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 nine months of 2025, PJM was a monthly net exporter of energy in the real-time energy market in all months.[1] In the first nine months of 2025, the real-time net interchange was -29,800.7 GWh. The real-time net interchange in the first nine months of 2024 was -27,542.0 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2025, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In the first nine months of 2025, the total day-ahead net interchange was -26,230.6 GWh. The day-ahead net interchange in the first nine months of 2024 was -24,393.4 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2025, gross imports in the day-ahead energy market were 62.0 percent of gross imports in the real-time energy market (75.3 percent in the first nine months of 2024). In the first nine months of 2025, gross exports in the day-ahead energy market were 80.4 percent of the gross exports in the real-time energy market (84.8 percent in the first nine months of 2024).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2025, there were net scheduled exports at 14 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 nine months of 2025, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions in the real-time energy market.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2025, there were net scheduled exports at 15 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 nine months of 2025, there were net scheduled exports at six of PJM's seven 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 nine months of 2025, up to congestion transactions were net exports at three of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Inadvertent Interchange.** In the first nine months of 2025, net scheduled interchange was -29,800.7 GWh and net actual interchange was -29,592.4 GWh, a difference of 208.4 GWh. In the first nine months of 2024, the difference was 196.4 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first nine months of 2025, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -799.7 GWh of net scheduled interchange and -8,409.3 GWh of net actual interchange, a difference of 7,609.6 GWh. In the first nine months of 2025, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 2,746.0 GWh of net scheduled interchange and 6,535.3 GWh of net actual interchange, a difference of 3,789.3 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2025, 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 52.4 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.

- **PJM and New York ISO Interface Prices.** In the first nine months of 2025, 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 59.2 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2025, 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 81.5 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2025, 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 80.3 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2025, 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 80.7 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 nine months of 2025, and zero such TLRs in the first nine months of 2024.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 57.7 percent, from 36,083 bids per day in the first nine months of 2024 to 48,979 bids per day in the first nine months of 2025. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 10.1 percent, from 237,417 MWh per day in the first nine months of 2024, to 264,091 MWh per day in the first nine months of 2025.

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.)
- 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 transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported 2020. 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 authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU 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 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.)
- The MMU recommends eliminating the mechanism that defines FFE and M2M payments. These mechanisms are not consistent with markets and are not needed for efficient interface pricing. The MMU recommends that PJM file with the Commission to eliminate the FFE calculation and M2M payment of the PJM and MISO joint operating agreement. (Priority: Medium. First reported 2024. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends clear rules governing when PJM may recall capacity backed exports. (Priority: Medium. First reported 2010. Status: Partially adopted.)

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 of an energy market including 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.

It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. External entities wishing to receive the benefits of the PJM LMP market should join PJM.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. Following the termination of the Northwest pricing point on October 1, 2020, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. The MMU continues to recommend the termination of the Ontario interface pricing point. The Ontario interface pricing point is noncontiguous to the PJM footprint that creates opportunities for market participants to engage in sham scheduling activities.

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.[2]

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		X
Balancing Operating Reserve	X	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

2 For an explanation and current rate for each billing line item, see "*Quick Reference Guide to Market Settlements By Type of Business*" (February 1, 2023) <https://www.pjm.com/-/media/DotCom/training/core-curriculum/ip-ms-301/ms-301-quick-reference-guide-to-markets-settlements-by-type-of-business.pdf>.

Aggregate Imports and Exports

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for the first nine months of 2024 and 2025. In the first nine months of 2025, gross imports in the day-ahead energy market were 62.0 percent of gross imports in the real-time energy market (75.3 percent in the first nine months of 2024). In the first nine months of 2025, gross exports in the day-ahead energy market were 80.4 percent of gross exports in the real-time energy market (84.8 percent in the first nine months of 2024).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): January through September, 2024 and 2025

Category	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change
Real-Time Gross Imports	10,781.6	12,328.6	14.3%
Real-Time Gross Exports	38,323.6	42,129.3	9.9%
Real-Time Net Interchange	(27,542.0)	(29,800.7)	8.2%
Day-Ahead Gross Imports	8,115.1	7,646.1	(5.8%)
Day-Ahead Gross Exports	32,508.5	33,876.7	4.2%
Day-Ahead Net Interchange	(24,393.4)	(26,230.6)	7.5%
Monthly Average Real-Time Gross Exports	4,258.2	4,681.0	9.9%
Monthly Average Real-Time Gross Imports	1,198.0	1,369.8	14.3%
Monthly Average Day-Ahead Gross Exports	3,612.1	3,764.1	4.2%
Monthly Average Day-Ahead Gross Imports	901.7	849.6	(5.8%)

In the first nine months of 2025, PJM was a monthly net exporter of energy in the real-time energy market in all months. In the first nine months of 2025, PJM was a monthly net exporter of energy in the day-ahead energy market in all months (Figure 9-1).[3]

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. Up to congestion transactions also create financial obligations to deliver in real time, but did not pay operating reserve charges until November 1, 2020.

Figure 9-1 Scheduled imports and exports: January through September, 2025

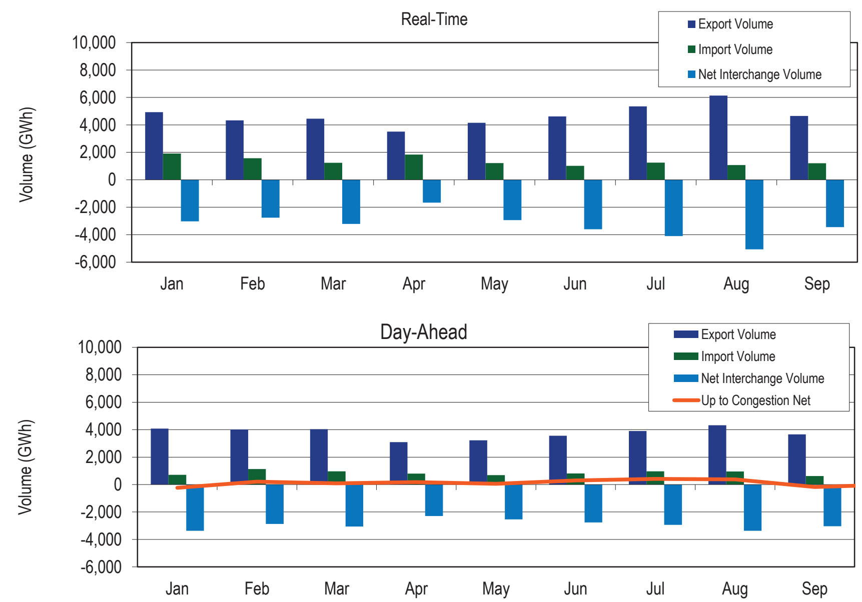


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through September 2025. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the real-time and day-ahead energy markets, coincident with the 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 expected to be 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

3 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.

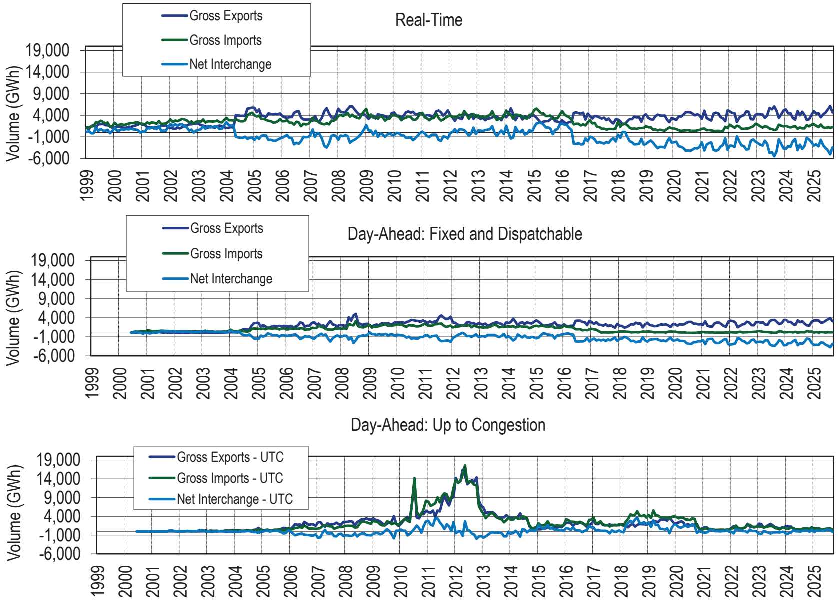
November 1, 2012, PJM eliminated the requirement that every up to congestion transaction include an interface pricing point as either the source or sink. As a result, the volume of import and export up to congestion transactions decreased, and the volume of internal up to congestion transactions increased. 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. 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.[4] As a result, the volume of import and export up to congestion transactions increased, contributing to PJM becoming a net importer in the day-ahead energy market starting in March 2018. On July 16, 2020, FERC issued an order directing PJM to revise uplift allocation rules to allocate uplift to up to congestion transactions.[5] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. As a result, the volume of up to congestion transactions decreased, and PJM became a net exporter in the day-ahead energy market.

In February 2021, winter storms caused significant generation outages in Texas and resulted in power outages across the Electric Reliability Council of Texas (ERCOT) region. These outages occurred between February 10, 2021, and February 27, 2021. During this time, ERCOT imported generation from neighboring regions. While PJM did not have any scheduled exports directly to the ERCOT region, PJM exports during this time increased from an average hourly export of 4,772 MW per hour between February 1 and February 10, 2021, to 7,003 MW per hour between February 10 and February 27, 2021.

On June 13, 2022, PJM experienced several intervals of shortage pricing that resulted in high LMPs during the period from 1450 (EPT) through 1800 (EPT). PJM remained a net exporter of energy throughout the period despite the fact that PJM prices were much higher than MISO prices. PJM net exports averaged 4,431 MW during hours ending 1500 (EPT) through 1800 (EPT), a slight decrease from average net exports of 5,560 MW during the hours ending 1100 (EPT) through 1400 (EPT). Market participant response to the pricing signals in this period was affected by TLRs issued by MISO, SWPP and PJM, although the curtailments of scheduled imports to PJM were relatively small compared to the net exports. Export transactions to MISO continued to flow during this period primarily on firm and grandfathered transmission service. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first nine months of 2025, flows were in the uneconomic direction on the PJM/MISO interface in 47.6 percent of all hours.

4 162 FERC ¶ 61,139.
5 172 FERC ¶ 61,046.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through September 30, 2025



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 9-19 includes a list of active interfaces in the first nine months of 2025. Figure 9-3 shows the approximate geographic location of the interfaces. In the first nine months of 2025, 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. 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 nine months of 2025 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 nine months of 2025, there were net scheduled exports at 14 of PJM's 19 interfaces. The top three net exporting interfaces in the real-time energy market accounted for 55.4 percent of the total net scheduled exports: PJM/NYISO (NYIS) with 21.1 percent, PJM/Cinergy (CIN) with 20.2 percent and PJM/MidAmerican Energy Company (MEC) with 14.2 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 48.1 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 49.3 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first nine months of 2025, there were net scheduled imports at four of PJM's 19 interfaces. The top two importing interfaces in the real-time energy market accounted for 75.6 percent of the total net scheduled imports: PJM/Duke (DUK) with 42.3 percent and PJM/Ameren-Illinois (AMIL) with 33.4 percent of the total 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 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 (Ameren-Illinois (AMIL) and Indianapolis Power & Light (IPL). These importing interfaces represented 38.1 percent of the total net PJM scheduled imports in the real-time energy market.[6]

6 In the real-time energy market, one PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP)). CWLP is a balancing authority on the western side of MISO.

Table 9-3 Real-time scheduled net interchange volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(181.1)	(25.4)	(49.1)	47.3	33.7	(29.3)	(42.4)	21.3	9.7	(215.2)
CPLW	0.0	0.0	0.0	0.5	0.0	0.1	0.0	0.0	(0.8)	(0.1)
DUK	(132.8)	340.7	91.3	294.4	227.6	56.4	(5.2)	200.5	268.6	1,341.5
LGEE	(10.7)	(44.1)	(103.5)	(37.7)	(41.5)	(85.5)	(89.9)	(123.4)	(89.3)	(625.5)
MISO	(735.0)	(875.9)	(1,261.2)	(698.1)	(1,923.9)	(1,995.2)	(2,257.9)	(3,225.4)	(2,080.2)	(15,052.8)
ALTE	(123.6)	(143.9)	(154.2)	(42.5)	(207.1)	(238.2)	(330.7)	(448.1)	(156.5)	(1,844.8)
ALTW	(6.9)	(6.6)	(13.5)	10.0	(15.9)	(22.3)	(23.2)	(52.3)	(40.9)	(171.6)
AMIL	570.9	313.2	117.2	196.8	14.5	(43.5)	(30.7)	(55.0)	(24.7)	1,058.8
CIN	(789.3)	(574.9)	(600.0)	(145.3)	(619.1)	(749.9)	(1,092.3)	(1,331.6)	(751.2)	(6,653.6)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	60.7	5.5	57.0	78.1	(54.3)	18.8	18.6	(24.1)	(8.2)	152.0
MEC	(425.0)	(333.2)	(402.7)	(575.1)	(633.3)	(571.4)	(507.6)	(624.6)	(614.3)	(4,687.0)
MECS	156.7	(23.6)	(113.0)	55.7	(209.1)	(223.3)	(157.1)	(434.2)	(312.4)	(1,260.3)
NIPS	(72.7)	(45.6)	(74.8)	(278.0)	(103.8)	(64.6)	(48.5)	(59.6)	(52.2)	(799.7)
WEC	(105.7)	(66.8)	(77.2)	2.1	(95.9)	(100.8)	(86.4)	(196.0)	(119.7)	(846.5)
NYISO	(1,867.7)	(2,237.3)	(2,076.2)	(1,260.6)	(1,451.9)	(1,476.9)	(1,742.0)	(1,982.1)	(1,775.5)	(15,870.2)
HUDS	(173.6)	(275.1)	(342.4)	(258.9)	(178.4)	(368.7)	(456.8)	(438.3)	(410.0)	(2,902.2)
LIND	(210.9)	(209.6)	(221.1)	(148.8)	(210.8)	(206.6)	(229.0)	(227.7)	(203.3)	(1,867.7)
NEPT	(493.1)	(450.8)	(478.2)	(419.7)	(400.4)	(471.1)	(501.0)	(471.4)	(473.3)	(4,158.9)
NYIS	(990.1)	(1,301.9)	(1,034.6)	(433.2)	(662.3)	(430.5)	(555.1)	(844.7)	(688.9)	(6,941.4)
TVA	(97.2)	85.5	185.0	(11.5)	223.8	(71.7)	41.2	45.1	221.3	621.5
Total	(3,024.5)	(2,756.5)	(3,213.6)	(1,665.8)	(2,932.2)	(3,602.1)	(4,096.1)	(5,063.9)	(3,446.1)	(29,800.7)

Table 9-4 Real-time scheduled gross import volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	6.4	59.7	19.5	78.0	65.5	20.1	9.4	48.4	54.8	361.9
CPLW	0.0	0.0	0.0	0.5	0.0	0.1	0.0	0.0	0.1	0.8
DUK	184.5	403.1	256.8	376.5	318.3	180.2	243.4	315.4	349.4	2,627.6
LGEE	110.3	55.6	24.8	50.5	13.6	34.2	41.9	9.1	1.4	341.3
MISO	1,169.2	550.5	495.7	813.5	333.7	376.1	404.1	235.7	293.7	4,672.1
ALTE	15.4	7.1	13.3	36.9	10.3	32.6	21.5	11.0	6.3	154.4
ALTW	12.2	11.7	14.6	27.7	7.3	18.0	8.7	5.8	5.5	111.5
AMIL	574.1	325.4	127.7	225.0	122.2	28.0	10.6	7.5	11.7	1,432.1
CIN	131.5	40.5	76.3	159.8	42.7	88.1	113.8	82.6	128.1	863.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	63.0	19.1	80.0	96.4	50.2	59.4	49.4	32.1	46.4	495.9
MEC	62.0	53.0	56.0	47.4	40.4	29.6	36.2	29.6	20.0	374.1
MECS	265.4	72.9	94.8	164.0	40.4	110.7	127.6	58.6	63.1	997.5
NIPS	(0.7)	(0.7)	(0.8)	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	0.9	(5.1)
WEC	46.4	21.6	33.7	57.0	21.0	10.5	37.0	9.3	11.7	248.1
NYISO	146.7	112.6	145.9	110.3	119.4	154.9	152.8	135.1	98.2	1,176.0
HUDS	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
LIND	1.3	0.0	0.9	0.1	0.0	0.2	0.0	0.0	0.4	2.9
NEPT	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.3
NYIS	145.4	112.5	144.9	110.2	119.4	154.6	152.8	135.0	97.6	1,172.4
TVA	294.6	392.4	293.9	413.5	367.4	251.6	399.8	325.5	410.4	3,149.0
Total	1,911.6	1,573.9	1,236.6	1,842.8	1,217.9	1,017.1	1,251.4	1,069.2	1,208.0	12,328.6

Table 9-5 Real-time scheduled gross export volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	187.5	85.1	68.6	30.7	31.8	49.4	51.8	27.1	45.1	577.1
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9
DUK	317.3	62.4	165.5	82.1	90.7	123.8	248.6	114.9	80.8	1,286.0
LGEE	120.9	99.7	128.3	88.2	55.2	119.7	131.7	132.5	90.7	966.8
MISO	1,904.2	1,426.4	1,756.8	1,511.6	2,257.6	2,371.3	2,662.0	3,461.1	2,373.8	19,724.8
ALTE	139.0	151.0	167.5	79.4	217.4	270.8	352.2	459.1	162.7	1,999.2
ALTW	19.1	18.4	28.1	17.7	23.1	40.3	32.0	58.1	46.4	283.1
AMIL	3.2	12.2	10.5	28.1	107.7	71.4	41.2	62.5	36.5	373.3
CIN	920.8	615.4	676.4	305.1	661.9	838.0	1,206.1	1,414.2	879.3	7,517.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	2.4	13.6	22.9	18.2	104.5	40.6	30.8	56.1	54.6	343.9
MEC	487.0	386.2	458.7	622.5	673.7	600.9	543.8	654.1	634.3	5,061.2
MECS	108.7	96.4	207.9	108.3	249.5	334.0	284.8	492.9	375.4	2,257.8
NIPS	72.0	44.9	74.0	277.3	103.0	63.9	47.7	58.8	53.1	794.6
WEC	152.2	88.4	110.8	55.0	116.8	111.3	123.4	205.2	131.4	1,094.6
NYISO	2,014.4	2,349.9	2,222.1	1,371.0	1,571.3	1,631.8	1,894.7	2,117.2	1,873.7	17,046.1
HUDS	173.6	275.2	342.4	258.9	178.4	368.7	456.8	438.4	410.1	2,902.5
LIND	212.1	209.6	221.9	148.9	210.8	206.8	229.0	227.7	203.7	1,870.6
NEPT	493.1	450.8	478.3	419.7	400.4	471.1	501.0	471.5	473.4	4,159.2
NYIS	1,135.5	1,414.4	1,179.5	543.4	781.7	585.2	707.9	979.6	786.5	8,113.8
TVA	391.8	306.9	108.9	425.0	143.5	323.4	358.6	280.4	189.1	2,527.5
Total	4,936.0	4,330.4	4,450.2	3,508.6	4,150.2	4,619.2	5,347.6	6,133.1	4,654.1	42,129.3

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a path on which scheduled imports or exports will flow.[7] 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, 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 SOUTH 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.[8]

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.[9] 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 9-20 presents the interface pricing points used in the first nine months of 2025. On October 21, 2020, PJM updated the mappings of external balancing authorities to individual pricing points. Figure 9-4 shows a map of the default interface pricing point assignments for all external balancing authorities. Figure 9-4 shows that the balancing authorities in the Western Interconnection are mapped to either the MISO interface pricing point or the SOUTH interface pricing point. This determination was made by PJM based on geographic location rather than the electrical impact on the PJM system. When power is scheduled across a DC tie line, its effects on the PJM system are as if a generator is located at the point

7 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.

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

9 See "Interface Pricing Point Assignment Methodology," (May 7, 2025) <https://www.pjm.com/-/media/DotCom/etools/exschedule/interface-pricing-point-assignment-methodology.pdf>. PJM periodically updates these definitions on its website.

in the Eastern Interconnection where the DC tie line connects. The electrical impact on PJM tie lines from sources in the Western Interconnection differ based on the relevant DC tie line and could vary from the MISO interface pricing point to the SOUTH interface pricing point. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM rather than geographical location. The MMU recommends that PJM review the mappings of external balancing authority pricing points at least annually to reflect the fact that changes to the system topology can affect the electrical impact of external power sources on PJM.

The MMU has made multiple recommendations to either retire or consolidate interface pricing points used by PJM. The reasons for those recommendations include: pricing points that could no longer be used to price actual transactions; pricing points that were inappropriately used to support special agreements; pricing points that were treated as multiple pricing points when they were a single pricing point; and pricing points that were noncontiguous to the PJM footprint that created opportunities for sham scheduling. Table 9-6 shows the interface pricing points, the recommendation and the date the recommendation was adopted.

Table 9-6 MMU interface pricing point recommendations and dates adopted

Interface Pricing Point	Recommendation	Date Adopted
IMO	Retire Pricing Point - Noncontiguous	
Southeast (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
Southwest (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
SOUTHEXP	Consolidate Pricing Points	1-Jun-2021
SOUTHIMP	Consolidate Pricing Points	1-Jun-2021
Southeast	Retire Pricing Point - Support Special Agreements	15-Apr-2021
Southwest	Retire Pricing Point - Support Special Agreements	15-Apr-2021
NCMPAEXP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
NCMPAIMP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
Northwest	Retire Pricing Point - Noncontiguous	1-Oct-2020
CPLEEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
CPLEIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
NIPSCO	Retire Pricing Point - Obsolete (Integration into MISO)	1-Jun-2020
OVEC	Retire Pricing Point - Obsolete (Integration into PJM)	1-Dec-2018

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.[10] The MMU recommended 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. At the March 20, 2024, meeting of the Markets and Reliability Committee, PJM stakeholders approved the implementation of a new annual review of interface pricing definitions.[11] [12] The annual review evaluates, and adjusts as necessary, the interface pricing definitions to ensure the buses and weightings used in the interface pricing definitions capture changes in system topology over time and reflect current 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

10 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario interface pricing point.
11 *See* "Manual 11 Revisions – Interface Pricing Points Review," Presented at the PJM Markets and Reliability Committee (MRC) meeting held on March 20, 2024 <https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240320/20240320-consent-agenda-b---1-manual-11-revisions-interface-pricing-points---presentation.ashx>.
12 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 136 (October 1, 2025.

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.

In the real-time energy market, in the first nine months of 2025, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions. The top three net exporting interface pricing points in the real-time energy market accounted for 85.6 percent of the total net scheduled exports: PJM/MISO with 52.2 percent, PJM/NYIS with 20.9 percent and PJM/NEPTUNE with 12.5 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 47.8 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first nine months of 2025, there were net scheduled imports at two of PJM's seven interface pricing points eligible for real-time transactions. The top importing interface pricing point in the real-time energy market was the PJM/SOUTH interface pricing point, which accounted for 80.5 percent of the total 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.

Table 9-7 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	190.3	28.7	76.9	109.4	27.4	91.9	93.3	13.2	35.5	666.5
MISO	(1,550.7)	(1,168.6)	(1,486.9)	(1,136.8)	(2,067.2)	(2,125.5)	(2,422.4)	(3,252.4)	(2,142.5)	(17,353.0)
NYISO	(1,852.9)	(2,237.3)	(2,076.4)	(1,263.4)	(1,453.9)	(1,477.5)	(1,740.6)	(1,982.2)	(1,776.1)	(15,860.2)
HUDSONTP	(173.6)	(275.1)	(342.4)	(258.9)	(178.4)	(368.7)	(456.8)	(438.3)	(410.0)	(2,902.2)
LINDENVFT	(210.9)	(209.6)	(221.1)	(148.8)	(210.8)	(206.6)	(229.0)	(227.7)	(203.3)	(1,867.7)
NEPTUNE	(493.1)	(450.8)	(478.2)	(419.7)	(400.4)	(471.1)	(501.0)	(471.4)	(473.3)	(4,158.9)
NYIS	(975.3)	(1,301.9)	(1,034.8)	(436.0)	(664.3)	(431.1)	(553.7)	(844.8)	(689.5)	(6,931.4)
SOUTH	188.8	620.8	272.8	625.0	561.4	(90.9)	(26.5)	157.5	437.0	2,746.0
Total	(3,024.5)	(2,756.5)	(3,213.6)	(1,665.8)	(2,932.2)	(3,602.1)	(4,096.1)	(5,063.9)	(3,446.1)	(29,800.7)

Table 9-8 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	238.1	65.6	78.1	110.0	29.9	99.3	105.4	33.7	42.1	802.1
MISO	233.4	188.9	256.2	360.9	182.6	236.2	225.7	181.5	221.7	2,087.1
NYISO	146.3	111.8	145.6	107.4	117.1	153.2	152.1	134.8	97.6	1,165.9
HUDSONTP	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
LINDENVFT	1.3	0.0	0.9	0.1	0.0	0.2	0.0	0.0	0.4	2.9
NEPTUNE	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.3
NYIS	145.0	111.7	144.5	107.2	117.1	153.0	152.1	134.7	97.0	1,162.4
SOUTH	1,293.8	1,207.7	756.8	1,264.5	888.3	528.4	768.2	719.2	846.7	8,273.4
Total	1,911.6	1,573.9	1,236.6	1,842.8	1,217.9	1,017.1	1,251.4	1,069.2	1,208.0	12,328.6

Table 9-9 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	47.8	36.9	1.2	0.6	2.5	7.4	12.1	20.4	6.6	135.6
MISO	1,784.1	1,357.4	1,743.1	1,497.7	2,249.8	2,361.8	2,648.1	3,434.0	2,364.2	19,440.2
NYISO	1,999.2	2,349.1	2,222.0	1,370.8	1,571.0	1,630.7	1,892.7	2,117.0	1,873.7	17,026.1
HUDSONTP	173.6	275.2	342.4	258.9	178.4	368.7	456.8	438.4	410.1	2,902.5
LINDENVFT	212.1	209.6	221.9	148.9	210.8	206.8	229.0	227.7	203.7	1,870.6
NEPTUNE	493.1	450.8	478.3	419.7	400.4	471.1	501.0	471.5	473.4	4,159.2
NYIS	1,120.3	1,413.6	1,179.3	543.3	781.4	584.1	705.9	979.5	786.5	8,093.8
SOUTH	1,105.0	587.0	483.9	639.4	326.9	619.3	794.7	561.6	409.6	5,527.4
Total	4,936.0	4,330.4	4,450.2	3,508.6	4,150.2	4,619.2	5,347.6	6,133.1	4,654.1	42,129.3

Day-Ahead Interface Imports and Exports

In the day-ahead energy market, as in the real-time energy market, scheduled imports and exports are determined by the scheduled 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.[13] 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.[14]

In the day-ahead energy market, transaction sources and sinks are determined solely by market participants. In Table 9-10, Table 9-11, and Table 9-12, 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 SOUTH 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 SOUTH 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 appear as scheduled through the SOUTH interface pricing point, which reflects the expected power flow.

Table 9-10 through Table 9-12 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 nine months of 2025 in Table 9-10, while gross scheduled imports and exports are shown in Table 9-11 and Table 9-12.

In the day-ahead energy market, in the first nine months of 2025, there were net scheduled exports at 15 of PJM's 19 interfaces. The top three net exporting

13 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.
14 See the *2010 Annual State of the Market Report for PJM*, Volume 2, Section 4, "Interchange Transactions," for details.

interfaces in the day-ahead energy market accounted for 53.1 percent of the total net scheduled exports: PJM/NYISO (NYIS) with 21.9 percent, PJM/MidAmerican Energy Company (MEC) with 15.9 percent and PJM/Neptune (NEPT) with 15.3 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 50.2 percent of the total net PJM scheduled exports in the day-ahead energy market. In the first nine months of 2025, there were net exports in the day-ahead energy market at eight of the 10 separate interfaces that connect PJM to MISO. Those eight interfaces represented 39.3 percent of the total net PJM exports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2025, there were net scheduled imports at two of PJM's 19 interfaces. The top importing interface in the day-ahead energy market was the Duke (DUK) Interface, which accounted for 70.0 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 nine months of 2025, there were net imports in the day-ahead energy market at one of the 10 separate interfaces that connect PJM to MISO (Indianapolis Power & Light). That interface represented 30.0 percent of the total net PJM imports in the day-ahead energy market.[15]

Table 9-10 Day-ahead scheduled net interchange volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(66.5)	(24.2)	(59.4)	(8.8)	(9.7)	(32.4)	(38.1)	(9.2)	(21.8)	(270.1)
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	(87.2)	106.4	(21.5)	6.0	49.9	5.8	16.7	36.3	75.0	187.5
LGEE	(123.6)	(99.6)	(127.6)	(87.9)	(56.3)	(115.7)	(116.2)	(136.1)	(94.6)	(957.5)
MISO	(949.4)	(897.0)	(929.6)	(943.6)	(1,283.6)	(1,346.1)	(1,439.5)	(1,733.7)	(1,288.7)	(10,811.1)
ALTE	(53.6)	(51.0)	(79.0)	(25.9)	(149.9)	(192.7)	(192.4)	(114.0)	(39.3)	(897.8)
ALTW	(13.2)	(16.7)	(11.7)	(1.9)	(23.6)	(35.7)	(24.8)	(45.4)	(36.8)	(209.8)
AMIL	0.0	0.0	0.0	0.0	0.0	(1.0)	0.0	0.0	(0.5)	(1.5)
CIN	(351.8)	(420.6)	(381.9)	(153.0)	(408.6)	(417.1)	(606.4)	(836.2)	(534.4)	(4,110.1)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	3.7	27.3	0.4	0.5	20.5	12.3	15.5	80.2
MEC	(408.5)	(331.5)	(348.7)	(507.3)	(585.1)	(589.9)	(516.2)	(549.2)	(560.5)	(4,396.9)
MECS	14.1	(9.0)	(22.4)	(24.8)	(3.9)	(5.3)	(9.5)	(41.1)	(34.3)	(136.4)
NIPS	(23.8)	(12.3)	(16.7)	(240.3)	(17.0)	(18.9)	(19.8)	(17.8)	(10.3)	(377.0)
WEC	(112.6)	(55.8)	(72.8)	(17.6)	(95.8)	(86.0)	(91.0)	(142.2)	(88.0)	(761.8)
NYISO	(1,605.1)	(1,982.1)	(1,928.0)	(1,131.6)	(1,260.0)	(1,345.7)	(1,531.0)	(1,690.4)	(1,433.1)	(13,906.9)
HUDS	(170.4)	(272.3)	(362.5)	(262.8)	(166.8)	(358.2)	(456.0)	(427.9)	(411.0)	(2,887.9)
LIND	(74.8)	(82.0)	(84.1)	(51.0)	(80.2)	(79.8)	(91.0)	(96.2)	(71.6)	(710.9)
NEPT	(484.9)	(454.3)	(494.4)	(436.3)	(416.0)	(482.8)	(501.4)	(490.3)	(480.0)	(4,240.3)
NYIS	(874.9)	(1,173.6)	(986.9)	(381.5)	(597.0)	(424.9)	(482.7)	(676.0)	(470.6)	(6,067.9)
TVA	(298.0)	(190.8)	(87.9)	(309.0)	(28.4)	(221.2)	(242.2)	(205.3)	(88.6)	(1,671.4)
Total without Up To Congestion	(3,129.7)	(3,087.2)	(3,153.9)	(2,474.9)	(2,588.0)	(3,055.3)	(3,350.4)	(3,738.4)	(2,851.7)	(27,429.6)
Up To Congestion	(237.1)	211.1	91.2	180.8	50.6	297.1	411.9	373.8	(180.4)	1,199.0
Total	(3,366.8)	(2,876.2)	(3,062.7)	(2,294.2)	(2,537.4)	(2,758.2)	(2,938.4)	(3,364.6)	(3,032.1)	(26,230.6)

15 In the day-ahead energy market, two PJM interfaces had a net interchange of zero (PJM/Carolina Power and Light West (CPLW and PJM/City Water Light & Power (CWLP)).

Table 9-11 Day-ahead scheduled gross import volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	1.0	17.2	0.0	16.3	14.0	3.1	0.0	10.7	12.2	74.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	42.2	130.2	74.3	45.7	76.5	50.7	80.4	70.4	97.6	668.0
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.0	1.6
MISO	50.9	20.3	56.7	88.8	16.3	35.0	56.8	19.2	54.5	398.5
ALTE	5.4	3.7	7.6	6.7	5.0	2.6	1.4	0.7	1.5	34.7
ALTW	1.3	0.3	8.2	10.0	0.0	5.9	6.1	2.0	2.9	36.7
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	27.9	3.5	32.3	20.0	9.3	25.6	18.7	2.6	24.1	164.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	3.7	27.3	0.4	0.5	20.5	13.6	19.4	85.3
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MECS	15.3	0.1	1.2	0.8	0.0	0.4	3.2	0.3	4.9	26.2
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	1.0	12.7	3.7	24.1	1.6	0.0	6.9	0.0	1.7	51.6
NYISO	32.7	0.9	0.6	3.9	3.3	10.5	4.3	0.3	0.5	56.9
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.7	0.0	0.0	0.1	0.0	0.3	0.0	0.0	0.5	1.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	32.0	0.9	0.6	3.8	3.3	10.2	4.3	0.3	0.0	55.2
TVA	11.0	69.3	5.7	98.3	93.5	32.1	69.2	51.8	56.0	487.1
Total without Up To Congestion	137.8	237.8	137.3	253.0	203.7	131.4	210.8	154.0	220.7	1,686.5
Up To Congestion	572.1	893.3	831.6	547.2	483.9	671.9	753.2	802.0	404.4	5,959.6
Total	710.0	1,131.1	968.8	800.3	687.6	803.3	964.0	956.0	625.0	7,646.1

Table 9-12 Day-ahead scheduled gross export volume by interface (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	67.5	41.4	59.4	25.1	23.7	35.5	38.2	20.0	33.9	344.6
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	129.4	23.8	95.8	39.8	26.5	44.9	63.7	34.1	22.6	480.6
LGEE	123.6	99.6	127.6	87.9	56.3	115.7	116.2	137.6	94.6	959.0
MISO	1,000.3	917.2	986.3	1,032.4	1,299.9	1,381.1	1,496.3	1,753.0	1,343.1	11,209.6
ALTE	59.0	54.7	86.7	32.6	155.0	195.2	193.8	114.7	40.8	932.5
ALTW	14.5	17.0	19.9	11.9	23.6	41.6	30.9	47.4	39.7	246.4
AMIL	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.5	1.5
CIN	379.7	424.1	414.2	173.0	417.9	442.8	625.1	838.8	558.5	4,274.1
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	3.9	5.1
MEC	408.5	331.5	348.7	507.3	585.1	589.9	516.2	549.2	560.5	4,396.9
MECS	1.2	9.1	23.6	25.6	4.0	5.7	12.6	41.4	39.2	162.6
NIPS	23.8	12.3	16.7	240.3	17.0	18.9	19.8	17.8	10.3	377.0
WEC	113.6	68.5	76.5	41.7	97.4	86.0	97.9	142.2	89.7	813.5
NYISO	1,637.8	1,983.0	1,928.5	1,135.5	1,263.3	1,356.3	1,535.3	1,690.6	1,433.6	13,963.8
HUDS	170.4	272.3	362.5	262.8	166.8	358.2	456.0	427.9	411.0	2,887.9
LIND	75.6	82.0	84.1	51.1	80.2	80.1	91.0	96.2	72.1	712.5
NEPT	484.9	454.3	494.4	436.3	416.0	482.8	501.4	490.3	480.0	4,240.3
NYIS	906.9	1,174.4	987.5	385.3	600.3	435.1	486.9	676.3	470.6	6,123.1
TVA	308.9	260.1	93.6	407.4	121.9	253.3	311.4	257.2	144.6	2,158.4
Total without Up To Congestion	3,267.5	3,325.0	3,291.2	2,727.9	2,791.7	3,186.8	3,561.2	3,892.4	3,072.4	29,116.1
Up To Congestion	809.2	682.3	740.3	366.5	433.3	374.7	341.3	428.2	584.8	4,760.6
Total	4,076.8	4,007.3	4,031.5	3,094.4	3,225.0	3,561.5	3,902.4	4,320.6	3,657.2	33,876.7

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-13 through Table 9-18 show the day-ahead scheduled interchange totals at the interface pricing points. In the first nine months of 2025, up to congestion transactions accounted for 77.9 percent of all scheduled import MW transactions and 14.1 percent of all scheduled export MW transactions in the day-ahead energy market. The day-ahead net scheduled interchange in the first nine months of 2025, including up to congestion transactions, is shown by interface pricing point in Table 9-13. Scheduled up to congestion transactions by interface pricing point in the first nine months of 2025 are shown in Table 9-14. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-15 and Table 9-17, while gross scheduled import and export up to congestion transactions are shown in Table 9-16 and Table 9-18.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. 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 nine months of 2025, there were net scheduled exports at six of PJM's seven interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the day-ahead energy market accounted for 78.6 percent of the total net scheduled exports: PJM/MISO with 36.8 percent, PJM/NYIS with 26.0 percent and PJM/NEPTUNE (NEPT) with 15.8 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 59.2 percent of the total net PJM scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2025, there were net scheduled imports at one of PJM's seven interface pricing points eligible for day-ahead transactions, (Ontario Independent Electricity System Operator (IMO)), which accounted for 100.0 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 day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2025, up to congestion transactions had net scheduled exports at three of PJM's seven interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 87.9 percent of the total net up to congestion scheduled exports: PJM/NYIS with 44.6 percent and PJM/HUDSONTP with 43.3 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 100.0 percent of the total net scheduled up to congestion exports in the day-ahead energy market. However, the PJM/NEPTUNE interface pricing point had net up to congestion scheduled imports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2025, up to congestion transactions had net scheduled imports at four of PJM's seven interface pricing points eligible for day-ahead transactions. The top two importing interface pricing points eligible for up to congestion transactions accounted for 95.6 percent of the total up to congestion scheduled imports: PJM/SOUTH with 57.1 percent and PJM/MISO with 38.6 percent of the net up to congestion scheduled 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 2.8 percent of the total net scheduled up to congestion imports in the day-ahead energy market. However, the PJM/HUDSONTP, PJM/LINDENVFT and PJM/NYIS interface pricing points had net up to congestion scheduled exports in the day-ahead energy market.

Table 9-13 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	(29.4)	32.3	1.7	5.5	(8.7)	21.2	10.2	27.5	5.4	65.7
MISO	(921.5)	(817.6)	(910.6)	(927.7)	(1,280.1)	(1,121.2)	(1,041.1)	(1,352.7)	(1,297.8)	(9,670.3)
NYISO	(1,820.3)	(2,221.0)	(2,306.1)	(1,236.2)	(1,359.3)	(1,480.2)	(1,640.6)	(1,808.9)	(1,689.6)	(15,562.2)
HUDSONTP	(283.5)	(478.9)	(484.5)	(314.8)	(191.3)	(406.7)	(493.4)	(487.8)	(501.9)	(3,643.0)
LINDENVFT	(110.8)	(138.1)	(135.4)	(60.3)	(82.8)	(91.4)	(95.3)	(103.2)	(104.8)	(922.1)
NEPTUNE	(482.1)	(427.9)	(477.2)	(425.1)	(426.1)	(486.3)	(490.5)	(472.4)	(471.5)	(4,159.1)
NYIS	(943.9)	(1,176.1)	(1,208.9)	(435.9)	(659.2)	(495.9)	(561.4)	(745.4)	(611.4)	(6,838.0)
SOUTH	(595.6)	130.1	152.3	(135.8)	110.7	(177.9)	(267.0)	(230.5)	(50.2)	(1,063.9)
Total	(3,366.8)	(2,876.2)	(3,062.7)	(2,294.2)	(2,537.4)	(2,758.2)	(2,938.4)	(3,364.6)	(3,032.1)	(26,230.6)

Table 9-14 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	(45.5)	39.3	1.0	4.8	(8.7)	18.8	6.1	29.5	2.0	47.3
MISO	18.4	65.4	19.7	17.8	8.1	227.3	407.2	376.8	(5.7)	1,135.0
NYISO	(216.5)	(238.9)	(378.1)	(104.7)	(103.9)	(134.5)	(110.2)	(118.5)	(256.5)	(1,661.8)
HUDSONTP	(113.1)	(206.7)	(122.0)	(52.0)	(24.5)	(48.5)	(37.4)	(60.0)	(90.9)	(755.1)
LINDENVFT	(35.9)	(56.1)	(51.3)	(9.3)	(2.6)	(11.6)	(4.3)	(7.0)	(33.1)	(211.2)
NEPTUNE	2.8	26.4	17.3	11.1	(10.1)	(3.4)	10.9	17.8	8.4	81.2
NYIS	(70.3)	(2.5)	(222.0)	(54.5)	(66.7)	(71.1)	(79.4)	(69.4)	(140.8)	(776.7)
SOUTH	6.6	345.2	448.6	262.8	155.1	185.6	108.8	86.0	79.8	1,678.5
Total Interfaces	(237.1)	211.1	91.2	180.8	50.6	297.1	411.9	373.8	(180.4)	1,199.0
INTERNAL	6,876.8	6,633.5	6,391.0	5,294.5	5,044.3	6,988.4	6,118.3	5,580.2	6,174.4	55,101.4
Total	6,639.7	6,844.6	6,482.3	5,475.2	5,094.9	7,285.5	6,530.2	5,954.0	5,994.0	56,300.5

Table 9-15 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	48.1	60.7	16.4	11.6	13.5	29.2	24.1	39.8	30.2	273.7
MISO	161.6	277.7	243.4	285.1	238.0	377.4	516.7	536.4	249.0	2,885.3
NYISO	151.9	172.5	129.3	45.2	52.0	71.0	100.7	104.6	77.2	904.3
HUDSONTP	7.1	4.4	26.9	8.9	13.3	8.6	16.5	13.6	18.1	117.3
LINDENVFT	6.1	13.0	22.9	4.9	5.7	6.2	14.6	19.8	8.7	102.1
NEPTUNE	19.1	43.3	50.9	18.1	4.2	10.9	17.4	24.8	19.6	208.4
NYIS	119.5	111.8	28.6	13.3	28.7	45.2	52.2	46.4	30.9	476.5
SOUTH	348.4	620.2	579.7	458.3	384.2	325.7	322.4	275.2	268.7	3,582.9
Total	710.0	1,131.1	968.8	800.3	687.6	803.3	964.0	956.0	625.0	7,646.1

Table 9-16 Up to congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	30.4	60.6	15.8	10.9	13.5	26.4	18.4	39.5	25.3	240.7
MISO	128.4	257.5	187.4	198.8	221.7	345.2	472.5	517.5	199.4	2,528.4
NYISO	119.1	171.6	128.7	41.3	48.7	60.4	96.4	104.3	76.7	847.4
HUDSONTP	7.1	4.4	26.9	8.9	13.3	8.6	16.5	13.6	18.1	117.3
LINDENVFT	5.4	13.0	22.9	4.8	5.7	5.9	14.6	19.8	8.2	100.5
NEPTUNE	19.1	43.3	50.9	18.1	4.2	10.9	17.4	24.8	19.6	208.4
NYIS	87.5	110.9	28.0	9.5	25.4	34.9	47.9	46.1	30.9	421.2
SOUTH	294.2	403.6	499.6	296.2	200.1	239.8	165.9	140.7	102.9	2,343.1
Total Interfaces	572.1	893.3	831.6	547.2	483.9	671.9	753.2	802.0	404.4	5,959.6

Table 9-17 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	77.5	28.4	14.7	6.1	22.2	8.1	13.9	12.4	24.8	208.0
MISO	1,083.1	1,095.3	1,154.0	1,212.8	1,518.1	1,498.6	1,557.9	1,889.1	1,546.7	12,555.5
NYISO	1,972.2	2,393.4	2,435.4	1,281.5	1,411.3	1,551.2	1,741.3	1,913.4	1,766.8	16,466.4
HUDSONTP	290.6	483.3	511.4	323.7	204.6	415.3	509.9	501.4	520.0	3,760.2
LINDENVFT	116.9	151.1	158.4	65.3	88.5	97.6	109.9	123.1	113.4	1,024.2
NEPTUNE	501.2	471.2	528.1	443.3	430.3	497.2	507.9	497.2	491.1	4,367.5
NYIS	1,063.4	1,287.8	1,237.5	449.2	687.9	541.0	613.6	791.8	642.3	7,314.5
SOUTH	944.0	490.1	427.5	594.1	273.5	503.7	589.4	505.7	318.9	4,646.8
Total	4,076.8	4,007.3	4,031.5	3,094.4	3,225.0	3,561.5	3,902.4	4,320.6	3,657.2	33,876.7

Table 9-18 Up to congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	75.9	21.3	14.7	6.1	22.2	7.6	12.3	10.0	23.3	193.5
MISO	110.0	192.1	167.7	181.0	213.6	117.9	65.3	140.7	205.1	1,393.4
NYISO	335.7	410.5	506.8	146.0	152.5	195.0	206.6	222.8	333.2	2,509.2
HUDSONTP	120.2	211.0	148.9	60.9	37.8	57.1	53.9	73.5	109.0	872.4
LINDENVFT	41.3	69.1	74.2	14.1	8.3	17.5	18.9	26.8	41.4	311.7
NEPTUNE	16.3	17.0	33.7	7.0	14.3	14.3	6.5	6.9	11.1	127.2
NYIS	157.8	113.4	250.0	64.0	92.1	106.0	127.3	115.5	171.7	1,197.9
SOUTH	287.6	58.3	51.1	33.4	45.0	54.2	57.0	54.7	23.2	664.6
Total Interfaces	809.2	682.3	740.3	366.5	433.3	374.7	341.3	428.2	584.8	4,760.6

Table 9-19 Active scheduling interfaces: January through September, 2025[16]

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

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

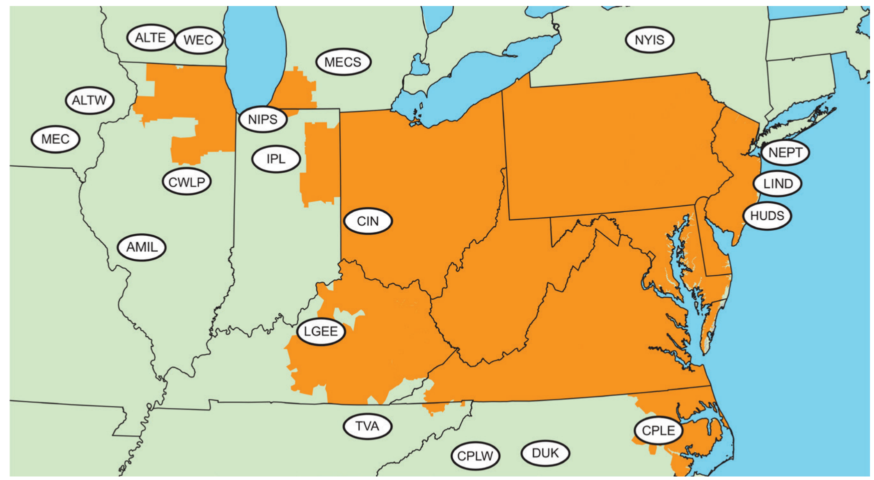
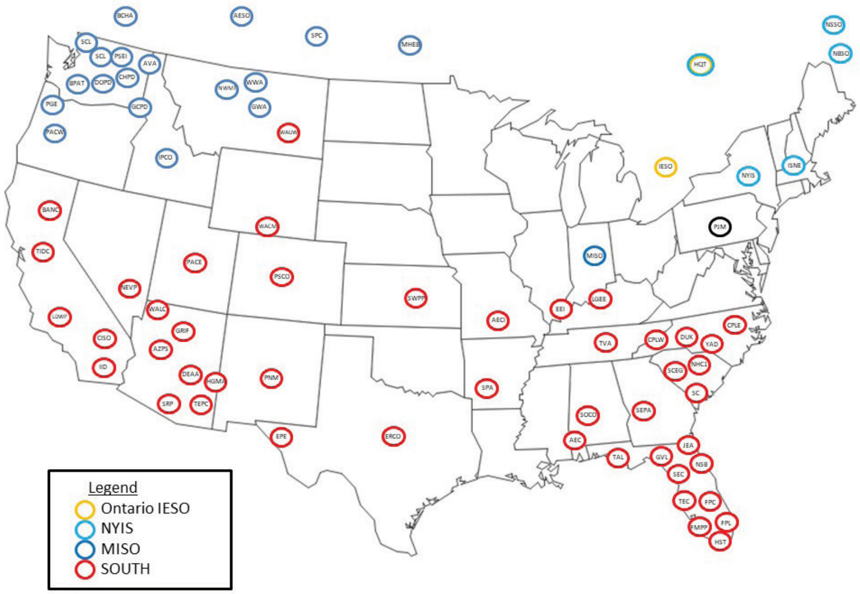


Table 9-20 Active scheduled interface pricing points: January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HUDSONTP	Active	Active	Active	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTH	Active	Active	Active	Active	Active	Active	Active	Active	Active

16 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of September 30, 2025, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM 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.[17]

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

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 SOUTH 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/SOUTH interface border, but there would be 100 MW of actual flows on the interface. In the first nine months of 2025, of the 2,746.0 GWh of net scheduled interchange that received the SOUTH interface pricing point, 1,622.6 GWh (59.1 percent) were scheduled through MISO. There were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In the first nine months of 2025, net scheduled interchange was -29,800.7 GWh and net actual interchange was -29,592.4 GWh, a difference of 208.4 GWh. In the first nine months of 2024, net scheduled interchange was -27,542.0 GWh and net actual interchange was -27,738.4 GWh, a difference of 196.4 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 by using unilateral or bilateral paybacks. Inadvertent interchange accumulations that are paid back unilaterally are paid by controlling to a non-zero area control error (ACE). For example, Table 9-21 shows that PJM had 208.4 GW of inadvertent interchange in the first nine months of 2025. To reduce this inadvertent interchange, PJM can control to an ACE less than zero, which would result in under generating. By way of the power balance equation, power would flow into PJM from its neighboring balancing authority areas. This would create decreased actual exports that were not scheduled, thus reducing the overall inadvertent. To maintain reliability, unilateral paybacks are accounted for in the control performance standard calculations. Bilateral paybacks are scheduled with other balancing authority areas by scheduling a correction and incorporating that amount as a bias in the energy management system.[18] [19]

Table 9-21 shows that in the first nine months of 2025, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -799.7 GWh of net scheduled interchange and -8,409.3 GWh of net actual interchange, a difference of 7,609.6 GWh.

18 See PJM. "Manual 12: Balancing Operations," Rev. 56 (October 1, 2025).
19 PJM does not publish data on inadvertent payback.

Table 9-21 Net scheduled and actual PJM flows by interface (GWh): January through September, 2025

Interface	Actual	Net Scheduled	Difference (GWh)
CPLE	881.9	(215.2)	1,097.1
CPLW	(109.2)	(0.1)	(109.1)
DUK	1,442.1	1,341.5	100.6
LGEE	1,318.1	(625.5)	1,943.6
MISO	(20,391.4)	(15,052.8)	(5,338.6)
ALTE	(805.4)	(1,844.8)	1,039.3
ALTW	(2,804.7)	(171.6)	(2,633.1)
AMIL	(3,472.6)	1,058.8	(4,531.3)
CIN	(3,291.7)	(6,653.6)	3,362.0
CWLP	(216.2)	0.0	(216.2)
IPL	(1,539.7)	152.0	(1,691.8)
MEC	(6,113.9)	(4,687.0)	(1,426.9)
MECS	3,497.7	(1,260.3)	4,758.0
NIPS	(8,409.3)	(799.7)	(7,609.6)
WEC	2,764.5	(846.5)	3,611.0
NYISO	(15,736.2)	(15,870.2)	134.0
HUDS	(2,902.2)	(2,902.2)	0.0
LIND	(1,867.7)	(1,867.7)	0.0
NEPT	(4,158.9)	(4,158.9)	0.0
NYIS	(6,807.4)	(6,941.4)	134.0
TVA	3,002.4	621.5	2,380.9
Total	(29,592.4)	(29,800.7)	208.4

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.[20] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SOUTH interface pricing point net schedule totals because SPP is mapped to the SOUTH 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.

20 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.

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 9-22 shows the net scheduled and actual PJM flows by interface pricing point.

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 9-22 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.

Table 9-22 shows that in the first nine months of 2025, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 2,746.0 GWh of net scheduled interchange and 6,535.3 GWh of net actual interchange, a difference of 3,789.3 GWh.

Table 9-22 PJM flows by interface pricing point (GWh): January through September, 2025

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
IMO	0.0	666.5	(666.5)
MISO	(20,391.4)	(17,353.0)	(3,038.4)
NYISO	(15,736.2)	(15,860.2)	124.0
HUDSONTP	(2,902.2)	(2,902.2)	0.0
LINDENVFT	(1,867.7)	(1,867.7)	0.0
NEPTUNE	(4,158.9)	(4,158.9)	0.0
NYIS	(6,807.4)	(6,931.4)	124.0
SOUTH	6,535.3	2,746.0	3,789.3
Total	(29,592.4)	(29,800.7)	208.4

Table 9-23 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.

Table 9-23 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through September, 2025

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
MISO	(20,391.4)	(16,676.5)	(3,714.9)
NYISO	(15,736.2)	(15,870.2)	134.0
HUDSONTP	(2,902.2)	(2,902.2)	0.0
LINDENVFT	(1,867.7)	(1,867.7)	0.0
NEPTUNE	(4,158.9)	(4,158.9)	0.0
NYIS	(6,807.4)	(6,941.4)	134.0
SOUTH	6,535.3	2,746.0	3,789.3
Total	(29,592.4)	(29,800.7)	208.4

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.

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 9-24 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 9-24 shows that in the first nine months of 2025, the majority of imports to the PJM energy market for which a market participant specified Michigan Electric Coordinated System (MECS) as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the IMO Interface, and thus actual flows were assigned the IMO interface pricing point (593.9 GWh). The majority of exports from the PJM energy market for which a market participant specified MECS 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 (-2,066.3 GWh).

Table 9-24 Net scheduled and actual flows by interface and interface pricing point (GWh): January through September, 2025

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(805.4)	(1,844.8)	1,039.3	LGEE		1,318.1	(625.5)	1,943.6
	IMO	0.0	1.1	(1.1)		SOUTH	1,318.1	(625.5)	1,943.6
	MISO	(805.4)	(1,839.0)	1,033.6	LIND		(1,867.7)	(1,867.7)	0.0
	SOUTH	0.0	(6.9)	6.9		LINDENVFT	(1,867.7)	(1,867.7)	0.0
ALTW		(2,804.7)	(171.6)	(2,633.1)	MEC		(6,113.9)	(4,687.0)	(1,426.9)
	IMO	0.0	14.0	(14.0)		IMO	0.0	(1.6)	1.6
	MISO	(2,804.7)	(196.6)	(2,608.1)		MISO	(6,113.9)	(4,676.8)	(1,437.1)
	SOUTH	0.0	11.0	(11.0)		SOUTH	0.0	(8.6)	8.6
AMIL		(3,472.6)	1,058.8	(4,531.3)	MECS		3,497.7	(1,260.3)	4,758.0
	MISO	(3,472.6)	(108.1)	(3,364.5)		IMO	0.0	593.9	(593.9)
	SOUTH	0.0	1,166.8	(1,166.8)		MISO	3,497.7	(2,066.3)	5,564.0
CIN		(3,291.7)	(6,653.6)	3,362.0		SOUTH	0.0	212.0	(212.0)
	IMO	0.0	(29.1)	29.1	NEPT		(4,158.9)	(4,158.9)	0.0
	MISO	(3,291.7)	(6,716.8)	3,425.1		NEPTUNE	(4,158.9)	(4,158.9)	0.0
	SOUTH	0.0	92.3	(92.3)	NIPS		(8,409.3)	(799.7)	(7,609.6)
CPLE		881.9	(215.2)	1,097.1		MISO	(8,409.3)	(799.7)	(7,609.6)
	SOUTH	881.9	(215.2)	1,097.1	NYIS		(6,807.4)	(6,941.4)	134.0
CPLW		(109.2)	(0.1)	(109.1)		IMO	0.0	(10.0)	10.0
	SOUTH	(109.2)	(0.1)	(109.1)		NYIS	(6,807.4)	(6,931.4)	124.0
CWLP		(216.2)	0.0	(216.2)	TVA		3,002.4	621.5	2,380.9
	MISO	(216.2)	0.0	(216.2)		MISO	0.0	(0.0)	0.0
DUK		1,442.1	1,341.5	100.6		SOUTH	3,002.4	621.5	2,380.9
	MISO	0.0	(1.1)	1.1	WEC		2,764.5	(846.5)	3,611.0
	SOUTH	1,442.1	1,342.6	99.5		MISO	2,764.5	(995.9)	3,760.4
HUDS		(2,902.2)	(2,902.2)	0.0		SOUTH	0.0	149.4	(149.4)
	HUDSONTP	(2,902.2)	(2,902.2)	0.0	Grand Total		(29,592.4)	(29,800.7)	208.4
IPL		(1,539.7)	152.0	(1,691.8)					
	IMO	0.0	98.2	(98.2)					
	MISO	(1,539.7)	47.2	(1,587.0)					
	SOUTH	0.0	6.6	(6.6)					

Table 9-25 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-24. Table 9-25 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-25 shows that in the first nine months of 2025, 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 SOUTH interface pricing point, had a path that entered the PJM energy market at the DUK Interface (1,342.6 GWh). The majority of exports from the PJM energy market for which a market participant specified a load control area for which it was assigned the SOUTH interface pricing point, had a path that would leave the PJM energy market at the LGEE Interface (-625.5 GWh).

Table 9-25 Net scheduled and actual flows by interface pricing point and interface (GWh): January through September, 2025

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
HUDSONTP		(2,902.2)	(2,902.2)	0.0	NEPTUNE		(4,158.9)	(4,158.9)	0.0
	HUDS	(2,902.2)	(2,902.2)	0.0		NEPT	(4,158.9)	(4,158.9)	0.0
IMO		0.0	666.5	(666.5)	NYIS		(6,807.4)	(6,931.4)	124.0
	ALTE	0.0	1.1	(1.1)		NYIS	(6,807.4)	(6,931.4)	124.0
	ALTW	0.0	14.0	(14.0)	SOUTH		6,535.3	2,746.0	3,789.3
	CIN	0.0	(29.1)	29.1		ALTE	0.0	(6.9)	6.9
	IPL	0.0	98.2	(98.2)		ALTW	0.0	11.0	(11.0)
	MEC	0.0	(1.6)	1.6		AMIL	0.0	1,166.8	(1,166.8)
	MECS	0.0	593.9	(593.9)		CIN	0.0	92.3	(92.3)
	NYIS	0.0	(10.0)	10.0		CPLE	881.9	(215.2)	1,097.1
LINDENVFT		(1,867.7)	(1,867.7)	0.0		CPLW	(109.2)	(0.1)	(109.1)
	LIND	(1,867.7)	(1,867.7)	0.0		DUK	1,442.1	1,342.6	99.5
MISO		(20,391.4)	(17,353.0)	(3,038.4)		IPL	0.0	6.6	(6.6)
	ALTE	(805.4)	(1,839.0)	1,033.6		LGEE	1,318.1	(625.5)	1,943.6
	ALTW	(2,804.7)	(196.6)	(2,608.1)		MEC	0.0	(8.6)	8.6
	AMIL	(3,472.6)	(108.1)	(3,364.5)		MECS	0.0	212.0	(212.0)
	CIN	(3,291.7)	(6,716.8)	3,425.1		TVA	3,002.4	621.5	2,380.9
	CWLP	(216.2)	0.0	(216.2)		WEC	0.0	149.4	(149.4)
	DUK	0.0	(1.1)	1.1	Grand Total		(29,592.4)	(29,800.7)	208.4
	IPL	(1,539.7)	47.2	(1,587.0)					
	MEC	(6,113.9)	(4,676.8)	(1,437.1)					
	MECS	3,497.7	(2,066.3)	5,564.0					
	NIPS	(8,409.3)	(799.7)	(7,609.6)					
	TVA	0.0	(0.0)	0.0					
	WEC	2,764.5	(995.9)	3,760.4					

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.[21]

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.[22]

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

21 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.
22 141 FERC ¶ 61,235 (2012).

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.

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 websites. 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.[23] The interface definitions led to questions about the level of congestion included in interchange pricing.

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

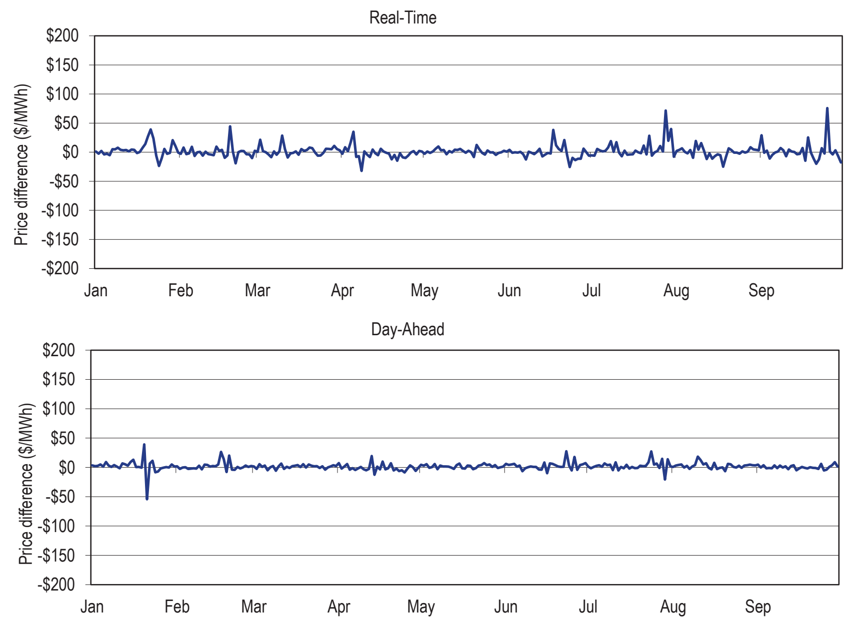
In the first nine months of 2025, the direction of flow was consistent with price differentials in 52.4 percent of the hours. Table 9-26 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Table 9-26 shows that PJM was a net exporter of energy to MISO in all but 125 hours during the first nine months of 2025. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first nine months of 2025, flows were in the uneconomic direction on the PJM/MISO interface in 47.6 percent of all hours. 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 9-30).

23 See "LMP Aggregate Definitions," (September 17, 2025) <https://www.pjm.com/-/media/DotCom/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.xlsx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

Table 9-26 PJM and MISO flow based hours and price differences: January through September, 2025

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	3,418	$15.02
	Consistent Flow (PJM to MISO)	3,362	$14.96
	Inconsistent Flow (MISO to PJM)	56	$18.75
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	3,133	$13.22
	Consistent Flow (MISO to PJM)	69	$13.27
	Inconsistent Flow (PJM to MISO)	3,064	$13.22
	No Flow	0	$0.00

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): January through September, 2025



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

Almost without exception, power flows from PJM to MISO regardless of the direction of price differences. In the first nine months of 2025, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 3,431 hours (52.4 percent of all hours), and was inconsistent with price differentials in 3,120 hours (47.6 percent of all hours). Table 9-27 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 3,120 hours where flows were in a direction inconsistent with price differences, 2,773 of those hours (88.9 percent) had a price difference greater than or equal to $1.00 and 1,745 of those hours (55.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,151.09. Of the 3,431 hours where flows were consistent with price differences, 3,022 of those hours (88.1 percent) had a price difference greater than or equal to $1.00 and 1,547 of all such hours (45.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,282.45.

Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through September, 2025

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	3,120	100.0%	3,431	100.0%
$1.00	2,773	88.9%	3,022	88.1%
$5.00	1,745	55.9%	1,547	45.1%
$10.00	1,079	34.6%	871	25.4%
$15.00	724	23.2%	614	17.9%
$20.00	510	16.3%	452	13.2%
$25.00	373	12.0%	380	11.1%
$50.00	128	4.1%	187	5.5%
$75.00	64	2.1%	108	3.1%
$100.00	44	1.4%	74	2.2%
$200.00	9	0.3%	36	1.0%
$300.00	5	0.2%	17	0.5%
$400.00	4	0.1%	11	0.3%
$500.00	4	0.1%	10	0.3%

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.[24]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. On May 1, 2017, PJM modified the PJM/NYIS interface price to be 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.

Prior to May 1, 2017, PJM's PJM/NYIS interface definition used two buses and included 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.

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

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

percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

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

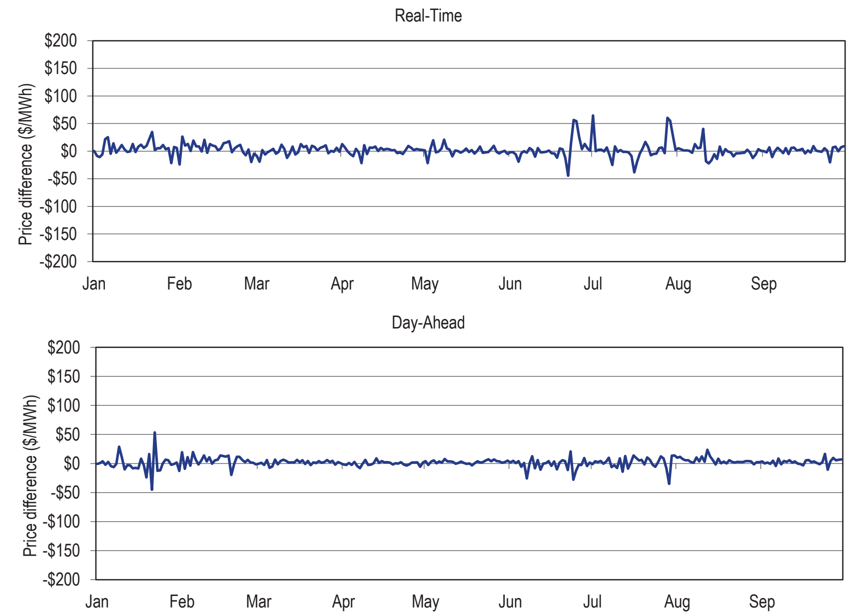
In the first nine months of 2025, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. The direction of flow was consistent with price differentials in 59.2 percent of the hours in the first nine months of 2025. Table 9-28 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 9-30).

Table 9-28 PJM and NYISO flow based hours and price differences: January through September, 2025[25]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	3,955	$16.45
	Consistent Flow (PJM to NYIS)	3,769	$14.47
	Inconsistent Flow (NYIS to PJM)	186	$56.49
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	2,596	$19.13
	Consistent Flow (NYIS to PJM)	108	$45.06
	Inconsistent Flow (PJM to NYIS)	2,488	$18.01
	No Flow	0	$0.00

25 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 September, 2025



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

In the first nine months of 2025, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,877 hours (59.2 percent of all hours), and was inconsistent with price differences in 2,674 hours (40.8 percent of all hours). Table 9-29 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 2,674 hours where flows were in a direction inconsistent with price differences, 2,456 of those hours (91.8 percent) had a price difference greater than or equal to $1.00 and 1,805 of all those hours (67.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $867.05. Of the 3,877 hours where flows were consistent with price differences, 3,646 of those hours (94.0 percent) had a price difference greater than or equal to $1.00 and 2,597 of all such hours (67.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,073.12.

Table 9-29 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through September, 2025

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	2,674	100.0%	3,877	100.0%
$1.00	2,456	91.8%	3,646	94.0%
$5.00	1,805	67.5%	2,597	67.0%
$10.00	1,245	46.6%	1,595	41.1%
$15.00	893	33.4%	1,016	26.2%
$20.00	678	25.4%	704	18.2%
$25.00	515	19.3%	553	14.3%
$50.00	209	7.8%	190	4.9%
$75.00	107	4.0%	87	2.2%
$100.00	70	2.6%	48	1.2%
$200.00	32	1.2%	14	0.4%
$300.00	20	0.7%	8	0.2%
$400.00	10	0.4%	6	0.2%
$500.00	5	0.2%	5	0.1%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-30, including average prices and measures of variability.

Table 9-30 PJM, NYISO and MISO border price averages: January through September, 2025[26]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$47.19	$38.04	$47.21	$38.54
	ISO Price at PJM Border	$49.61	$39.55	$49.15	$40.31
	Difference at Border (PJM-ISO)	($2.42)	($1.51)	($1.94)	($1.77)
	Average Absolute Value of Interval Difference at Border	$22.17	$18.68	$7.73	$6.21
	Sign Changes per Day	41.2	46.7	2.8	3.1
Standard Deviation	PJM Price at ISO Border	$68.54	$59.27	$34.66	$27.63
	ISO Price at PJM Border	$68.56	$80.39	$31.53	$26.65
	Difference at Border (PJM-ISO)	$69.40	$86.00	$12.64	$11.05

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 81.5 percent of the hours in the first nine months of 2025. Table 9-31 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.

Table 9-31 PJM and NYISO flow based hours and price differences (Neptune): January through September, 2025

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	5,463	$31.17
	Consistent Flow (PJM to NYIS)	5,337	$31.54
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	126	$15.54
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	1,088	$19.79
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,065	$20.07
	No Flow	23	$6.81

26 Effective April 1, 2018, PJM implemented five 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 per day. For the day-ahead market there are 24 hourly intervals per day.

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").[27] The PJM Out Service is covered by normal PJM OASIS business operations.[28] 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 September 30, 2025, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

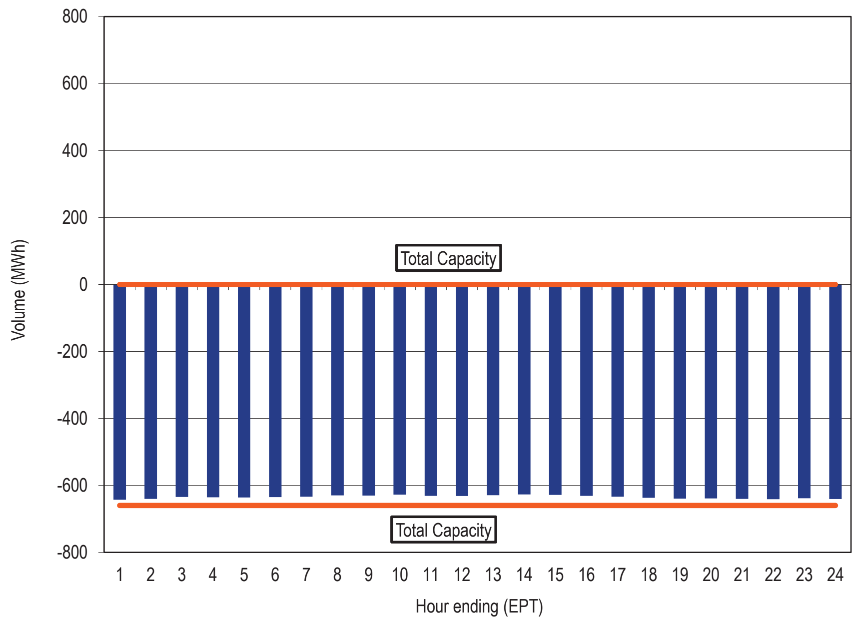
Table 9-32 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July 2007. Table 9-32 shows that in the first nine months of 2025, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in January through May, and in July through September and the primary rights holder was responsible for less than 100 percent of the scheduled interchange across the Neptune Line in June. Figure 9-7 shows the hourly average flow across the Neptune Line for the first nine months of 2025.

Table 9-32 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through September 2025

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
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%	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%	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%	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%	100.00%	100.00%	100.00%	100.00%	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%	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%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.41%
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%	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%	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%	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%	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%	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%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

27 See OASIS "PJM Business Practices for Neptune Transmission Service," (August 21, 2015) <https://www.pjm.com/-/media/DotCom/etools/oasis/merch-trans-facilities/neptune-oasis-business-practices-doc-clean.pdf>.
28 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 12 (July 26, 2023) <https://www.pjm.com/-/media/DotCom/etools/oasis/regional-practices-clean-pdf.pdf>.

Figure 9-7 Neptune hourly average flow: January through September, 2025



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 80.3 percent of the hours in the first nine months of 2025. Table 9-33 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 9-33 PJM and NYISO flow based hours and price differences (Linden): January through September, 2025

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	5,376	$26.86
	Consistent Flow (PJM to NYIS)	5,260	$26.92
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	116	$24.05
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	1,175	$40.31
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,166	$40.56
	No Flow	9	$7.82

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”).[29] The PJM Out Service is covered by normal PJM OASIS business operations.[30] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 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 1200 (EPT), one business day before the start of service. On September 30, 2025, 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.

29 See OASIS "PJM Business Practices for Linden VFT Transmission Service," (June 1, 2011) <https://www.pjm.com/-/media/DotCom/etools/oasis/merch-trans-facilities/linden-vft-oasis-business-practices-clean.pdf>.

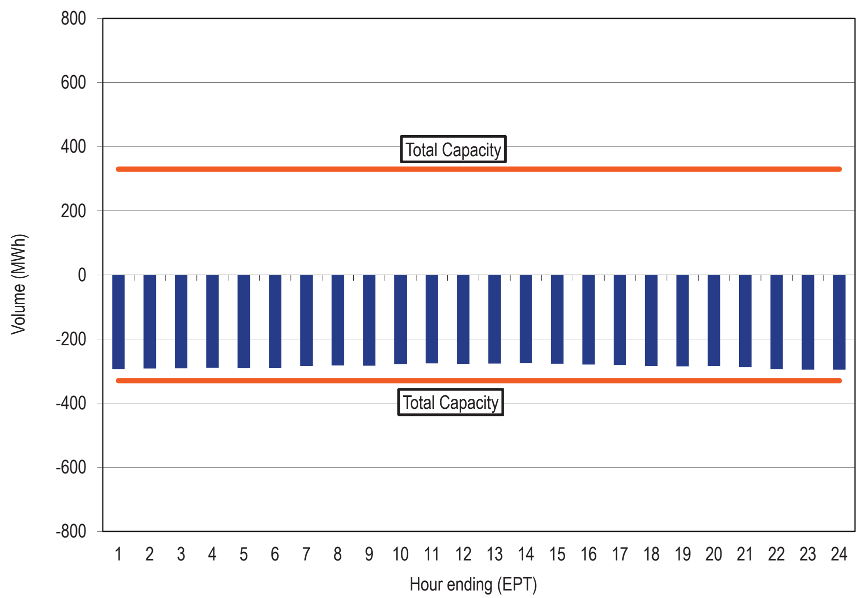
30 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 12 (July 26, 2023) <https://www.pjm.com/-/media/DotCom/etools/oasis/regional-practices-clean-pdf.pdf>.

Table 9-34 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-34 shows that in the first nine months of 2025, 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 nine months of 2025.

Table 9-34 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through September 2025

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	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%	94.95%	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%	96.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	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%	100.00%	100.00%	100.00%	100.00%	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%	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%	100.00%	100.00%	100.00%	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%	100.00%	100.00%	100.00%	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%	100.00%	100.00%	100.00%	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%	100.00%	100.00%	100.00%	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%	100.00%	100.00%	100.00%	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%	100.00%	100.00%	100.00%	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%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Figure 9-8 Linden hourly average flow: January through September, 2025[31]



31 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 80.7 percent of the hours in the first nine months of 2025. Table 9-35 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 9-35 PJM and NYISO flow based hours and price differences (Hudson): January through September, 2025

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	5,490	$28.69
	Consistent Flow (PJM to NYIS)	5,289	$29.18
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	201	$15.89
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	1,061	$22.32
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,002	$23.09
	No Flow	59	$9.22

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").[32] The PJM Out Service is covered by normal PJM OASIS business operations.[33] 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 1200 (EPT), one business day before the start of service. On September 30, 2025, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

32 See OASIS "PJM Business Practices for Hudson Transmission Service,"<https://www.pjm.com/-/media/DotCom/etools/oasis/merch-trans-facilities/hudson-oasis-business-practices-clean.pdf>.

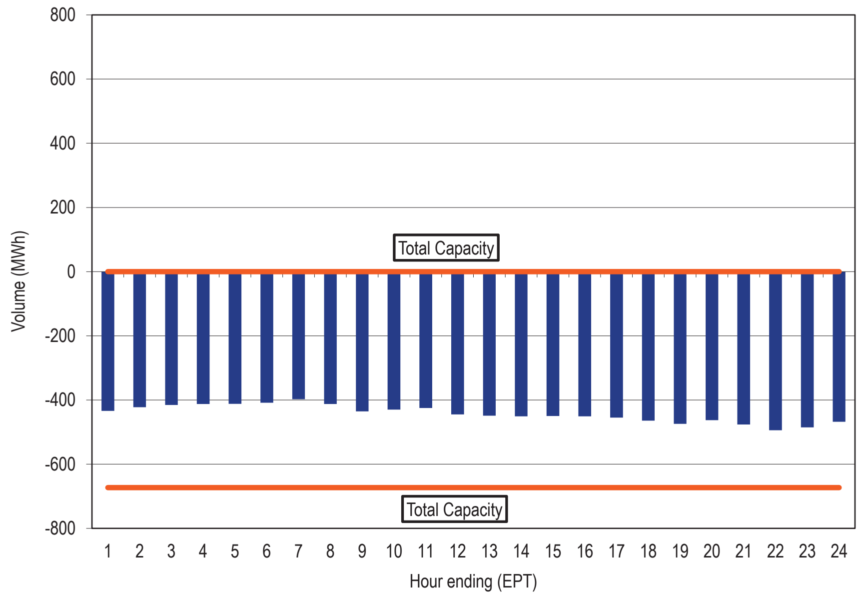
33 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 12 (July 26, 2023) <https://www.pjm.com/-/media/DotCom/etools/oasis/regional-practices-clean-pdf.pdf>.

Table 9-36 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-36 shows that in the first nine months of 2025, the primary rights holder was responsible for 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 nine months of 2025.

Table 9-36 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through September 2025[34]

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
January	NA	51.22%	16.27%	100.00%	NA	24.44%	52.21%	29.70%	37.64%	64.30%	81.40%	100.00%	100.00%
February	NA	49.00%	14.67%	NA	NA	23.25%	77.12%	23.61%	47.37%	64.34%	82.72%	100.00%	100.00%
March	NA	40.40%	71.88%	NA	NA	9.55%	72.42%	87.24%	53.27%	82.65%	83.41%	100.00%	100.00%
April	NA	100.00%	100.00%	NA	NA	15.13%	100.00%	10.02%	70.90%	84.91%	100.00%	100.00%	100.00%
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%	100.00%	20.53%	65.15%	84.15%	100.00%	100.00%	100.00%
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%	44.98%	38.26%	73.81%	100.00%	100.00%	100.00%	100.00%
July	100.00%	18.51%	84.34%	NA	NA	16.26%	36.43%	27.56%	76.56%	100.00%	89.66%	100.00%	100.00%
August	100.00%	75.17%	65.48%	NA	NA	19.24%	43.10%	35.64%	59.09%	100.00%	100.00%	80.35%	100.00%
September	100.00%	75.31%	78.73%	NA	NA	22.90%	43.42%	30.75%	53.66%	100.00%	100.00%	100.00%	100.00%
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%	33.60%	52.58%	56.26%	100.00%	100.00%	100.00%	
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	44.36%	38.60%	65.24%	68.68%	70.50%	100.00%	
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	41.78%	38.82%	61.11%	70.02%	83.43%	100.00%	

Figure 9-9 Hudson hourly average flow: January through September, 2025



34 The designation of "NA" means there was no flow on the Hudson Line during those months.

Interchange Activity During High Load Hours

The PJM metered system peak load during the first nine months of 2025 was 156,256 MW in the HE 1700 (EPT) on June 23, 2025. PJM was a net scheduled exporter of energy in all 24 hours on June 23, 2025, with average hourly scheduled exports of 3,360 MW. During HE 1700 on June 23, 2025, PJM had net scheduled exports of 2,296 MW and net metered actual exports of 2,158 MW. Net transaction exports during 1700 were consistent with price differences between the PJM/NEPT Interface and the NYIS/Neptune bus, the PJM/LIND Interface and the NYIS/Linden Bus and the PJM/HUDS Interface and the NYIS/Hudson Bus. Net transaction exports were inconsistent with price differences between PJM and MISO. Net transaction imports were consistent with price differences between PJM and the NYISO. During June 2025, PJM was a net scheduled exporter of energy in 718 of the 720 hours (99.7 percent of the hours). During June 2025, the average hourly scheduled interchange was -5,003 MW (representing 5.0 percent of the average hourly load of 99,752 MW in June 2025).

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, LG&E and KU; 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 9-37 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-37 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA-LGE-KU	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	NO	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-LGE-KU = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA), Louisville Gas and Electric Company (LGE) and Kentucky Utilities Company (KU)
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[35]

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 congestion management that, for designated flowgates within MISO and PJM, allows 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. This process was designed to address the impacts of market flows which are the loop flows on MISO's system created by PJM generators serving PJM load and vice versa. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[36]

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

35 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.
36 See "PJM/MISO Joint and Common Market Initiative," <https://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common>.

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.[37] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

Coordinated flowgates are identified to determine which flowgates the market flows from PJM or MISO affect significantly. This set of flowgates may then be used in the congestion management process. PJM and MISO will conduct sensitivity studies to determine which flowgates are significantly affected by the market flows of the operating entity's control zones (historic control areas that existed in the IDC). There are 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. PJM or MISO may also specify additional flowgates that have not passed any of the five studies to be coordinated flowgates where the operating entity expects to use the TLR process to manage congestion. 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.[38]

As of January 1, 2025, PJM had 208 flowgates eligible for M2M (Market to Market) coordination. In the first nine months of 2025, PJM added 16 flowgates and deleted 93 flowgates, resulting in 131 flowgates eligible for M2M coordination as of September 30, 2025. As of January 1, 2025, MISO had 222 flowgates eligible for M2M coordination. In the first nine months of 2025, MISO added 30 flowgates and deleted 62 flowgates, resulting in 190 flowgates eligible for M2M coordination as of September 30, 2025.

The firm flow entitlement (FFE) represents the amount of historic 2004 market flows 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 nonmonitoring RTO will pay the monitoring RTO the difference between their market flow and their FFE times the monitoring RTO's shadow price of the RCF. The shadow price is the incremental cost of dispatching marginal generation resources to relieve congestion on the RCF. If the nonmonitoring 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 nonmonitoring RTO. This payment is the difference between the nonmonitoring RTO's market flow and their FFE times the monitoring RTO's shadow price of the RCF.

April 1, 2004, known as the freeze date, is used to determine the firm rights on flowgates based on historic firm market flows that occurred prior to the implementation of M2M coordination. In the 21 years since 2004, significant topology and market changes have occurred, making the 2004 market flows irrelevant in 2025. The RTOs and stakeholders recognize that a modification to the definition of firm rights on flowgates is necessary. PJM and MISO stakeholders have spent years on the freeze date issues. No resolution to these issues appears imminent. The status quo results in significant payments by PJM customers to MISO customers. The final resolution should account for the investments made by each RTO in the transmission system. The final resolution should reflect current interchange patterns. In 2004, PJM was primarily an importer of energy from MISO. In 2025, as it has been since about 2010, PJM is primarily an exporter of energy to MISO.

The MMU recommends eliminating the mechanism that defines FFE and M2M payments. These mechanisms are not consistent with markets and are not needed for efficient interface pricing. PJM and MISO have demonstrated a longstanding failure to resolve the definition of firm rights on flowgates and related issues. The MMU recommends that PJM file with the Commission to eliminate the FFE calculation and M2M payment of the PJM and MISO joint operating agreement.

The original logic of FFEs was not clear, the calculation of FFEs was not clear, and the measurement of market flows was and is imprecise at best. It does not

37 See the *2012 Annual State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.
38 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

make sense to use outdated and meaningless FFEs from 2004. If current FFEs are used based on actual current power flows, the role of FFEs is not clear. Fully dynamic FFEs are equivalent to eliminating FFEs while continuing to price power flows at the correct shadow price.

The solution to the FFE and M2M issue is to eliminate FFEs. Elimination of FFEs, while maintaining the exchange of shadow price information and cooperative dispatch, would keep the benefits of efficient constraint resolution between PJM and MISO.

In the first nine months of 2025, 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. Table 9-38 shows credits for coordinated congestion management between PJM and MISO. In the first nine months of 2025, MISO payments to PJM were $7.6 million, and PJM payments to MISO were $63.8 million, for a net payment from PJM to MISO of $56.2 million. The large settlements in 2022 were due to the large amount of congestion and high LMPs observed in December during Winter Storm Elliott.

Table 9-38 PJM/MISO credits for coordinated congestion management: April 2005 through September 2025[39]

Year	Payments from PJM to MISO	Payments from MISO to PJM	Net Payment from PJM to MISO
2005	$25,068,903	$3,411,188	$21,657,715
2006	$18,664,630	$21,381,460	($2,716,830)
2007	$29,917,241	$17,774,637	$12,142,604
2008	$60,615,478	$15,417,040	$45,198,438
2009	$48,101,017	$10,632,885	$37,468,132
2010	$56,330,068	$20,558,982	$35,771,087
2011	$87,113,498	$9,445,949	$77,667,550
2012	$56,227,681	$7,602,112	$48,625,569
2013	$32,589,519	$14,733,770	$17,855,748
2014	$62,572,610	$19,263,896	$43,308,713
2015	$49,379,823	$11,266,866	$38,112,957
2016	$50,628,816	$9,826,347	$40,802,469
2017	$69,812,858	$16,698,276	$53,114,581
2018	$110,501,078	$10,400,122	$100,100,956
2019	$44,391,547	$7,886,392	$36,505,155
2020	$53,038,595	$7,985,027	$45,053,568
2021	$45,704,128	$18,792,183	$26,911,945
2022	$191,716,652	$8,560,992	$183,155,660
2023	$63,976,499	$5,467,435	$58,509,064
2024	$58,627,460	$17,671,566	$40,955,894
2025 (Jan)	$16,303,017	$0	$16,303,017
2025 (Feb)	$7,040,650	$272,322	$6,768,328
2025 (Mar)	$11,328,210	$149,429	$11,178,782
2025 (Apr)	$12,140,633	$385,758	$11,754,874
2025 (May)	$4,122,837	$69,789	$4,053,049
2025 (Jun)	$3,117,356	$2,614,125	$503,231
2025 (Jul)	$2,314,333	$1,332,336	$981,997
2025 (Aug)	$1,036,764	$2,428,997	($1,392,233)
2025 (Sep)	$6,406,708	$369,613	$6,037,094
2025	$63,810,508	$7,622,368	$56,188,140

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

PJM and New York Independent System Operator Joint Operating Agreement (JOA)[40]

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. Unlike the PJM/MISO JOA where firm flow entitlements are based on a freeze date, the PJM/NYISO JOA requires that each party calculates an M2M entitlement on each M2M flowgate and compare results at least once a year. This annual coordination of entitlements ensures that the impact of upgrades on both systems are incorporated into the M2M calculation. PJM and NYISO may mutually agree to not recalculate entitlements in a given year.

On June 28, 2019, NYISO and PJM submitted revisions to the NYISO-PJM Joint Operating Agreement (JOA). The revisions addressed RTO concerns identified in their joint request for limited waiver of the JOA to authorize redispatch of generation in PJM. The intent of the redispatch is to mitigate post-contingency overloads of transmission equipment on the New York side of the East Towanda-Hillside 230 kV Transmission Line. The agreement allows the RTOs to control for this contingency without the exchange of payments for redispatch.[41]

In the first nine months of 2025, 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 nine months of 2025. Table 9-39 shows credits for coordinated congestion management between PJM and NYISO.

Table 9-39 PJM/NYISO credits for coordinated congestion management (flowgates): January 2013 through September 2025[42]

Year	Payments from PJM to NYISO	Payments from NYISO to PJM	Net Payment from PJM to NYISO
2013	$119,121	$0	$119,121
2014	$58,631	$1,005	$57,626
2015	$242,488	$5,063	$237,425
2016	$632,768	$50,550	$582,219
2017	$422,304	$895	$421,409
2018	$0	$0	$0
2019	$0	$0	$0
2020	$0	$0	$0
2021	$0	$0	$0
2022	$0	$0	$0
2023	$0	$0	$0
2024	$0	$0	$0
2025 (Jan)	$0	$0	$0
2025 (Feb)	$0	$0	$0
2025 (Mar)	$0	$0	$0
2025 (Apr)	$0	$0	$0
2025 (May)	$0	$0	$0
2025 (Jun)	$0	$0	$0
2025 (Jul)	$0	$0	$0
2025 (Aug)	$0	$0	$0
2025 (Sep)	$0	$0	$0
2025	$0	$0	$0

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 affect both markets, focusing on the actual flows in real time to manage constraints.[43] 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.

40 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <https://www.pjm.com/~/media/DotCom/documents/agreements/nyiso-joa.ashx>.

41 See NYISO Filing, FERC Docket No. ER19-2282-000 (June 28, 2019).

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

43 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <https://www.pjm.com/~/media/DotCom/documents/agreements/nyiso-joa.ashx>.

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 nine months of 2025, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. In the first nine months of 2025, PJM payments to NYISO were $2.6 million, and NYISO payments to PJM were $3.2 million, for a net payment from NYISO to PJM of $565,570. Table 9-40 shows the PAR credits for coordinated congestion management between PJM and NYISO.

Table 9-40 PJM/NYISO credits for coordinated congestion management (PARs): January 2013 through September 2025[44]

Year	Payments from PJM to NYISO	Payments from NYISO to PJM	Net Payment from PJM to NYISO
2013	$7,403,255	$0	$7,403,255
2014	$5,723,571	$0	$5,723,571
2015	$4,691,302	$0	$4,691,302
2016	$617,733	$0	$617,733
2017	$2,328,763	$2,115,126	$213,637
2018	$3,327,747	$2,407,667	$920,081
2019	$3,341,615	$2,923,715	$417,900
2020	$3,004,543	$2,048,317	$956,226
2021	$8,911,160	$6,751,890	$2,159,270
2022	$21,128,605	$13,611,434	$7,517,171
2023	$1,755,207	$2,208,388	($453,181)
2024	$376,435	$1,227,033	($850,597)
2025 (Jan)	$1,057,106	$1,751,095	($693,989)
2025 (Feb)	$193,284	$427,199	($233,915)
2025 (Mar)	$178,336	$339,994	($161,657)
2025 (Apr)	$2,290	$1,203	$1,087
2025 (May)	$3,690	$985	$2,705
2025 (Jun)	$656,570	$344,867	$311,702
2025 (Jul)	$543,293	$149,277	$394,016
2025 (Aug)	$12,092	$148,239	($136,148)
2025 (Sep)	$28,036	$77,407	($49,371)
2025	$2,674,697	$3,240,267	($565,570)

44 The totals in this figure are from the settlements at the time of this report and may change based on later adjustments or resettlements.

PJM and TVA/LG&E and KU Joint Reliability Coordination Agreement (JRCA)[45]

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. In 2022, PJM and TVA began discussions to add Louisville Gas and Electric Company (LG&E) and Kentucky Utilities (KU) as parties to the JRCA. The revisions to add LG&E and KU to the agreement were filed with the Commission on June 6, 2023.[46] On August 5, 2023, the Commission approved the filing.[47] The agreement remained in effect in the first nine months of 2025.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[48]

On September 9, 2005, 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 include a CMP under Article 14 of the JOA.[49] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy

45 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," (October 15, 2014) <https://www.pjm.com/library/governing-documents>.
46 See *PJM Interconnection, L.L.C*, Docket No. ER23-2078-000 (June 6, 2023).
47 See *PJM Interconnection, L.L.C*, Docket No. ER23-2078-000 (August 5, 2023).
48 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (July 22, 2019) <https://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>.
49 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

Carolinas Inc., now a subsidiary of Duke Energy, changed its name to Duke Energy Progress (DEP).

On May 20, 2019, PJM and DEP submitted revisions to the JOA to delete Article 14.[50] PJM and DEP requested an effective date of July 22, 2019, for the filed revisions. On July 2, 2019, the Commission issued a letter order accepting the revisions to the JOA to delete the congestion management agreement effective July 22, 2019.[51]

PJM and VACAR South Reliability Coordination Agreement[52]

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. (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 nine months of 2025.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[53]

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 nine months of 2025.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[54]

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 nine months of 2025.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, loop flows for example, 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 zero in the first nine months of 2024 to two in the first nine months of 2025. The number of different flowgates for which PJM declared a TLR 3a was zero in the first nine months of 2024, and two in the first nine months of 2025. The total MWh of transaction curtailments was zero in the first nine months of 2024, and 5,646 MWh in the first nine months of 2025.[55]

The number of MISO issued TLRs of level 3a or higher increased from 17 in the first nine months of 2024 to 22 in the first nine months of 2025. The number of different flowgates for which MISO declared a TLR 3a was 13 in the first nine months of 2024, and 12 in the first nine months of 2025. The total MWh of transaction curtailments decreased by 4.5 percent from 13,048 MWh in the first nine months of 2024 to 12,462 MWh in the first nine months of 2025.

50 See *PJM Interconnection, L.L.C*, Docket No. ER19-1905-000 (May 20, 2019).
51 FERC Docket No. ER19-1905-000.
52 See "PJM-VACAR South RC Agreement," (November 7, 2014) <https://www.pjm.com/-/media/DotCom/documents/agreements/executed-pjm-vacar-rc-agreement.pdf>.
53 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, L.L.C.," (July 20, 2013) <https://www.pjm.com/directory/merged-tariffs/rs43.pdf>.
54 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <https://www.pjm.com/-/media/DotCom/documents/agreements/NE_Protocol.ashx>.
55 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2020 Annual State of the Market Report for PJM*, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

The number of NYISO issued TLRs of level 3a or higher decreased from two in the first nine months of 2024 to zero in the first nine months of 2025. The number of different flowgates for which NYISO declared a TLR 3a or higher was one in the first nine months of 2024, and zero in the first nine months of 2025. The total MWh of transaction curtailments was from 11,597 MWh in the first nine months of 2024, and zero MWh in the first nine months of 2025.

Table 9-41 PJM, MISO, and NYISO TLR procedures: January through September, 2025[56]

	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-25	2	2	0	2	2	0	5,646	5,266	0
Feb-25	0	0	0	0	0	0	0	0	0
Mar-25	0	1	0	0	1	0	0	120	0
Apr-25	0	6	0	0	2	0	0	5,568	0
May-25	0	3	0	0	2	0	0	421	0
Jun-25	0	0	0	0	0	0	0	0	0
Jul-25	0	2	0	0	2	0	0	0	0
Aug-25	0	2	0	0	1	0	0	175	0
Sep-25	0	6	0	0	4	0	0	912	0
Total	2	22	0	2	12	0	5,646	12,462	0

Table 9-42 Number of TLRs by TLR level by reliability coordinator: January through September, 2025[57]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2025	MISO	9	3	0	3	7	0	22
	NYIS	0	0	0	0	0	0	0
	ONT	1	0	0	0	0	0	1
	PJM	0	2	0	0	0	0	2
	SOCO	58	89	0	0	0	0	147
	SWPP	84	136	0	10	14	0	244
	TVA	31	26	0	5	5	0	67
	VACS	2	8	0	0	0	0	10
Total		185	264	0	18	26	0	493

Up To Congestion Transactions

The original purpose, in 2000, 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.[58]

Up to congestion transactions affect the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions were not required to pay uplift charges from their introduction in 2000 through October 31, 2020. On July 16, 2020, FERC issued an Order directing PJM to revise uplift allocation rules to allocate uplift to one side of up to congestion transactions.[59] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. Up to congestion transactions also negatively affect FTR funding.[60]

Figure 9-10 shows the monthly volume of cleared up to congestion transactions. Following an initial decline, UTC volumes had steadily increased following the allocation of uplift charges to UTCs effective November 1, 2020. However, the volume of cleared UTC transactions has declined again in the recent 12 month period to levels below what was seen prior to the allocation of uplift charges to UTCs. Table 9-43 shows the UTC volumes from the 12 month period prior to the allocation of uplift charges (November 1, 2019, through October 31, 2020), to the most recent 12 month period (October 1, 2024 through September 30, 2025). Table 9-44 shows the UTC volumes for the first nine months of 2024 and 2025.

56 The total row in the columns of the number of unique flowgates that experience TLRs are not a sum of the individual months. The total row represents the number of unique flowgates that have experienced TLRs for the year to date.

57 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.

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

59 172 FERC ¶ 61,046 (2020).

60 See the *2025 Quarterly State of the Market Report for PJM: January through September*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

Figure 9-10 Monthly up to congestion cleared bids in MWh: January 2005 through September 2025

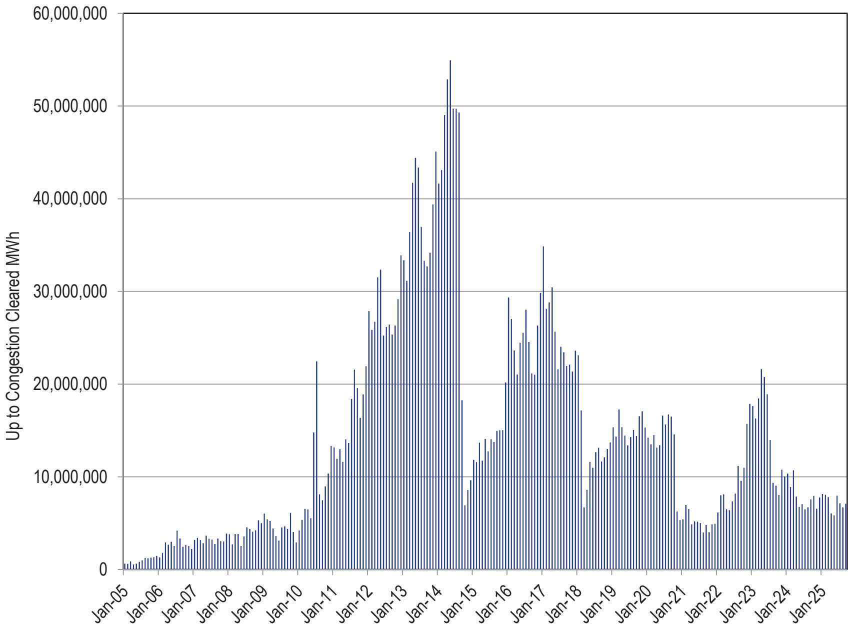


Table 9-43 Up to congestion volumes: November 1, 2019 through October 31, 2020 compared to October 1, 2024 through September 30, 2025

Category	November 1, 2019 - October 31, 2020	October 1, 2024 - September 30, 2025	Percent Change
Daily Average UTC Bids Submitted	53,368	46,408	(13.0%)
Daily Average UTC Bids Cleared	26,415	17,251	(34.7%)
Daily Average UTC Volume Submitted (MWh)	1,279,124	744,973	(41.8%)
Daily Average UTC Volume Cleared (MWh)	495,001	238,600	(51.8%)

Table 9-44 Up to congestion volumes: January through September, 2024 and 2025

Category	2024 (Jan-Sep)	2025 (Jan-Sep)	Percent Change
Daily Average UTC Bids Submitted	36,083	48,979	35.7%
Daily Average UTC Bids Cleared	16,374	17,795	8.7%
Daily Average UTC Volume Submitted (MWh)	747,595	737,144	(1.4%)
Daily Average UTC Volume Cleared (MWh)	264,091	237,417	(10.1%)

Table 9-45 shows the monthly cleared submitted volume of UTC bids from January 2024 through September 2025. In the first nine months of 2025, the cleared MW volume of up to congestion transactions was comprised of 7.6 percent imports, 5.8 percent exports, 1.6 percent wheeling transactions and 85.0 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

Table 9-45 Monthly volume of cleared and submitted up to congestion bids: January 2024 through September, 2025

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-24	1,393,908	3,446,217	622,629	20,738,830	26,201,585	109,639	177,019	28,013	925,575	1,240,246
Feb-24	1,276,448	3,487,721	557,922	15,563,296	20,885,387	85,438	162,871	19,625	641,688	909,622
Mar-24	2,114,589	3,095,560	615,033	22,158,786	27,983,969	104,029	137,178	15,664	806,929	1,063,800
Apr-24	2,553,802	880,919	631,655	21,263,080	25,329,456	132,464	57,815	12,169	836,727	1,039,175
May-24	1,770,205	1,086,810	351,244	19,034,294	22,242,552	112,625	64,120	11,640	977,182	1,165,567
Jun-24	1,623,412	1,186,571	207,398	15,883,613	18,900,994	82,777	64,774	8,241	826,865	982,657
Jul-24	1,382,861	1,410,922	228,738	17,081,886	20,104,409	88,958	74,617	8,613	967,827	1,140,015
Aug-24	1,745,713	1,889,045	395,980	16,778,581	20,809,318	113,673	84,362	11,550	962,180	1,171,765
Sep-24	1,919,983	2,052,034	378,662	18,032,721	22,383,400	108,782	95,667	13,048	956,495	1,173,992
Oct-24	2,506,298	1,888,422	299,715	20,096,647	24,791,083	131,812	96,221	11,494	959,073	1,198,600
Nov-24	1,630,883	1,941,307	369,918	17,782,010	21,724,119	96,476	102,770	12,427	825,449	1,037,122
Dec-24	2,915,183	2,366,307	412,163	18,466,015	24,159,668	159,107	140,388	18,745	1,013,390	1,331,630
Jan-25	2,205,672	2,182,123	334,327	21,101,450	25,823,572	125,604	187,964	18,092	1,300,404	1,632,064
Feb-25	2,455,996	2,513,637	359,618	18,056,777	23,386,028	114,520	183,212	32,050	1,036,986	1,366,768
Mar-25	3,118,908	1,826,595	278,735	20,664,128	25,888,366	170,467	150,970	20,393	1,214,563	1,556,393
Apr-25	2,179,369	789,354	341,206	17,872,615	21,182,544	169,667	95,947	17,035	1,156,357	1,439,006
May-25	1,300,945	867,919	224,558	13,954,428	16,347,850	105,869	85,547	12,625	966,859	1,170,900
Jun-25	1,814,662	1,402,459	171,331	19,928,093	23,316,546	144,615	104,586	12,351	1,229,721	1,491,273
Jul-25	2,271,084	1,445,784	259,642	17,998,508	21,975,019	186,792	125,712	18,569	1,327,626	1,658,699
Aug-25	2,006,277	1,591,872	280,230	15,399,345	19,277,724	146,474	122,446	18,102	1,053,784	1,340,806
Sep-25	1,417,219	2,117,739	234,451	20,273,139	24,042,548	154,729	134,822	15,782	1,410,148	1,715,481
TOTAL	41,603,415	39,469,320	7,555,158	388,128,243	476,756,136	2,644,517	2,449,008	336,228	21,395,828	26,825,581

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-24	432,931	1,174,081	249,337	8,489,035	10,345,385	50,907	74,004	11,400	448,898	585,209
Feb-24	490,568	986,528	245,479	7,167,365	8,889,940	34,100	54,648	6,789	296,101	391,638
Mar-24	688,499	964,650	274,492	8,772,338	10,699,978	37,226	54,211	5,702	348,530	445,669
Apr-24	575,102	319,891	253,730	6,714,925	7,863,648	37,781	23,217	4,342	320,186	385,526
May-24	391,409	375,117	168,607	5,815,471	6,750,604	36,393	27,920	3,660	398,792	466,765
Jun-24	488,592	476,316	71,640	6,026,374	7,062,923	35,413	30,970	3,012	390,313	459,708
Jul-24	352,243	455,325	79,374	5,601,800	6,488,742	37,627	30,095	1,938	493,552	563,212
Aug-24	563,725	410,942	143,077	5,590,248	6,707,992	56,263	24,647	4,618	540,450	625,978
Sep-24	634,070	507,312	139,039	6,271,395	7,551,817	41,991	31,418	5,009	484,376	562,794
Oct-24	734,933	526,973	96,888	6,589,942	7,948,736	43,705	33,318	3,706	417,490	498,219
Nov-24	418,179	528,677	152,846	5,456,604	6,556,306	33,395	31,180	4,160	315,374	384,109
Dec-24	945,870	509,356	178,429	6,135,454	7,769,108	69,597	43,388	8,311	435,152	556,448
Jan-25	464,114	701,211	108,021	6,876,908	8,150,254	32,413	91,771	6,004	547,475	677,663
Feb-25	748,465	537,412	144,845	6,633,542	8,064,264	41,822	54,750	11,534	428,231	536,337
Mar-25	678,923	587,700	152,636	6,391,031	7,810,290	46,728	57,345	7,116	439,419	550,608
Apr-25	397,841	217,089	149,400	5,294,497	6,058,826	35,760	26,334	4,065	373,011	439,170
May-25	363,478	312,867	120,464	5,044,292	5,841,101	24,841	20,884	3,267	324,995	373,987
Jun-25	590,128	292,998	81,725	6,988,373	7,953,223	56,190	26,403	3,754	483,442	569,789
Jul-25	678,823	266,906	74,374	6,118,292	7,138,395	79,167	25,831	5,399	568,717	679,114
Aug-25	702,076	328,270	99,923	5,580,230	6,710,499	55,827	27,995	5,273	408,458	497,553
Sep-25	328,860	509,245	75,506	6,174,356	7,087,967	39,739	30,513	3,961	459,532	533,745
TOTAL	11,668,827	10,988,867	3,059,833	133,732,471	159,449,997	926,885	820,842	113,020	8,922,494	10,783,241

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.

At the April 10, 2013, PJM Market Implementation Committee (MIC), the MMU presented a problem statement and issue charge to address sham scheduling activities.[61] The expected deliverables from the stakeholder meetings were revisions to the Tariff and PJM business manuals. The topic was discussed at several MIC meetings. While there was stakeholder agreement that sham scheduling activity was inappropriate, consensus on revised tariff and manual language was not achieved. The topic was closed. The MMU clarified that it would continue to monitor transactions for sham scheduling activities and that the MMU could refer market participants for sham scheduling activities.

The MMU monitors for sham scheduling activities on a daily basis. Following the stakeholder discussions in 2013, the net profits obtained from sham scheduling activities fell by 104.9 percent, from net profits of $15.5 million in 2014, to a net loss of $761,012 in 2024. The total number of hours of sham scheduling segments where the MW profile matched exactly across all segments of the path combinations in the same hour fell by 86.6 percent, from 1,898 hours in 2014 to 254 hours in 2024.

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

61 *See* Market Path/Interface Pricing Point alignment Problem Statement, at: <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Market_Path_Interface_Pricing_Point_Alignment_Problem_Statement_201304010.pdf>.

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.[62] 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.

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 nine months of 2025, there were 666.5 GWh of net scheduled transactions between PJM and IESO. The net scheduled transactions were made up of 676.5 GWh of imports wheeled through MISO, and 10.0 GWh of exports wheeled through the NYISO. (Table 9-25). The MMU recommends

62 *See* "Sham Scheduling," Presented at the PJM Market Monitoring Unit Advisory Committee (MMUAC) meeting held on December 6, 2013 <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_Sham_Scheduling_20131206.pdf>.

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.[63]

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.[64] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price IT SCED 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.

The IT SCED application runs 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 IT SCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first nine months of 2025. Table 9-46 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 22.5 percent of the intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $2.22 per MWh. In 26.3 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $94.53 when the price difference was greater than $20.00, and $67.32 when the price difference was greater than -$20.00.

63 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.
64 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

Table 9-46 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2025

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	18.4%	$94.53
$10 to $20	10.3%	$14.29
$5 to $10	11.3%	$7.22
$0 to $5	22.5%	$2.22
$0 to -$5	17.4%	$2.04
-$5 to -$10	6.4%	$7.18
-$10 to -$20	5.7%	$14.33
< -$20	7.9%	$67.32

Table 9-47 shows how the accuracy of the IT SCED forecasted LMPs changes as the cases approach real-time. In the final IT SCED results prior to real time, in 35.5 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 39.5 percent in the 135 minute ahead IT SCED results.

Table 9-47 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2025

	~ 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	23.2%	$99.14	15.6%	$77.12	17.8%	$90.62	20.1%	$106.99
$10 to $20	10.6%	$14.39	10.4%	$14.25	9.9%	$14.23	10.2%	$14.36
$5 to $10	11.1%	$7.24	11.5%	$7.23	11.5%	$7.21	10.2%	$7.26
$0 to $5	23.2%	$2.18	24.4%	$2.21	21.6%	$2.25	17.9%	$2.24
$0 to -$5	16.3%	$1.91	18.1%	$2.01	17.4%	$2.09	17.6%	$2.21
-$5 to -$10	5.1%	$7.08	6.3%	$7.23	6.9%	$7.14	7.7%	$7.16
-$10 to -$20	4.4%	$14.47	5.6%	$14.37	6.3%	$14.27	6.9%	$14.25
< -$20	6.1%	$70.36	8.0%	$66.57	8.6%	$68.01	9.4%	$64.41

In 29.5 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price difference was $106.99 when the price difference was greater than $20.00, and $64.41 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/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-48 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): January through September, 2025

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	19.1%	24.6%	18.8%	21.8%	14.2%	20.2%	32.8%	15.6%	13.8%	20.1%
	$10 to $20	9.2%	8.4%	9.7%	14.7%	10.2%	9.5%	9.3%	9.2%	12.0%	10.2%
	$5 to $10	11.1%	8.5%	12.4%	13.3%	11.1%	10.1%	5.8%	9.8%	9.2%	10.2%
	$0 to $5	17.2%	12.7%	18.7%	22.7%	25.7%	16.2%	13.3%	17.1%	17.4%	17.9%
	$0 to -$5	15.7%	13.2%	16.5%	14.5%	24.6%	16.4%	14.7%	23.0%	19.2%	17.6%
	-$5 to -$10	6.7%	7.8%	7.6%	4.7%	7.3%	8.3%	7.6%	9.6%	9.6%	7.7%
	-$10 to -$20	7.6%	9.1%	7.4%	3.7%	3.4%	7.9%	6.8%	8.1%	8.7%	6.9%
	< -$20	13.4%	15.9%	9.0%	4.7%	3.5%	11.3%	9.8%	7.5%	10.1%	9.4%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	19.1%	25.0%	17.9%	23.4%	10.6%	17.5%	26.1%	11.5%	10.3%	17.8%
	$10 to $20	10.4%	8.6%	9.7%	12.0%	9.6%	10.2%	10.6%	8.9%	9.3%	9.9%
	$5 to $10	12.0%	9.4%	12.6%	14.6%	12.7%	11.5%	7.9%	11.4%	11.2%	11.5%
	$0 to $5	20.0%	14.5%	20.4%	24.0%	31.2%	20.4%	16.9%	23.5%	22.8%	21.6%
	$0 to -$5	14.6%	12.7%	16.3%	14.2%	23.6%	17.3%	15.9%	22.1%	19.5%	17.4%
	-$5 to -$10	6.6%	7.7%	7.5%	4.2%	5.9%	7.4%	6.6%	7.7%	8.8%	6.9%
	-$10 to -$20	6.7%	8.3%	7.1%	3.3%	3.1%	5.9%	6.8%	7.5%	7.9%	6.3%
	< -$20	10.6%	13.7%	8.6%	4.4%	3.5%	9.9%	9.2%	7.4%	10.2%	8.6%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	16.0%	21.3%	13.5%	15.4%	7.9%	17.4%	26.5%	11.8%	11.2%	15.6%
	$10 to $20	10.3%	10.1%	10.1%	11.1%	8.6%	11.5%	11.4%	10.1%	10.2%	10.4%
	$5 to $10	12.2%	9.1%	11.6%	13.9%	13.2%	11.2%	9.5%	11.2%	11.4%	11.5%
	$0 to $5	24.0%	16.2%	24.0%	28.3%	33.9%	22.5%	19.7%	24.9%	25.2%	24.4%
	$0 to -$5	15.1%	14.4%	17.4%	18.1%	24.3%	17.1%	15.0%	22.7%	18.7%	18.1%
	-$5 to -$10	5.9%	8.1%	8.1%	4.0%	5.4%	6.1%	4.8%	7.4%	7.4%	6.3%
	-$10 to -$20	5.5%	7.8%	6.4%	4.3%	3.3%	5.6%	4.9%	5.8%	7.2%	5.6%
	< -$20	11.0%	13.0%	8.9%	5.0%	3.3%	8.5%	8.1%	6.1%	8.6%	8.0%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	21.8%	30.0%	24.0%	21.0%	16.5%	22.1%	34.3%	18.5%	20.8%	23.2%
	$10 to $20	10.8%	7.8%	10.9%	11.4%	10.1%	11.3%	11.7%	10.2%	10.7%	10.6%
	$5 to $10	10.6%	9.0%	11.1%	12.4%	13.3%	11.1%	9.4%	11.4%	11.3%	11.1%
	$0 to $5	23.0%	14.5%	21.0%	27.9%	30.6%	23.8%	19.3%	25.1%	22.9%	23.2%
	$0 to -$5	14.5%	14.5%	16.3%	16.9%	20.9%	15.6%	11.8%	19.3%	16.6%	16.3%
	-$5 to -$10	5.2%	7.2%	6.0%	4.0%	3.8%	4.8%	3.5%	5.7%	5.9%	5.1%
	-$10 to -$20	5.0%	6.2%	4.2%	3.2%	2.6%	4.3%	4.2%	5.2%	5.3%	4.4%
	< -$20	9.1%	10.8%	6.5%	3.3%	2.3%	6.8%	5.8%	4.5%	6.6%	6.1%

Table 9-49 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January through September, 2025

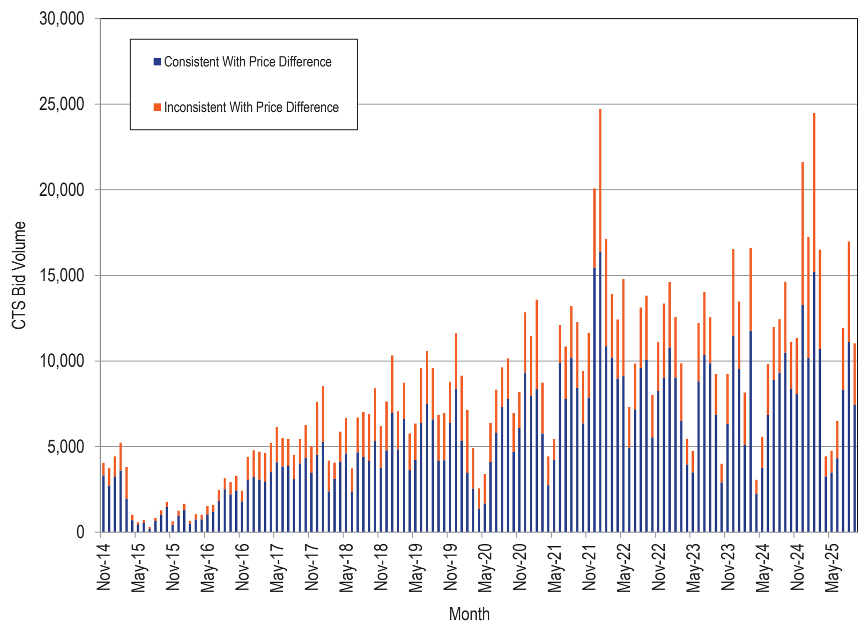
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$66.91	$73.56	$57.65	$47.28	$37.02	$257.61	$203.85	$72.90	$39.03	$106.99
	$10 to $20	$14.16	$14.45	$14.37	$14.30	$13.95	$14.48	$15.10	$14.13	$14.41	$14.36
	$5 to $10	$7.10	$7.50	$7.16	$7.32	$7.20	$7.28	$7.29	$7.13	$7.48	$7.26
	$0 to $5	$2.39	$2.29	$2.36	$2.30	$2.15	$2.21	$2.15	$2.03	$2.27	$2.24
	$0 to -$5	$2.16	$2.32	$2.29	$2.07	$2.14	$2.10	$2.37	$2.17	$2.33	$2.21
	-$5 to -$10	$7.13	$7.19	$7.14	$7.23	$6.94	$7.39	$7.27	$7.19	$7.03	$7.16
	-$10 to -$20	$14.22	$14.14	$14.40	$13.86	$14.05	$14.29	$14.37	$14.43	$14.19	$14.25
	< -$20	$66.18	$50.37	$71.55	$75.27	$68.96	$92.87	$51.02	$51.97	$60.65	$64.41
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$56.99	$73.95	$65.32	$55.25	$43.32	$205.16	$151.34	$66.71	$41.61	$90.62
	$10 to $20	$14.20	$14.46	$13.96	$14.11	$14.06	$14.40	$14.59	$14.11	$14.20	$14.23
	$5 to $10	$7.28	$7.25	$7.16	$7.20	$7.09	$7.24	$7.23	$7.19	$7.35	$7.21
	$0 to $5	$2.45	$2.36	$2.34	$2.30	$2.19	$2.30	$2.04	$2.12	$2.24	$2.25
	$0 to -$5	$2.20	$2.22	$2.22	$1.87	$2.00	$2.07	$2.18	$1.90	$2.23	$2.09
	-$5 to -$10	$7.18	$7.19	$7.18	$7.02	$7.13	$7.12	$7.22	$7.15	$7.02	$7.14
	-$10 to -$20	$14.23	$14.71	$14.48	$13.93	$14.15	$14.14	$14.15	$14.06	$14.28	$14.27
	< -$20	$69.97	$52.43	$71.80	$75.76	$69.31	$106.08	$57.08	$55.11	$61.32	$68.01
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$51.98	$54.21	$48.84	$43.51	$40.30	$169.07	$108.96	$74.13	$45.78	$77.12
	$10 to $20	$14.45	$14.10	$13.74	$14.52	$13.69	$14.44	$14.56	$14.36	$14.20	$14.25
	$5 to $10	$7.23	$7.40	$7.12	$7.19	$7.16	$7.30	$7.35	$7.14	$7.31	$7.23
	$0 to $5	$2.39	$2.33	$2.26	$2.20	$2.14	$2.16	$2.19	$2.09	$2.20	$2.21
	$0 to -$5	$2.12	$2.22	$2.06	$1.94	$1.93	$2.04	$2.01	$1.87	$2.10	$2.01
	-$5 to -$10	$7.06	$7.37	$7.21	$7.12	$7.06	$7.49	$7.12	$7.40	$7.13	$7.23
	-$10 to -$20	$14.32	$14.29	$14.53	$14.14	$14.45	$14.16	$14.75	$14.27	$14.42	$14.37
	< -$20	$71.43	$50.57	$72.52	$72.23	$70.10	$89.99	$56.46	$58.33	$64.48	$66.57
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$99.65	$102.31	$100.22	$81.31	$86.93	$155.81	$101.53	$83.00	$71.44	$99.14
	$10 to $20	$14.34	$14.32	$14.26	$14.37	$14.19	$14.54	$14.54	$14.25	$14.65	$14.39
	$5 to $10	$7.20	$7.27	$7.22	$7.12	$7.25	$7.33	$7.34	$7.31	$7.13	$7.24
	$0 to $5	$2.26	$2.22	$2.25	$2.15	$2.27	$2.07	$2.17	$1.98	$2.22	$2.18
	$0 to -$5	$1.88	$2.13	$2.05	$1.86	$1.73	$1.80	$1.97	$1.83	$2.06	$1.91
	-$5 to -$10	$7.11	$7.26	$7.13	$7.06	$7.00	$6.85	$7.08	$7.08	$7.09	$7.08
	-$10 to -$20	$14.39	$14.41	$14.17	$14.15	$14.17	$14.47	$14.84	$14.59	$14.77	$14.47
	< -$20	$68.63	$50.04	$76.38	$89.39	$79.96	$101.33	$60.50	$62.17	$67.38	$70.36

The NYISO uses PJM's IT SCED 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 IT SCED 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 September 30, 2025, 1,060,261 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 330,293 (31.2 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 31.2 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 68.8 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-11 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-11 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-11 Monthly cleared PJM/NYIS CTS bid volume: November 4, 2014 through September 30, 2025



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. This limits 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 (IT SCED). 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.

The IT SCED application runs 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 IT SCED solutions will produce 12 forecasted PJM/MISO interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first nine months of 2025. Table 9-50 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 23.2 percent of all intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $2.16. In 27.4 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $90.19 when the price difference was greater than $20.00, and $76.35 when the price difference was greater than -$20.00.

Table 9-50 Differences between forecast and actual PJM/MISO interface prices: January through September, 2025

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	22.3%	$90.19
$10 to $20	10.1%	$14.27
$5 to $10	10.9%	$7.22
$0 to $5	23.2%	$2.16
$0 to -$5	18.6%	$1.96
-$5 to -$10	5.7%	$7.09
-$10 to -$20	4.0%	$14.08
< -$20	5.1%	$76.35

Table 9-51 shows how the accuracy of the IT SCED forecasted LMPs change as the cases approach real-time. In the final IT SCED results prior to real-time, in 38.4 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 41.3 percent in the 135 minute ahead IT SCED results.

Table 9-51 Differences between forecast and actual PJM/MISO interface prices: January through September, 2025

	~ 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	25.7%	$98.11	20.1%	$76.49	21.3%	$86.57	24.9%	$101.29
$10 to $20	10.5%	$14.18	10.2%	$14.28	10.0%	$14.24	9.1%	$14.34
$5 to $10	11.0%	$7.20	11.4%	$7.21	11.0%	$7.23	9.4%	$7.23
$0 to $5	24.4%	$2.15	24.9%	$2.13	22.5%	$2.18	18.3%	$2.20
$0 to -$5	16.9%	$1.84	19.0%	$1.88	19.4%	$1.97	20.1%	$2.13
-$5 to -$10	4.6%	$7.11	5.6%	$7.11	6.2%	$7.10	7.3%	$7.07
-$10 to -$20	2.9%	$14.14	3.8%	$14.22	4.3%	$14.11	5.1%	$14.01
< -$20	3.9%	$82.85	5.0%	$76.54	5.4%	$77.01	5.8%	$72.45

In 30.7 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $101.29 when the price difference was greater than $20.00, and $72.45 when the price difference was greater than -$20.00.

Table 9-52 and Table 9-53 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 IT SCED forecast during periods of cold and hot weather.

Table 9-52 Monthly differences between forecast and actual PJM/MISO interface prices (percent of intervals): January through September, 2025

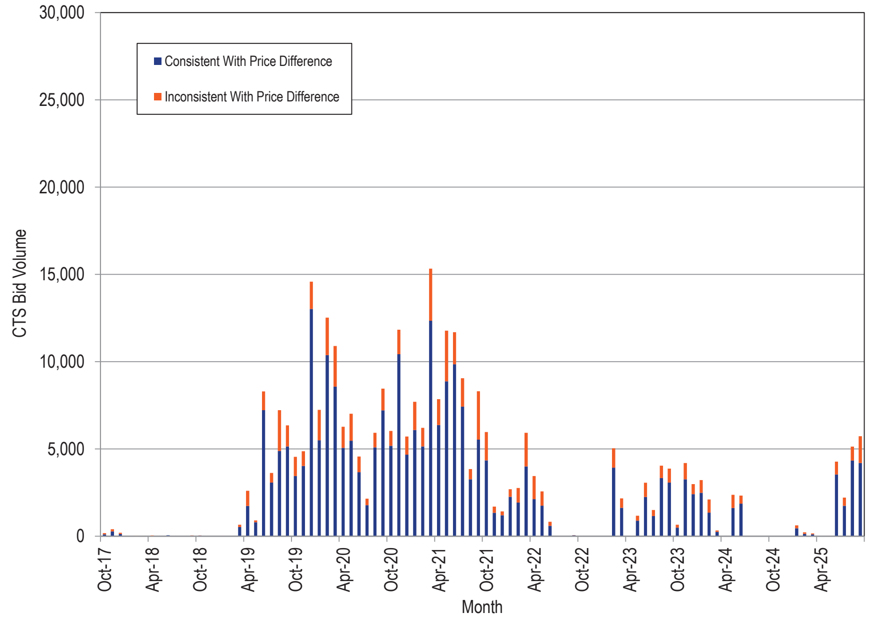
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	21.8%	21.6%	24.7%	33.9%	20.0%	25.9%	34.1%	20.0%	22.1%	24.9%
	$10 to $20	11.2%	8.6%	11.5%	12.5%	9.1%	6.8%	7.9%	7.4%	7.1%	9.1%
	$5 to $10	10.0%	13.1%	11.1%	10.0%	10.8%	7.9%	5.5%	7.9%	8.2%	9.4%
	$0 to $5	19.5%	18.6%	15.9%	13.9%	22.0%	19.6%	15.9%	20.5%	18.5%	18.3%
	$0 to -$5	17.6%	17.3%	14.3%	12.0%	24.0%	21.6%	22.1%	29.3%	22.3%	20.1%
	-$5 to -$10	6.4%	8.5%	8.0%	5.4%	6.7%	7.7%	7.2%	7.3%	8.8%	7.3%
	-$10 to -$20	6.3%	7.3%	6.6%	6.0%	3.3%	4.7%	3.6%	3.6%	5.1%	5.1%
	< -$20	7.3%	5.2%	7.9%	6.4%	4.1%	6.0%	3.6%	4.0%	7.9%	5.8%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	20.8%	21.2%	23.1%	33.9%	16.7%	21.1%	26.1%	12.9%	16.3%	21.3%
	$10 to $20	11.0%	9.1%	11.6%	11.9%	10.5%	7.2%	11.0%	9.1%	8.6%	10.0%
	$5 to $10	11.7%	12.7%	12.4%	11.2%	11.9%	9.3%	8.0%	9.7%	11.9%	11.0%
	$0 to $5	22.5%	20.4%	17.8%	15.2%	26.8%	25.8%	22.7%	28.1%	22.6%	22.5%
	$0 to -$5	17.4%	18.9%	15.3%	11.7%	21.2%	21.2%	19.6%	26.8%	22.0%	19.4%
	-$5 to -$10	6.1%	8.2%	7.1%	4.9%	5.3%	5.5%	5.5%	6.1%	7.2%	6.2%
	-$10 to -$20	5.3%	4.8%	5.5%	5.3%	3.7%	4.1%	3.5%	2.8%	3.5%	4.3%
	< -$20	5.1%	4.7%	7.1%	6.0%	3.9%	5.7%	3.6%	4.5%	8.0%	5.4%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	19.5%	16.4%	20.6%	28.3%	14.9%	21.6%	26.3%	14.4%	18.9%	20.1%
	$10 to $20	10.8%	11.6%	12.1%	12.6%	9.9%	7.8%	11.6%	7.9%	7.5%	10.2%
	$5 to $10	12.2%	12.7%	12.5%	12.5%	12.7%	9.7%	9.3%	9.8%	11.2%	11.4%
	$0 to $5	26.1%	23.2%	20.6%	16.8%	29.0%	28.3%	25.2%	29.6%	25.4%	24.9%
	$0 to -$5	17.4%	19.9%	15.3%	12.7%	21.8%	19.1%	17.7%	26.6%	20.2%	19.0%
	-$5 to -$10	5.3%	7.4%	6.5%	5.7%	4.6%	4.9%	4.4%	5.3%	6.5%	5.6%
	-$10 to -$20	4.2%	4.6%	5.3%	5.5%	3.3%	3.6%	2.3%	2.3%	2.9%	3.8%
	< -$20	4.7%	4.2%	7.2%	5.9%	3.7%	5.0%	3.2%	4.0%	7.4%	5.0%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	24.4%	26.6%	29.2%	30.4%	21.4%	24.3%	31.9%	18.5%	25.0%	25.7%
	$10 to $20	10.8%	10.4%	12.1%	12.8%	10.3%	8.0%	12.2%	8.7%	9.1%	10.5%
	$5 to $10	11.5%	9.8%	11.2%	11.6%	13.9%	10.7%	9.4%	10.5%	10.2%	11.0%
	$0 to $5	26.5%	21.7%	19.5%	18.3%	26.3%	29.2%	23.5%	29.9%	24.4%	24.4%
	$0 to -$5	15.7%	18.9%	13.6%	12.4%	19.4%	16.8%	15.1%	23.3%	17.2%	16.9%
	-$5 to -$10	4.9%	6.3%	5.3%	5.8%	3.5%	4.0%	3.1%	3.8%	5.3%	4.6%
	-$10 to -$20	3.2%	3.0%	4.4%	3.9%	2.7%	2.7%	1.9%	2.0%	2.7%	2.9%
	< -$20	3.1%	3.2%	4.7%	4.8%	2.6%	4.3%	2.8%	3.2%	6.1%	3.9%

Table 9-53 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January through September, 2025

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$50.90	$63.03	$67.05	$59.38	$50.13	$209.69	$206.32	$69.02	$75.07	$101.29
	$10 to $20	$14.27	$14.22	$14.46	$14.55	$14.41	$14.45	$14.35	$14.29	$13.85	$14.34
	$5 to $10	$7.39	$7.25	$7.35	$7.30	$7.27	$6.88	$7.29	$7.07	$7.14	$7.23
	$0 to $5	$2.27	$2.44	$2.38	$2.46	$2.03	$2.19	$2.02	$2.05	$2.11	$2.20
	$0 to -$5	$2.13	$2.40	$2.33	$2.04	$2.06	$2.09	$2.13	$1.99	$2.17	$2.13
	-$5 to -$10	$7.06	$7.14	$7.37	$7.06	$7.10	$6.98	$7.01	$6.95	$6.93	$7.07
	-$10 to -$20	$14.41	$13.78	$14.02	$14.40	$13.67	$14.39	$13.40	$13.91	$13.71	$14.01
	< -$20	$42.68	$42.96	$59.52	$74.38	$60.50	$125.39	$65.17	$75.90	$98.98	$72.45
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$52.70	$64.14	$68.59	$67.90	$47.41	$170.25	$147.66	$68.31	$70.83	$86.57
	$10 to $20	$14.43	$14.40	$14.43	$14.17	$14.01	$14.18	$14.46	$14.05	$13.95	$14.24
	$5 to $10	$7.22	$7.12	$7.44	$7.37	$7.16	$7.10	$7.33	$7.10	$7.25	$7.23
	$0 to $5	$2.22	$2.39	$2.48	$2.26	$2.13	$2.28	$1.99	$1.94	$2.10	$2.18
	$0 to -$5	$2.05	$2.13	$2.17	$1.99	$1.88	$1.89	$1.92	$1.81	$2.03	$1.97
	-$5 to -$10	$7.14	$7.30	$7.19	$7.27	$7.06	$6.95	$7.04	$7.04	$6.91	$7.10
	-$10 to -$20	$14.34	$14.12	$14.39	$14.06	$14.15	$14.36	$13.60	$13.81	$13.76	$14.11
	< -$20	$44.80	$44.38	$61.12	$72.08	$64.00	$139.38	$72.24	$79.28	$97.65	$77.01
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$49.13	$48.23	$53.37	$60.00	$54.70	$147.58	$107.73	$78.60	$69.07	$76.49
	$10 to $20	$14.38	$14.41	$14.17	$14.41	$13.67	$14.38	$14.55	$14.27	$14.20	$14.28
	$5 to $10	$7.12	$7.22	$7.32	$7.40	$7.11	$6.89	$7.34	$7.18	$7.25	$7.21
	$0 to $5	$2.14	$2.30	$2.40	$2.18	$2.16	$2.12	$2.05	$1.88	$2.07	$2.13
	$0 to -$5	$1.99	$1.97	$2.21	$2.00	$1.75	$1.81	$1.77	$1.69	$1.97	$1.88
	-$5 to -$10	$7.01	$7.24	$7.21	$7.25	$7.10	$6.93	$7.09	$7.01	$7.04	$7.11
	-$10 to -$20	$14.48	$14.05	$14.41	$14.70	$13.96	$14.15	$13.88	$13.96	$13.74	$14.22
	< -$20	$48.62	$47.02	$63.09	$76.18	$64.14	$116.58	$75.12	$84.73	$99.55	$76.54
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$81.50	$88.41	$97.10	$84.07	$88.74	$148.40	$102.36	$86.56	$105.57	$98.11
	$10 to $20	$14.45	$14.28	$14.40	$14.00	$14.19	$13.90	$14.33	$13.97	$13.95	$14.18
	$5 to $10	$7.11	$7.23	$7.37	$7.37	$7.06	$7.06	$7.25	$7.17	$7.18	$7.20
	$0 to $5	$2.15	$2.16	$2.43	$2.22	$2.16	$2.13	$2.14	$1.95	$2.13	$2.15
	$0 to -$5	$1.89	$2.02	$2.11	$1.94	$1.71	$1.74	$1.80	$1.69	$1.85	$1.84
	-$5 to -$10	$7.09	$7.07	$7.14	$7.17	$7.18	$7.20	$7.11	$7.02	$7.05	$7.11
	-$10 to -$20	$14.33	$14.14	$14.22	$14.09	$14.12	$13.86	$13.79	$14.77	$13.87	$14.14
	< -$20	$50.61	$46.71	$66.71	$82.44	$74.47	$130.98	$71.21	$92.23	$101.37	$82.85

CTS transactions were evaluated for each interval. From October 3, 2017, through September 30, 2025, 309,913 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 63,324 (20.4 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 20.4 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 79.6 percent of the intervals, the forecast price differentials were consistent with real-time PJM/MISO and MISO/PJM price differences. Figure 9-12 shows the monthly volume of cleared PJM/MISO CTS bids. Figure 9-12 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences. In June 2022, MISO experienced software issues that prevented the submission and clearing of CTS transactions. The issue was resolved in August 2022. It is unclear why market participants did not resume scheduling CTS transactions at the MISO interface until February 2023. Market participants did not use the MISO CTS transaction option between June 2024 and January 2025. While the forecast LMPs have not proven to be a good predictor of real time LMPs, that has not changed. It is not clear why market participants stopped using the MISO CTS transaction option during that time, or have not resumed using the option at volumes previously used.

Figure 9-12 Monthly cleared PJM/MISO CTS bid volume: October 3, 2017 through September 30, 2025



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. This limits 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 9-54 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 9-54 Monthly uncollected congestion charges: January 2010 through September 2025

Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0	$0	($69,992)	$0	$0	$0	$0	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
May	$41,025	$0	($27)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0	$0	($69,992)	$0	$0	$0	$0	$0	$0

Transmission Service Requests

Requests for transmission service are made on the PJM Open Access Same Time Information System (OASIS) on any of the posted paths. The products available on the OASIS include both firm and nonfirm service. Nonfirm service is available on an hourly, daily, weekly and monthly basis. Firm transmission service is defined as either short term or long term firm. Short term firm transmission is available on a daily, weekly or monthly basis, and long term firm is available for a period of one year or longer.

The total transfer capability (TTC) reflects the maximum amount of power that can be transferred over a transmission line or a group of transmission lines. In order to maintain reliability, transmission providers do not make the entire TTC available to be used. The available flowgate capability (AFC) is calculated for each path and product pair by taking the TTC and subtracting existing service requests, a capacity benefit margin[65], a transmission reliability margin[66] and taking postbacks and counterflows into consideration. The amount of transmission service that can be reserved is the Available Transfer Capability (ATC). The ATC is calculated for each path and product, and is determined by taking the AFC and adjusting it for all other committed transmission service requests that impact that path.

PJM calculates and posts ATC for all valid posted paths product pairs. The range of calculated ATCs depends on the duration of service. Hourly service is available up to seven days in advance, daily service is available 35 days in advance, weekly service is available five weeks in advance and monthly service is available 18 months in advance. Any transmission request that falls within the posted ATC period is evaluated based on the posted ATC. If there is sufficient capability, the transmission service request is accepted. If there is not sufficient capability, the transmission service request is denied.

Long term firm transmission service requests that extend beyond the ATC posting calculation are subject to system impact studies and must be submitted and evaluated in the new services queue. There is currently a backlog of projects in the new services queue. The backlog is being resolved through a transition to a new planning process, but new transmission service requests may not be evaluated or approved until 2027.[67]

Spot Imports

Figure 9-13 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through September 30, 2025. 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 9-13 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.[68]

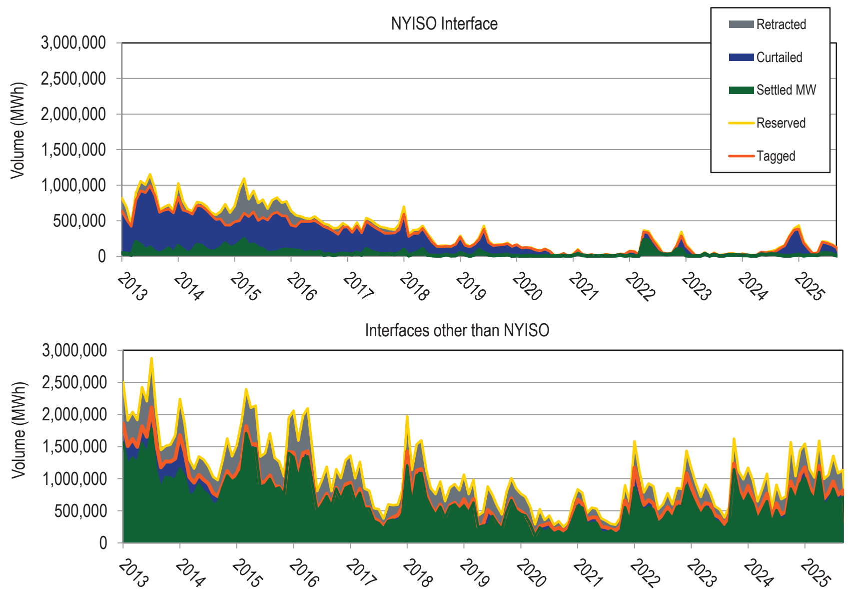
65 The capacity benefit margin is defined by NERC as "the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

66 The transmission reliability margin is defined by NERC as "the amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure".

67 See the *2025 Quarterly State of the Market Report for PJM: January through September*, Section 12, "Generation and Transmission Planning," for additional details.

68 See the *2018 Annual State of the Market Report for PJM*, Volume 2, Section 9, "Interchange Transactions," for a more complete discussion of the history of spot import transmission service.

Figure 9-13 Spot import service use: January 2013 through September 2025



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.

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 (EPT) 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.[69] 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.

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, are 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

69 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes. See *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, order on reh'g, Order No. 764-A, 141 FERC ¶ 61231 (2012).

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 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. 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 based on the assumption that the available generation in the PJM system can only move 1,000 MW over any 15 minute period, although there is no supporting analysis. As an example of how the ramp limit works, if at 0800 (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intrahour 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.[70] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[71]

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.[72]

MISO Multi-Value Project Usage Rate (MUR)

MISO defines a multi-value project (MVP) to be a project which, according to MISO, enables the reliable and economic delivery of energy in support of

70 *Id.* at P 51.
71 See *Id.* at P 12.
72 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>.

public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value. On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[73] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[74] 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 Order and MVP Rehearing Order.[75] 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.[76] 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.[77]

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[78] 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."[79]

The policy rationale for permitting MISO to impose transmission costs on PJM market participants without clear criteria is weak and results in pancaking of rates. The impact is expected to increase.

Table 9-55 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2024 through 2045.[80] As shown in Table 9-4, there were 4,672.1 GWh of imports from MISO in the first nine months of 2025. At the 2025 MUR of $1.57 per MWh, PJM market participants paid $7.3 million towards the costs of MISO's multi value projects. It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-55 MISO projected multi value project usage rate: 2025 through 2045

Year	Total Indicative MVP Usage Rate ($/MWh)
2025	$1.57
2026	$1.58
2027	$1.56
2028	$1.53
2029	$1.50
2030	$1.47
2031	$1.44
2032	$1.41
2033	$1.39
2034	$1.36
2035	$1.33
2036	$1.31
2037	$1.28
2038	$1.26
2039	$1.23
2040	$1.21
2041	$1.18
2042	$1.16
2043	$1.13
2044	$1.11
2045	$1.09

73 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
74 133 FERC ¶ 61,221; *order on reh'g*, 137 FERC ¶ 61,074 (2011).
75 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
76 *Id.* at 780.
77 *Id.* at 779.
78 156 FERC ¶ 61,034 (2016).
79 *Id.* at P 55.
80 See MISO, "Schedule 26A Indicative Annual Charges," (March 20, 2025) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.