJM LMP values, and will help reduce the need to use the TLR process to relieve the congestion by maintaining power flows within established reliability limits." Congestion is managed by using a dynamic schedule between CPLE and PJM. DEP responds to the dynamic pricing signal sent by PJM by increasing generation, which creates energy flow in the direction from CPLE to PJM or by decreasing generation, which creates energy flow in the direction from PJM to CPLE. The dynamic schedule calls for more DEP generation when the DEP marginal cost of online generation is less than the CPLE LMP, and it calls for less DEP generation when the DEP marginal cost exceeds the CPLE LMP. The economic energy flow on the dynamic schedule reduces congestion.

The amount of congestion relief is limited by the amount of energy that can flow on the dynamic schedule. Several factors determine this limit, including: the physical limitations of DEP's units; ATC limits on the transmission path between CPLE and PJM; the actual confirmed transmission acquired in advance by DEP. Section 14.4.1 of the JOA states that:

> The transmission service used on the DEP transmission system to support the process described in this Article will be a non-firm point to point reservation from DEP to PJM made by DEP. The Dynamic Schedule will be limited to the point to point reservation. The transmission service used on the PJM transmission system will be network secondary service.

In the first three months of 2019, DEP acquired the required transmission service in only 13 of the 2,159 hours (0.6 percent of all hours), with an average capacity of approximately 182 MW. At most, DEP could have increased their generation to help manage constraints via a sale of power to PJM 0.6 percent of the time in the first three months of 2019, and the maximum redispatch would have been only 182 MW, on average.

A CMA that can only be used in 0.6 percent of all hours is not an effective approach to congestion management. For that reason and based on the significant flaws in the agreement, the MMU recommends that PJM immediately provide the required 12-month notice to DEP to unilaterally terminate the Joint Operating Agreement.

PJM and VACAR South Reliability Coordination Agreement[61]

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), DEP, 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 which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement remained in effect in the first three months of 2019.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[62]

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement remained in effect in the first three months of 2019.

61 See "PJM-VACAR South RC Agreement" (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.
62 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, L.L.C." (July 20, 2013) <http://www.pjm.com/~/media/documents/agreements/balancing-authority-operations-coordination-agreement.ashx>.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[63]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement remained in effect in the first three months of 2019.

Interface Pricing Agreements with Individual Balancing Authorities

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

The PJM/DEP JOA allows for the CPLEIMP and CPLEEXP interface pricing points to be calculated using the Marginal Cost Proxy Pricing method.[64] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the high-low pricing method as defined in Section 2.6A (1) of the PJM Tariff.

Table 9-37 shows the real-time LMP calculated per the PJM/DEP JOA and the high/low pricing method used by Duke and NCMPA for the first three months of 2019. The values shown in Table 9-37 are the average LMP over only the hours in the first three months of 2019 where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.19 with Duke to $0.38 with NCMPA. This means that under the specific interface pricing agreements, transactions settling at the Duke interface price would receive, on average, $0.19 less for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first three months of 2019, market participants received $23,962 less for importing energy using this pricing point than they would have if they were to have received the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $0.59 with Duke to $3.04 with PEC.[65] This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would pay, on average, $3.04 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point. In the first three months of 2019, market participants paid $276,633 more for exporting energy using this pricing point than they would have if they were to have paid the SouthEXP pricing point.

Table 9-37 Real-time LMP comparison for Duke, PEC and NCMPA: January through March, 2019

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$29.66	$27.03	$29.86	$26.43	($0.19)	$0.59
PEC	$27.89	$35.16	$27.81	$32.12	$0.08	$3.04
NCMPA	$26.76	NA	$26.38	NA	$0.38	NA

Table 9-38 shows the day-ahead LMP calculated per the PJM/DEP JOA and the high/low pricing method used by Duke and NCMPA for the first three months of 2019. The values shown in Table 9-38 are the average LMP over only the hours in the first three months of 2019 where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from $0.53 with PEC to $0.60 with NCMPA. This means that under the specific interface pricing agreements, transactions settling at the NCMPA interface price would receive, on average, $0.60 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first three months of 2019, market participants received $273,303 more for importing energy using this pricing point than they would have if they were to have received the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP was $1.23 at the PEC interface. This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would pay, on average, $1.23 more for exporting energy from PJM than if they were to pay the SouthEXP pricing point. In the first three months of

63 See "Northeastern ISO/RTO Planning Coordination Protocol" (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.
64 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).
65 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

2019, market participants paid $151,464 more for exporting energy using this pricing point than they would have if they were to have paid the SouthEXP pricing point.

Table 9-38 Day-ahead LMP comparison for Duke, PEC and NCMPA: January through March, 2019

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$32.59	NA	$32.04	NA	$0.54	NA
PEC	$28.56	$32.49	$28.04	$31.26	$0.53	$1.23
NCMPA	$28.43	NA	$27.83	NA	$0.60	NA

It is not clear that agreements between PJM and neighboring external entities, in which those entities receive some of the benefits of the PJM LMP market without either integrating into an LMP market or applying LMP internally, are in the best interest of PJM's market participants. In the case of the DEP JOA for example, the merger between Progress and Duke has resulted in a single, combined entity where one part of that entity (Duke Energy Progress) is engaged in congestion management with PJM while the other part of the entity (Duke) is not.

Interchange Transaction Issues

Hudson Transmission Partners (HTP) and Linden VFT Requests to Convert Firm Transmission Withdrawal Rights (FTWR) to NonFirm Transmission Withdrawal Rights (NFTWR)

In 2014, cost allocations for RTEP projects included the Bergen-Linden Corridor (BLC) project. Using the solution-based DFAX cost allocation method, PJM initially allocated BLC's estimated costs: $720 million to Con Edison; $103 million to HTP; $10 million to Linden VFT; no costs to Neptune; and $88 million to PSEG. To avoid its share of the cost allocation, Con Edison elected to terminate its 1,000 MW of long-term firm transmission service (the Con Ed Wheel) effective May 1, 2017. PJM reallocated the costs: $634 million to HTP; $132 million to Linden VFT; and the remaining $128 million to PSEG. The Commission denied complaints about the cost allocation, ruling that PJM applied the Commission accepted regional cost allocation method.[66]

In June 2017, HTP and Linden separately initiated the process to amend their interconnection service agreements to reflect the conversion of FTWRs to NFTWRs in an effort to avoid paying their allocated share of the RTEP cost allocations. On June 2, 2017, HTP sent a letter to PJM and PSEG requesting that their original Interconnection Service Agreement (ISA) be amended to reflect the conversion of their 320 MW of FTWRs to NFTWRs. On June 22, 2017, PSEG notified PJM and HTP that it did not agree to the ISA amendment. Because PSEG did not agree to the amendment to the ISA, HTP requested that PJM file an unexecuted amended interconnection service agreement with the Commission to convert their FTWRs to NFTWRs. Similarly, at the request of Linden VFT, PJM also filed an unexecuted amended ISA to convert their FTWRs to NFTWRs.[67] On September 8, 2017, the Commission rejected the amended ISAs and instituted a proceeding "to examine the justness and reasonableness of HTP being unable to convert its Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights." On December 15, 2017, the Commission found that the exiting HTP and Linden ISA's are unjust and unreasonable insofar as they do not permit HTP and Linden to convert their FTWRs to NFTWRs and ordered PJM to amend the existing ISAs to reflect the conversion of FTWRs to NFTWRs.[68] [69] On January 19, 2018, PJM filed amended Schedule 12 Appendix and Appendix A revisions reflecting the Commissions orders eliminating the Linden and HTP cost responsibility assignments for RTEP projects with an effective date of January 1, 2018.[70]

Linden requested, and obtained, PJM long-term firm transmission through the long-term firm queue. PJM's Initial Study Long-Term Firm Transmission Service notes:

> ... For the purpose of this study, and as requested by the Customer, PJM assumed FERC approval to amend the pre-existing Linden VFT

66 155 FERC ¶ 61,089 (2016), *reh'g pending*. With rehearing pending, in light of subsequent developments, including service cancellations intended to avoid RTEP cost allocations, the Commission established settlement proceedings to consider settlement of this proceeding and related cost allocation proceedings. 164 FERC ¶ 61,034 (2018).
67 See *PJM Interconnection, L.L.C*, Docket No. ER17-2267-000 (August 9, 2017).
68 161 FERC ¶ 62,242 (2017).
69 161 FERC ¶ 62,264 (2017).
70 See *PJM Interconnection, L.L.C.*, Docket No. ER18-680-000 (January 19, 2018).

> Interconnection Service Agreements (Queue # U2-077 and W1-001) and resulting termination of the associated firm rights.

Linden requested that PJM provide an initial study with the assumption that FERC approves the termination of their FTWRs. Linden VFT expects to maintain the ability to export capacity to NYISO from PJM with the same level of transmission service they currently have under the FTWR construct while avoiding an RTEP cost allocation. Linden VFT has obtained assurance from NYISO that NFTWRs in conjunction with firm point to point transmission service from PJM to the Linden VFT point of delivery, will allow Linden VFT to continue to export capacity from PJM to NYISO exactly as they did with FTWRs.[71]

HTP has, to date, only requested conversion of its FTWRs to NFTWRs. Neptune was not allocated any RTEP costs and has not requested a change in service.

The claim that Linden and/or HTP could use NFTWRs in conjunction with firm point to point transmission to continue to export capacity from PJM to NYISO while avoiding RTEP costs is not correct.

Section 232.2 of the OATT states (emphasis added):

> … A Transmission Interconnection Customer that is granted Firm Transmission Withdrawal Rights and/or transmission customers that have a Point of Delivery at the Border of PJM where the Transmission System interconnects with the Merchant D.C. Transmission Facilities may be responsible for a reasonable allocation of transmission upgrade costs added to the Regional Transmission Expansion Plan after such Transmission Interconnection Customer's Queue Position is established, in accordance with Section 3E and Schedule 12 of the Tariff…

Section 232.2 of the OATT explicitly requires the same RTEP cost allocation when a transmission customer has FTWRs and when a transmission customer has "a Point of Delivery at the Border of PJM where the Transmission System interconnects with the Merchant D.C. Transmission Facilities." That is the situation here. Linden is structured as a controllable AC line which is functionally the same as a DC tie line. Identical treatment of RTEP costs is appropriate because the service is the same. Linden, if it relinquishes its FTWRs and instead uses firm point to point transmission service from PJM to the Linden VFT point of delivery and NFTWRs across the Linden VFT Line, would have the same service before and after the change. These two methods would be appropriately treated the same under Section 232.2, and HTP, if it follows Linden VFT's approach also would be treated the same.

With the conversion of HTP's and Linden's FTWRs to NFTWRs, any acquisition of long-term firm point to point transmission service from PJM to the point of interconnection with their DC tie line, HTP and/or Linden should continue to be assigned a portion of the RTEP cost responsibilities. But such assignment requires modification to Schedule 12 of the OATT to include the options defined in Section 232.2.[72] Once Schedule 12 is modified, HTP and/or Linden would become eligible to export capacity from PJM to the NYISO over their DC tie lines. Section 232.2 of the PJM Tariff combined with the NYISO deliverability requirements for capacity imports makes this explicit.

It would not be reasonable or consistent with economic logic to permit HTP and/or Linden to retain the same capacity export service with a different name and avoid an allocation of RTEP costs.

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.

The number of PJM issued TLRs of level 3a or higher increased from one in the first three months of 2018 to two in the first three months of 2019.[73] The number of different flowgates for which PJM declared a TLR 3a or higher

71 See *Discussion of UDR Deliverability Requirements* (September 18, 2017) at: <https://www.nyiso.com/documents/20142/1406254/UDR%20Deliverability%20Requirements.pdf/09988c85-84d5-f911-42ba-8c578695128d>.

72 PJM files cost responsibility assignments for transmission projects that are selected in the PJM Regional Transmission Expansion Plan (RTEP) for purposes of cost allocations in accordance with Schedule 12 of the OATT.

73 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2018 State of the Market Report for PJM*, Volume 2, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

was one in the first three months of 2018 and one in the first three months of 2019. The total MWh of transactions curtailed decreased by 54.3 percent from 3,283 MWh in the first three months of 2018 to 1,499 MWh in the first three months of 2019.

The number of MISO issued TLRs of level 3a or higher decreased from nine in the first three months of 2018 to eight in the first three months of 2019. The number of different flowgates for which MISO declared a TLR 3a increased from six in the first three months of 2018 to eight in the first three months of 2019. The total MWh of transaction curtailments decreased by 67.7 percent from 10,383 MWh in the first three months of 2018 to 3,358 MWh in the first three months of 2019.

The number of NYISO issued TLRs of level 3a or higher increased from one in the first three months of 2018 to five in the first three months of 2019. The number of different flowgates for which NYISO declared a TLR 3a or higher was one in the first three months of 2018 and one in the first three months of 2019. The total MWh of transaction curtailments increased by 932 percent from 1,428 MWh in the first three months of 2018 to 14,742 MWh in the first three months of 2019.

Table 9-39 PJM, MISO, and NYISO TLR procedures: January 2016 through March 2019

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-16	6	0	0	1	0	0	83,752	0	0
Feb-16	2	0	0	1	0	0	23,096	0	0
Mar-16	0	5	0	0	3	0	0	6,556	0
Apr-16	0	6	0	0	2	0	0	2,034	0
May-16	0	6	0	0	4	0	0	5,360	0
Jun-16	0	5	1	0	2	1	0	18,121	217
Jul-16	0	18	0	0	8	0	0	38,815	0
Aug-16	0	16	0	0	3	0	0	30,181	0
Sep-16	0	8	0	0	4	0	0	19,394	0
Oct-16	0	3	0	0	2	0	0	1,702	0
Nov-16	0	9	0	0	3	0	0	5,622	0
Dec-16	1	1	0	1	1	0	443	0	0
Jan-17	3	1	0	1	1	0	6,140	255	0
Feb-17	0	8	0	0	2	0	0	10,566	0
Mar-17	0	9	0	0	4	0	0	7,954	0
Apr-17	0	10	0	0	7	0	0	16,422	0
May-17	0	11	0	0	8	0	0	7,292	0
Jun-17	0	13	0	0	6	0	0	8,576	0
Jul-17	0	0	1	0	0	1	0	0	0
Aug-17	0	3	0	0	2	0	0	2,449	0
Sep-17	0	4	0	0	3	0	0	6,439	0
Oct-17	1	12	0	1	7	0	763	9,089	0
Nov-17	0	2	0	0	2	0	0	806	0
Dec-17	2	2	0	2	2	0	6,156	2,221	0
Jan-18	1	7	1	1	4	1	3,283	9,198	1,428
Feb-18	0	0	0	0	0	0	0	0	0
Mar-18	0	2	0	0	2	0	0	1,185	0
Apr-18	2	3	0	1	3	0	656	1,180	0
May-18	1	11	0	1	7	0	1,893	3,373	0
Jun-18	0	12	0	0	5	0	0	9,643	0
Jul-18	0	1	0	0	1	0	0	134	0
Aug-18	0	6	0	0	3	0	0	7,852	0
Sep-18	0	5	1	0	3	1	0	3,203	4,766
Oct-18	0	5	0	0	4	0	0	6,474	0
Nov-18	0	1	0	0	1	0	0	440	0
Dec-18	1	3	0	1	3	0	234	13,258	0
Jan-19	2	0	5	1	0	1	1,499	0	14,742
Feb-19	0	2	0	0	2	0	0	927	0
Mar-19	0	6	0	0	6	0	0	2,431	0

Table 9-40 Number of TLRs by TLR level by reliability coordinator: January through March, 2019[74]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2019	MISO	3	1	0	1	3	0	8
	NYIS	5	0	0	0	0	0	5
	ONT	3	0	0	0	0	0	3
	PJM	1	1	0	0	0	0	2
	SOCO	0	0	0	0	0	0	0
	SWPP	5	0	0	3	0	0	8
	TVA	2	7	0	2	3	0	14
	VACS	0	0	0	0	0	0	0
Total		19	9	0	6	6	0	40

Up To Congestion

The original purpose of up to congestion transactions (UTC) 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.[75]

Following the elimination of the requirement to procure and pay for transmission service for up to congestion transactions effective September 17, 2010, the volume of transactions increased dramatically.

Up to congestion transactions affect the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions do not pay operating reserves charges. Up to congestion transactions also negatively affect FTR funding.[76]

On August 29, 2014, FERC issued an order which created an obligation for UTCs to pay any uplift determined to be appropriate based on Commission review, effective September 8, 2014.[77]

As a result of the potential requirement to pay uplift charges and the uncertainty about the level of the required uplift charges, market participants reduced up to congestion trading effective September 8, 2014. There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges (Figure 9-13). Section 206(b) of the Federal Power Act states that "…the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date…"[78]

On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[79] As a result, market participants reduced up to congestion trading effective February 22, 2018.

The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 49.3 percent, from 105,194 bids per day in the first three months of 2018 to 53,376 bids per day in the first three months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market decreased by less than one percent, from 521,751 MWh per day in the first three months of 2018, to 521,709 MWh per day in the first three months of 2019.

74 Southern Company Services, Inc. (SOCO) is the reliability coordinator covering a portion of Mississippi, Alabama, Florida and Georgia. Southwest Power Pool (SWPP) is the reliability coordinator for SPP. VACAR-South (VACS) is the reliability coordinator covering a portion of North Carolina and South Carolina.
75 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.
76 See the *2019 Quarterly State of the Market Report for PJM: January through March*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.
77 148 FERC ¶ 61,144 (2014).
78 16 U.S.C. § 824e.
79 162 FERC ¶ 61,139 (2018).

Figure 9-13 Monthly up to congestion cleared bids in MWh: January 2005 through March 2019

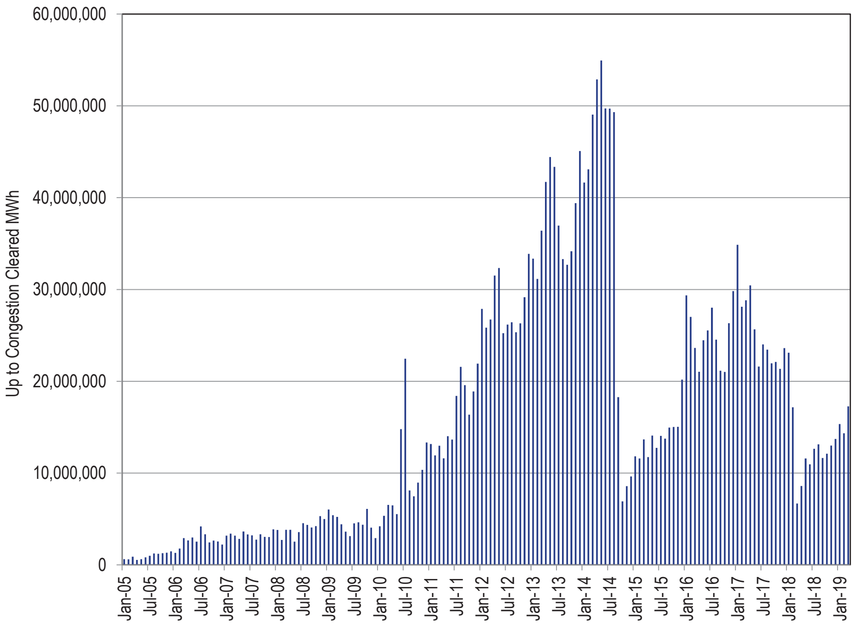


Table 9-41 Monthly volume of cleared and submitted up to congestion bids: January 2018 through March 2019

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-18	6,693,483	7,662,968	964,569	77,009,951	92,330,971	248,760	203,232	17,467	4,374,531	4,843,990
Feb-18	5,221,484	6,409,422	819,944	51,178,869	63,629,719	178,507	175,403	18,605	2,787,881	3,160,396
Mar-18	7,198,570	2,684,392	1,641,523	9,285,316	20,809,801	405,718	170,727	76,172	810,443	1,463,060
Apr-18	10,593,924	3,145,340	2,567,203	15,365,820	31,672,285	479,450	120,650	68,477	771,799	1,440,376
May-18	11,309,503	3,914,473	2,621,845	19,453,217	37,299,037	517,327	119,707	53,586	886,577	1,577,197
Jun-18	10,165,362	3,767,069	2,613,562	16,723,385	33,269,378	399,986	87,810	40,434	763,388	1,291,618
Jul-18	9,895,083	2,011,081	2,397,682	22,207,892	36,511,737	488,146	129,135	48,678	1,183,510	1,849,469
Aug-18	13,524,492	1,838,512	3,071,033	21,055,373	39,489,410	561,803	100,964	46,574	1,014,352	1,723,693
Sep-18	10,503,480	4,148,333	3,322,123	20,309,280	38,283,216	445,037	94,821	51,019	812,439	1,403,316
Oct-18	10,977,336	4,063,127	2,832,812	19,223,993	37,097,269	435,432	133,048	50,325	954,489	1,573,294
Nov-18	11,903,568	4,093,631	2,752,372	23,118,009	41,867,580	474,565	96,770	44,125	950,934	1,566,394
Dec-18	8,557,434	3,709,128	2,408,350	26,836,764	41,511,676	276,497	103,963	47,479	1,248,751	1,676,690
Jan-19	9,353,494	3,989,206	2,204,341	33,209,495	48,756,536	317,900	137,306	61,239	1,335,488	1,851,933
Feb-19	7,584,708	5,424,852	1,991,198	29,512,609	44,513,366	242,071	142,957	50,914	916,766	1,352,708
Mar-19	11,841,555	4,801,188	3,292,862	36,636,988	56,572,593	320,490	105,336	58,064	1,115,308	1,599,198
TOTAL	145,323,475	61,662,720	35,501,418	421,126,962	663,614,574	5,791,689	1,921,829	733,158	19,926,656	28,373,332

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-18	1,467,644	1,595,640	259,173	19,790,703	23,113,162	72,327	67,941	6,648	1,470,535	1,617,451
Feb-18	1,312,958	1,559,790	223,702	14,068,590	17,165,039	65,952	70,121	8,429	1,103,722	1,248,224
Mar-18	2,228,586	819,477	399,161	3,232,145	6,679,368	145,743	55,930	24,612	318,655	544,940
Apr-18	2,951,060	728,157	352,423	4,557,862	8,589,502	191,558	40,919	19,629	379,069	631,175
May-18	3,891,624	1,073,540	638,477	5,996,981	11,600,622	215,222	48,034	21,288	381,157	665,701
Jun-18	3,473,835	1,218,987	769,637	5,500,944	10,963,403	172,868	43,078	17,529	361,764	595,239
Jul-18	3,756,816	616,857	691,554	7,588,929	12,654,157	234,818	51,413	21,034	512,342	819,607
Aug-18	4,449,172	759,823	929,122	6,999,351	13,137,468	248,048	43,884	20,619	429,365	741,916
Sep-18	3,382,522	1,130,568	813,755	6,322,535	11,649,379	189,297	37,680	17,342	372,208	616,527
Oct-18	3,372,457	1,254,074	665,212	6,823,263	12,115,006	182,064	56,691	18,422	441,069	698,246
Nov-18	3,614,335	1,206,420	657,895	7,518,666	12,997,315	210,762	54,479	21,050	460,142	746,433
Dec-18	2,988,179	1,139,101	674,573	8,921,740	13,723,593	126,333	60,064	20,146	650,430	856,973
Jan-19	3,646,671	1,270,480	719,143	9,708,127	15,344,421	163,962	69,096	25,497	648,338	906,893
Feb-19	2,891,175	1,759,853	660,811	9,029,295	14,341,133	113,778	70,552	21,952	469,157	675,439
Mar-19	4,473,700	1,543,428	1,126,598	10,124,498	17,268,224	153,456	50,367	23,840	550,873	778,536
TOTAL	47,900,733	17,676,194	9,581,237	126,183,629	201,341,793	2,486,188	820,249	288,037	8,548,826	12,143,300

In the first three months of 2019, the cleared MW volume of up to congestion transactions was comprised of 23.5 percent imports, 9.7 percent exports, 5.3 percent wheeling transactions and 61.5 percent internal transactions. Less than 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 cannot see how the power will flow to the load, which can create loop flows and result in 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 path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT path, and a second segment on the ONT-MISO-PJM path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source were Ontario (the ONT interface price).

Sham scheduling can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule.

For example, market participants can submit one transaction with multiple segments among balancing authorities and another transaction which offsets all or part of a segment of the first transaction. If a market participant submits two separate transactions, one on the ONT-MISO-PJM path, and a second on the PJM-MISO path, the result of these transactions would be a net scheduled transaction from ONT to MISO, as the MISO-PJM segment of the first transaction is offset by the PJM-MISO transaction. In this example, PJM is not required to raise or lower generation as a result of these transactions, as they would for an import or an export, and there are no associated power flows across PJM. Nonetheless, the market participant is paid the price difference between the PJM/ONT interface pricing point and the PJM/MISO interface pricing point. The market participant would be paid the PJM/ONT interface pricing point for the first transaction (ONT to PJM import) and the market participant would pay the PJM/MISO interface pricing point for the second transaction (PJM to MISO export). If the PJM/ONT interface price were higher than the PJM/MISO interface price, the market participant would be paid a net profit from the PJM market even though there was no impact on PJM operations.

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling.

Elimination of Ontario Interface Pricing Point

The PJM/IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the PJM/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.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The noncontiguous nature of the PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities. For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would use the PJM spot market as a temporary load and generation point to wheel transactions through the PJM energy market. This was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO Interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e. 100 percent weighting on the PJM/NYIS Interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00.[80]

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

In the first three months of 2019, of the 362 GWh of the gross scheduled transactions between PJM and IESO, 361 GWh (99.7 percent) wheeled through MISO (Table 9-24). The MMU recommends that PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[81]

PJM and NYISO Coordinated Interchange Transactions

Coordinated transaction scheduling (CTS) provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated.[82] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price ITSCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

80 See "IMO Interface Definition Methodology Report," presented to the MIC (February 11, 2015) <http://www.pjm.com/~/media/committees-groups/committees/mic/20150211/20150211-item-08b-imo-interface-definition-methodology-report.ashx>.

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

82 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

The ITSCED application runs approximately every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for the first three months of 2019. Table 9-42 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 41.8 percent of the intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.46 per MWh. In 9.2 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $81.46 when the price difference was greater than $20.00, and $304.91 when the price difference was greater than -$20.00.

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: January through March, 2019

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	3.6%	$81.46
$10 to $20	2.8%	$13.84
$5 to $10	4.8%	$7.00
$0 to $5	41.8%	$1.46
$0 to -$5	35.0%	$1.39
-$5 to -$10	3.8%	$6.95
-$10 to -$20	2.5%	$14.42
< -$20	5.6%	$304.91

Table 9-43 shows how the accuracy of the ITSCED forecasted LMPs changes as the cases approach real-time. In the final ITSCED results prior to real time, in 78.3 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 76.0 percent in the 135 minute ahead ITSCED results.

Table 9-43 Differences between forecast and actual PJM/NYIS interface prices: January through March, 2019

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	2.3%	$74.92	2.7%	$72.54	2.9%	$75.25	3.3%	$77.44
$10 to $20	2.0%	$13.56	2.5%	$13.44	2.3%	$14.32	2.5%	$13.79
$5 to $10	3.6%	$7.11	4.1%	$7.15	4.1%	$6.97	4.9%	$6.98
$0 to $5	28.9%	$1.49	30.4%	$1.49	41.6%	$1.43	42.9%	$1.47
$0 to -$5	47.1%	$1.59	46.5%	$1.54	35.7%	$1.42	35.4%	$1.39
-$5 to -$10	5.4%	$7.00	5.2%	$6.87	4.2%	$6.96	3.8%	$7.01
-$10 to -$20	3.5%	$14.66	3.2%	$14.58	2.8%	$14.21	2.3%	$14.48
< -$20	7.0%	$340.69	5.5%	$201.01	6.3%	$374.34	4.8%	$215.42

In 8.1 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price difference was $77.44 when the price difference was greater than $20.00, and $215.42 when the price difference was greater than -$20.00.

Table 9-44 and Table 9-45 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the ITSCED forecast ability during periods of cold and hot weather.

Table 9-44 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): January through March, 2019

Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	5.7%	2.7%	1.4%	3.3%
	$10 to $20	2.7%	2.1%	2.8%	2.5%
	$5 to $10	4.5%	3.6%	6.5%	4.9%
	$0 to $5	37.7%	45.1%	46.1%	42.9%
	$0 to -$5	35.7%	36.9%	33.8%	35.4%
	-$5 to -$10	4.4%	3.2%	3.8%	3.8%
	-$10 to -$20	3.0%	2.2%	1.8%	2.3%
	< -$20	6.4%	4.2%	3.8%	4.8%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	5.1%	2.4%	1.0%	2.9%
	$10 to $20	3.3%	1.6%	2.1%	2.3%
	$5 to $10	3.4%	3.5%	5.4%	4.1%
	$0 to $5	37.5%	44.1%	43.5%	41.6%
	$0 to -$5	36.3%	37.0%	34.1%	35.7%
	-$5 to -$10	4.4%	3.3%	5.0%	4.2%
	-$10 to -$20	3.5%	2.9%	2.1%	2.8%
	< -$20	6.6%	5.2%	6.9%	6.3%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	4.6%	1.3%	2.0%	2.7%
	$10 to $20	2.9%	1.5%	3.2%	2.5%
	$5 to $10	3.9%	2.3%	5.9%	4.1%
	$0 to $5	25.8%	29.3%	35.9%	30.4%
	$0 to -$5	44.6%	53.2%	42.4%	46.5%
	-$5 to -$10	6.3%	4.2%	4.9%	5.2%
	-$10 to -$20	4.5%	3.3%	1.9%	3.2%
	< -$20	7.5%	4.9%	3.9%	5.5%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	4.4%	1.0%	1.4%	2.3%
	$10 to $20	2.8%	1.2%	2.0%	2.0%
	$5 to $10	3.7%	2.3%	4.8%	3.6%
	$0 to $5	24.6%	27.5%	34.6%	28.9%
	$0 to -$5	45.8%	54.0%	42.3%	47.1%
	-$5 to -$10	6.2%	4.1%	5.8%	5.4%
	-$10 to -$20	4.7%	3.6%	2.2%	3.5%
	< -$20	7.8%	6.3%	6.9%	7.0%

Table 9-45 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January through March, 2019

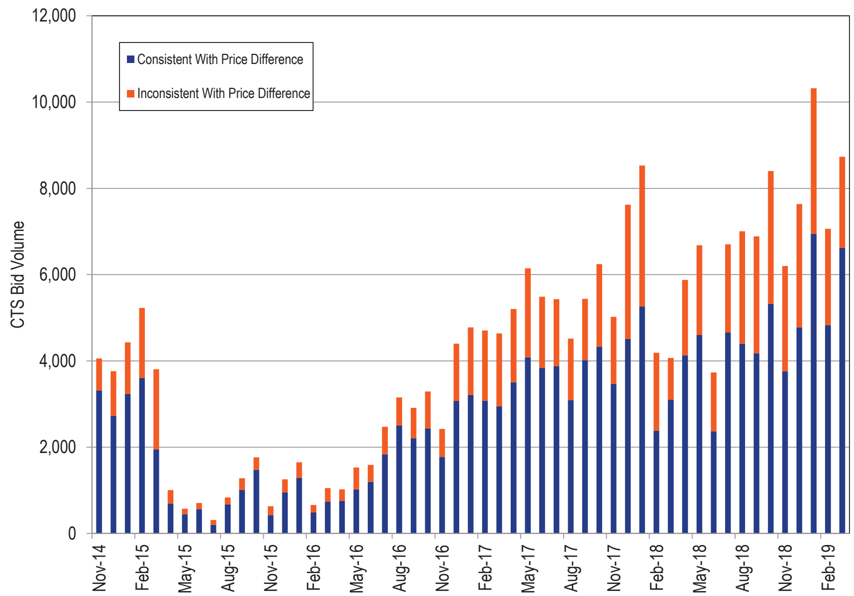
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$79.73	$90.51	$45.45	$77.44
	$10 to $20	$13.95	$13.81	$13.64	$13.79
	$5 to $10	$7.12	$6.73	$7.02	$6.98
	$0 to $5	$1.44	$1.41	$1.54	$1.47
	$0 to -$5	$1.40	$1.32	$1.45	$1.39
	-$5 to -$10	$6.93	$7.15	$6.99	$7.01
	-$10 to -$20	$14.75	$14.47	$14.03	$14.48
	< -$20	$109.20	$169.71	$436.84	$215.42
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$78.44	$85.72	$37.73	$75.25
	$10 to $20	$14.51	$15.06	$13.50	$14.32
	$5 to $10	$7.16	$6.86	$6.91	$6.97
	$0 to $5	$1.43	$1.38	$1.47	$1.43
	$0 to -$5	$1.41	$1.37	$1.47	$1.42
	-$5 to -$10	$6.93	$6.99	$6.96	$6.96
	-$10 to -$20	$14.46	$13.97	$14.09	$14.21
	< -$20	$104.35	$272.98	$701.93	$374.34
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$86.98	$63.07	$44.96	$72.54
	$10 to $20	$13.73	$12.83	$13.44	$13.44
	$5 to $10	$7.15	$7.24	$7.13	$7.15
	$0 to $5	$1.52	$1.43	$1.52	$1.49
	$0 to -$5	$1.54	$1.53	$1.55	$1.54
	-$5 to -$10	$6.82	$6.84	$6.97	$6.87
	-$10 to -$20	$15.06	$14.30	$13.86	$14.58
	< -$20	$102.51	$154.46	$440.43	$201.01
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$87.42	$64.44	$43.97	$74.92
	$10 to $20	$13.68	$12.62	$13.88	$13.56
	$5 to $10	$7.24	$7.05	$7.03	$7.11
	$0 to $5	$1.43	$1.41	$1.59	$1.49
	$0 to -$5	$1.61	$1.58	$1.59	$1.59
	-$5 to -$10	$6.89	$6.99	$7.12	$7.00
	-$10 to -$20	$15.07	$14.32	$14.31	$14.66
	< -$20	$99.93	$241.48	$695.65	$340.69

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

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The NYISO has a 75 minute bid submission deadline. While market participants have the option to specify bid data on 15 minute intervals, market participants must submit their bids 75 minutes prior to the requested transaction start time. The 75 minute bid submission deadline associated with scheduling energy transactions in the NYISO should be shortened. Reducing this deadline could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions as market participants would be able to adjust their bids in response to real-time price signals.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through March 31, 2019, 223,020 15 minute CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 71,146 (31.9 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 31.9 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 68.1 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-14 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-14 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-14 Monthly cleared PJM/NYIS CTS bid volume: November 4, 2014 through March 31, 2019



The data reviewed show that ITSCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. If this remains true, it will limit the effectiveness of CTS in improving interface pricing between PJM and NYISO.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within +/- 1,000. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation is based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process uses a joint clearing process in which both RTOs share forward looking prices. On October 3, 2017, PJM and MISO implemented the CTS process.

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for the first three months of 2019. Table 9-46 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 43.7 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.50. In 6.4 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $62.15 when the price difference was greater than $20.00, and $373.74 when the price difference was greater than -$20.00.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: January through March, 2019

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	2.5%	$62.15
$10 to $20	2.7%	$13.92
$5 to $10	5.3%	$6.96
$0 to $5	43.7%	$1.50
$0 to -$5	36.5%	$1.37
-$5 to -$10	3.4%	$6.93
-$10 to -$20	2.1%	$14.34
< -$20	3.9%	$373.74

Table 9-47 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time. In the final ITSCED results prior to real-time, in 81.9 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 80.9 percent in the 135 minute ahead ITSCED results.

Table 9-47 Differences between forecast and actual PJM/MISO interface prices: January through March, 2019

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	1.3%	$46.42	1.3%	$44.74	1.7%	$47.03	1.7%	$45.11
$10 to $20	1.7%	$13.56	1.8%	$13.91	2.3%	$14.00	2.2%	$13.67
$5 to $10	3.7%	$7.07	3.7%	$6.96	5.2%	$6.95	5.4%	$7.02
$0 to $5	29.3%	$1.50	30.3%	$1.47	45.7%	$1.51	46.5%	$1.51
$0 to -$5	51.6%	$1.58	50.8%	$1.57	36.2%	$1.33	35.4%	$1.32
-$5 to -$10	5.1%	$6.82	4.9%	$6.89	3.2%	$6.96	3.1%	$7.02
-$10 to -$20	3.0%	$14.31	2.9%	$14.45	2.1%	$14.29	2.0%	$14.20
< -$20	4.4%	$405.90	4.2%	$291.46	3.7%	$387.02	3.6%	$339.02

In 5.3 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $45.11 when the price difference was greater than $20.00, and $339.02 when the price difference was greater than -$20.00.

Table 9-48 and Table 9-49 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the ITSCED forecast ability during periods of cold and hot weather.

Table 9-48 Monthly Differences between forecast and actual PJM/MISO interface prices (percent of intervals): January through March, 2019

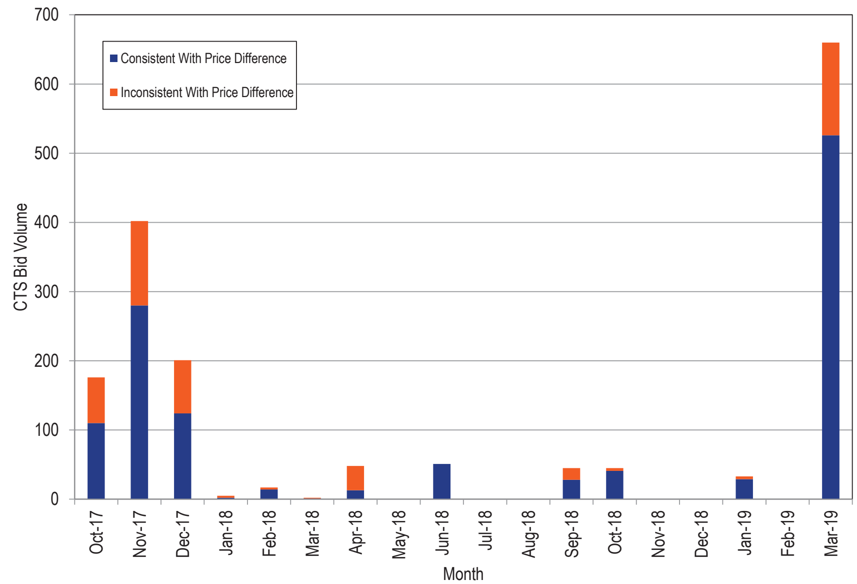
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	2.7%	1.6%	0.9%	1.7%
	$10 to $20	2.2%	2.3%	2.3%	2.2%
	$5 to $10	3.5%	5.6%	7.2%	5.4%
	$0 to $5	45.3%	45.9%	48.3%	46.5%
	$0 to -$5	39.8%	34.5%	31.9%	35.4%
	-$5 to -$10	3.1%	2.9%	3.3%	3.1%
	-$10 to -$20	1.8%	2.4%	1.8%	2.0%
	< -$20	1.8%	4.8%	4.4%	3.6%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	2.4%	1.7%	0.9%	1.7%
	$10 to $20	2.4%	2.4%	2.1%	2.3%
	$5 to $10	3.3%	5.5%	6.7%	5.2%
	$0 to $5	45.0%	44.8%	47.1%	45.7%
	$0 to -$5	40.2%	35.5%	32.9%	36.2%
	-$5 to -$10	3.4%	3.1%	3.1%	3.2%
	-$10 to -$20	1.6%	2.5%	2.3%	2.1%
	< -$20	1.8%	4.4%	4.9%	3.7%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	1.8%	0.6%	1.5%	1.3%
	$10 to $20	1.9%	1.7%	1.9%	1.8%
	$5 to $10	2.9%	3.1%	5.1%	3.7%
	$0 to $5	27.5%	26.6%	36.4%	30.3%
	$0 to -$5	55.1%	54.4%	43.3%	50.8%
	-$5 to -$10	5.2%	5.1%	4.4%	4.9%
	-$10 to -$20	3.2%	3.2%	2.3%	2.9%
	< -$20	2.4%	5.2%	5.0%	4.2%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	1.9%	0.7%	1.2%	1.3%
	$10 to $20	1.8%	1.4%	1.9%	1.7%
	$5 to $10	2.8%	2.9%	5.2%	3.7%
	$0 to $5	26.6%	25.6%	35.2%	29.3%
	$0 to -$5	55.8%	55.5%	43.7%	51.6%
	-$5 to -$10	5.0%	5.5%	4.9%	5.1%
	-$10 to -$20	3.4%	3.1%	2.5%	3.0%
	< -$20	2.6%	5.3%	5.4%	4.4%

Table 9-49 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January through March, 2019

Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$44.69	$44.07	$47.98	$45.11
	$10 to $20	$14.36	$13.27	$13.39	$13.67
	$5 to $10	$7.17	$6.92	$7.02	$7.02
	$0 to $5	$1.34	$1.55	$1.62	$1.51
	$0 to -$5	$1.21	$1.36	$1.42	$1.32
	-$5 to -$10	$7.24	$6.97	$6.85	$7.02
	-$10 to -$20	$14.22	$14.22	$14.16	$14.20
	< -$20	$77.60	$179.96	$604.25	$339.02
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$50.71	$43.83	$43.20	$47.03
	$10 to $20	$15.00	$13.44	$13.46	$14.00
	$5 to $10	$7.12	$6.95	$6.88	$6.95
	$0 to $5	$1.32	$1.56	$1.66	$1.51
	$0 to -$5	$1.23	$1.36	$1.42	$1.33
	-$5 to -$10	$7.08	$7.00	$6.79	$6.96
	-$10 to -$20	$14.69	$14.48	$13.83	$14.29
	< -$20	$64.73	$181.49	$677.95	$387.02
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$48.58	$42.18	$41.28	$44.74
	$10 to $20	$14.66	$13.20	$13.75	$13.91
	$5 to $10	$7.08	$6.79	$6.98	$6.96
	$0 to $5	$1.29	$1.48	$1.61	$1.47
	$0 to -$5	$1.47	$1.64	$1.60	$1.57
	-$5 to -$10	$7.06	$6.71	$6.87	$6.89
	-$10 to -$20	$15.20	$14.00	$13.97	$14.45
	< -$20	$73.77	$209.99	$476.22	$291.46
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$50.44	$43.01	$41.85	$46.42
	$10 to $20	$13.48	$12.92	$14.08	$13.56
	$5 to $10	$7.27	$7.11	$6.94	$7.07
	$0 to $5	$1.29	$1.59	$1.60	$1.50
	$0 to -$5	$1.51	$1.62	$1.64	$1.58
	-$5 to -$10	$7.06	$6.62	$6.79	$6.82
	-$10 to -$20	$14.89	$13.95	$13.92	$14.31
	< -$20	$61.97	$236.83	$723.62	$405.90

CTS transactions were evaluated for each interval. From October 3, 2017, through March 31, 2019, 1,685 CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 466 (27.7 percent) of the intervals was inconsistent with the differences in real-time PJM/MISO and MISO/PJM prices. For example, if a market participant submits a CTS transaction from MISO to PJM with a spread bid of $5.00, and MISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted MISO interface price, the transaction would be approved. For 27.7 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 72.3 percent of the intervals, the forecast price differentials were consistent with real-time PJM/MISO and MISO/PJM price differences. Figure 9-15 shows the monthly volume of cleared PJM/MISO CTS bids. Figure 9-15 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-15 Monthly cleared PJM/MISO CTS bid volume: October 3, 2017 through March 31, 2019



The data reviewed show that ITSCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. If this remains true, it will limit the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm 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 participant pays in order for their transaction to continue to flow.

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

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU 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 appropriate to address this exposure.

Table 9-50 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only two months (January 2016 and February 2019). In both months, there was negative uncollected congestion. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in both January 2016 and February 2019.

Table 9-50 Monthly uncollected congestion charges: January 2010 through March 2019

Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0	$0	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0	$0	($69,992)
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	$0	$0	
May	$41,025	$0	($27)	$0	$0	$0	$0	$0	$0	
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	$0	$0	
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	$0	$0	
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0	
Sep	$119,162	$0	$0	$0	$0	$0	$0	$0	$0	
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	$0	$0	
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	$0	$0	
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	$0	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0	$0	($69,992)

Spot Imports

Prior to April 1, 2007, PJM did not limit nonfirm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using nonfirm point-to-point service. Spot market imports, nonfirm point-to-point and network services that are willing to pay congestion, all termed 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.

However, PJM has interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[83] The result is that the availability of spot import service is limited by ATC and not all spot transactions are approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

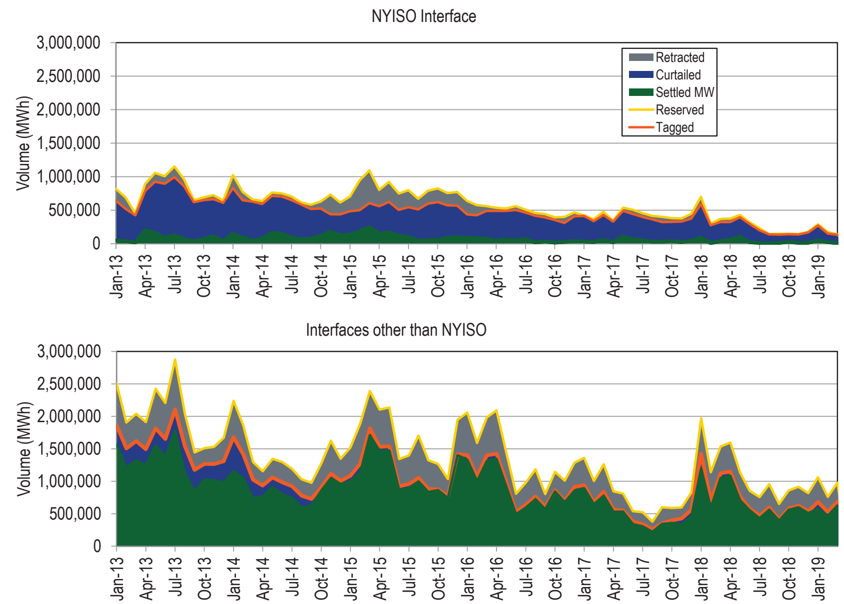
83 See OASIS "Modifications to the Practices of Non-Firm and Spot Market Import Service" (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>.

The spot import rules provide incentives to hoard spot import capability. In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[84] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within two hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

These changes did not fully resolve the issue. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the queue time of the reservations intraday, and two hours when queued the day prior. On June 23, 2009, PJM implemented the new business rules.

Figure 9-16 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through March 31, 2019. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded area between the yellow and orange lines represents the MWh of retracted spot import service and may represent potential hoarding volumes. This ATC was initially reserved, but not tagged (used). It is possible that in some instances the reserved transmission consisted of the only available ATC which could have been used by another market participant had it not been reserved and not used. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot import service. This area may also represent hoarding opportunities, particularly at the NYISO Interface. In this instance, it is possible that while the market participant reserved and scheduled the transmission, they may have submitted purposely uneconomic bids in the NYISO market so that their transaction would be curtailed, yet their transmission would not be retracted. The NYISO allows for market participants to modify their bids on an hourly basis, so these market participants can hold their transmission service and evaluate their bids hourly, while withholding the transmission from other market participants that may wish to use it. The green shaded area represents the total settled MWh of spot import service. Figure 9-16 shows that while there are proportionally fewer retracted MWh on the NYISO Interface than on all other interfaces, the NYISO has proportionally more curtailed MWh. This is a result of the NYISO market clearing process.

Figure 9-16 Spot import service use: January 2013 through March 2019



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

84 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 7 (December 19, 2018) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Interchange Optimization

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

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes.[85] These changes would give PJM a more flexible product that could be used to meet load based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments affect the duration of interchange transactions.

The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

85 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 764.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point-to-point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market-based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, were dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes. Therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real-time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

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

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

On June 22, 2012, FERC issued Order No. 764, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.[86] [87] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[88]

PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[89]

MISO Multi-Value Project Usage Rate (MUR)

A multi-value project (MVP) is a project, as defined by MISO, which enables the reliable and economic delivery of energy in support of public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value.[90] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[91] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[92] The Commission stated that MISO had not shown that their proposal did not constitute a resumption of rate pancaking along the MISO-PJM seam. Following the December 16, 2010, Order, MISO began applying a multi-value usage rate (MUR) to monthly net actual energy withdrawals, export schedules and through schedules with the exception of transactions sinking in PJM. The MUR charge was applied to the relevant transactions in addition to the applicable transmission, ancillary service and network upgrade charges.

On June 7, 2014, the U.S. Court of Appeals for the Seventh Circuit granted a petition for review regarding the Commission's determination in the MVP

86 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
87 Order No. 764 at P 51.
88 *See Id.* at P 12.
89 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014 <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.
90 See MISO. MTEP "Multi Value Project Portfolio Analysis," <https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf>.
91 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
92 133 FERC ¶ 61,221 (2010); order on reh'g, 137 FERC ¶ 61,074 (2011).

Order and MVP Rehearing Order.[93] The Court ordered the Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[94] The Seventh Circuit highlighted the fact that at the time of the Commission's decision to prohibit rate pancaking on transactions between MISO and PJM, all of MISO's transmission projects were local and provided only local benefits.[95]

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[96] The July 13th Order noted that in light of "the development of large scale wind generation capable of serving both MISO's and its neighbors' energy policy requirements in the western areas of MISO; the reported need of PJM entities to access those resources; and the reported need for MISO to build new transmission facilities to deliver the output of those resources within MISO for export... it is appropriate to allow MISO to assess the MVP usage charge for transmission service used to export to PJM just as MISO assesses the MVP usage charge for transmission service used to export energy to other regions."[97]

Table 9-51 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2019 through 2038.[98] It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-51 MISO projected multi value project usage rate: 2019 through 2038

Year	Total Indicative MVP Usage Rate ($/MWh)
2019	$1.76
2020	$1.77
2021	$1.76
2022	$1.76
2023	$1.76
2024	$1.83
2025	$1.77
2026	$1.75
2027	$1.74
2028	$1.72
2029	$1.70
2030	$1.68
2031	$1.66
2032	$1.65
2033	$1.63
2034	$1.61
2035	$1.60
2036	$1.58
2037	$1.56
2038	$1.55

93 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
94 *Id.* at 780.
95 *Id.* at 779.
96 156 FERC ¶ 61,034 (2016).
97 *Id.* at P 55.
98 See MISO, "Schedule 26A Indicative Annual Charges" (August 29, 2016) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.