



2025 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS

ANALYTIC APPENDIX

Prepared By:

**POTOMAC
ECONOMICS**

**Independent Market Monitor
for the Midcontinent ISO**

June 2026

TABLE OF CONTENTS

I.	Introduction.....	1
II.	Price and Load Trends	3
A.	Market Prices	3
B.	Fuel Prices and Energy Production.....	6
C.	Load and Weather Patterns	8
D.	Ancillary Services Markets.....	10
III.	Future Market Needs.....	15
A.	MISO’s Future Supply Portfolio.....	15
B.	The Evolution of the MISO Markets to Satisfy MISO’s Reliability Imperative	19
IV.	Energy Market Performance and Operations	21
A.	Day-Ahead Energy Prices and Convergence with Real-Time Prices	21
B.	Day-Ahead Load Scheduling.....	26
C.	Load Forecasting.....	29
D.	Hourly Day-Ahead Scheduling.....	29
E.	Virtual Transactions in the Day-Ahead Market.....	30
F.	Virtual Profitability.....	36
G.	Benefits of Virtual Trading.....	38
H.	Evaluation of ELMP Effects	40
I.	Spinning Reserve Shortages	43
J.	Supplemental Reserve Deployments	44
K.	Uplift Costs: RSG Payments.....	45
L.	Uplift Costs: Price Volatility Make-Whole Payments.....	48
M.	Real-Time Commitment Patterns	50
N.	Generation Availability and Flexibility in Real Time	51
O.	Look Ahead Commitment Performance Evaluation.....	52
P.	Real-Time Dispatch Performance.....	53
Q.	Coal Resource Operations.....	60
R.	Dispatch of Peaking Resources.....	61
S.	Wind and Solar Generation.....	62
T.	Outage Scheduling	67
V.	Transmission Congestion and FTR Markets	69
A.	Real-Time Value of Congestion	69
B.	Day-Ahead Congestion and FTR Funding	71
C.	FTR Market Performance	74
D.	Multi-Period Monthly FTR Auction Revenues and Obligations.....	83
E.	Market-to-Market Coordination with PJM and SPP.....	86
F.	Congestion on Other External Constraints	96
G.	Congestion Manageability	98
H.	Transmission Ratings and Constraint Limits.....	100

I.	Operator Congestion Management Actions.....	104
J.	Other Key Congestion Management Issues.....	107
VI.	Resource Adequacy.....	111
A.	Regional Generating Capacity	111
B.	Changes in Capacity Levels.....	112
C.	Planning Reserve Margins and Summer Readiness.....	112
D.	Long-Term Economic Signals	114
E.	Existing Capacity at Risk Analysis.....	116
F.	Capacity Market Reforms	117
VII.	External Transactions	119
A.	Overall Import and Export Patterns	119
B.	Coordinated Transaction Scheduling.....	122
C.	Interface Pricing and External Transactions	125
D.	Price Convergence Between MISO and Adjacent Markets	128
VIII.	Competitive Assessment and Market Power Mitigation.....	129
A.	Structural Market Power Indicators	129
B.	Participant Conduct – Potential Economic Withholding.....	133
C.	Market Power Mitigation.....	139
D.	Evaluation of RSG Conduct and Mitigation Rules.....	140
E.	Participant Conduct – Ancillary Services Offers.....	142
F.	Participant Conduct – Physical Withholding.....	144
IX.	Demand Response Programs	147
A.	Demand Response Participation in MISO	147

TABLE OF FIGURES

Figure A1: All-In Price of Electricity	3
Figure A2: Cross Market All-In Price Comparison	4
Figure A3: Real-Time Energy Price-Duration Curve	5
Figure A4: MISO Fuel Prices	5
Figure A5: Implied Marginal Heat Rate	6
Figure A6: Price-Setting by Unit Type	7
Figure A7: Load Duration Curves and 2025 Peak Load	8
Figure A8: Heating and Cooling Degree-Days	9
Figure A9: Real-Time ASM Prices and Shortage Frequency	11
Figure A10: Regulation Offers and Scheduling	12
Figure A11: Contingency Reserve Offers and Scheduling	13
Figure A12: Short-Term Reserves and Ramp Product Prices	14
Figure A13: Anticipated Resource Mix: 2032 and 2042	15
Figure A14: Share of MISO Load Served by Wind and Solar Generation Over Time	16
Figure A15: Midwestern Load Share Served by Wind and Solar Generation Over Time	17
Figure A16–A17: Daily Range of Wind Generation Output	17
Figure A18: Net Load Ramp in MISO	19
Figure A19: Uncertainty and MISO’s Operating Requirements	20
Figure A20–A21: Day-Ahead Hub Prices and SMP	21
Figure A22–A27: Day-Ahead and Real-Time Prices	23
Figure A28: Day-Ahead Ancillary Services Prices and Price Convergence	26
Figure A29: Day-Ahead Scheduled Versus Actual Loads	27
Figure A30: MISO Midwest Day-Ahead Scheduled Versus Actual Loads	28
Figure A31: MISO South Day-Ahead Scheduled Versus Actual Loads	28
Figure A32: Ramp Demand Impact of Hourly Day-Ahead Market	30
Figure A33: Day-Ahead Virtual Transaction Volumes	31
Figure A34: Day-Ahead Virtual Transaction Volumes by Region	32
Figure A35–A37: Virtual Transaction Volumes by Participant Type	33
Figure A38: Virtual Transaction Volumes by Participant Type and Location	34
Figure A39: Matched Price-Insensitive Virtual Transactions	35
Figure A40: Comparison of Virtual Transaction Levels	36
Figure A41: Virtual Profitability	37
Figure A42: Virtual Profitability by Participant Type in 2025	37
Figure A43: The Effects of Fast Start Pricing in ELMP	41
Figure A44: Average Market-Wide Price Effects of ELMP	41
Figure A45: Price Effects of ELMP at Most Affected Locations	42
Figure A46: Actual EEA2 Pricing and RDT Flows	42
Figure A47: Simulated, Proposed EEA2 Pricing and RDT Flows	43
Figure A48: Market Spin Shortage Intervals Versus Rampable Spin Shortage Intervals	44
Figure A49: Supplemental Reserve Deployments	44
Figure A50: Day-Ahead RSG Payments	46
Figure A51: Real-Time RSG Payments	46
Figure A52: RSG for Units Committed for RDT	47
Figure A53: Allocation of RSG Charges	48
Figure A54: Monthly Real-Time Capacity Commitments and RSG Costs	51

Figure A55: Changes in Supply from Day Ahead to Real Time	52
Figure A56: Economic Evaluation of LAC Commitments.....	53
Figure A57–A58: Frequency of Net Deviations	54
Figure A59–A61: 60-Minute Deviation by Fuel and Hour	56
Figure A62: Hourly 60-Minute Deviations by Type of Conduct	57
Figure A63: DAMAP to Dragging Units by Fuel Type	58
Figure A64: Excess Operating Reserve Payments to Units not Following Dispatch	59
Figure A65: Dispatch of Peaking Resources	62
Figure A66: Virtual Impacts on Top 10 Constraints Affected by Wind.....	64
Figure A67: Generation Wind Over-Forecasting Levels.....	65
Figure A68: Wind Forecast Methodology Improvement.....	66
Figure A69: Wind Generation Volatility	66
Figure A70: Wind Generation Capacity Factors	67
Figure A71: Generation Outages	68
Figure A72: Value of Real-Time Congestion by Coordination Region	70
Figure A73: Value of Real-Time Congestion by Type of Constraint.....	71
Figure A74: Day-Ahead and Balancing Congestion and FTR Funding.....	72
Figure A75: FTR Funding by Control Area	73
Figure A76: Balancing Congestion Revenues and Costs	74
Figure A77: FTR Profits and Profitability	75
Figure A78–A80: FTR Profitability.....	76
Figure A81–A92: Comparison of FTR Auction Prices and Congestion Value.....	77
Figure A93: Prompt-Month MPMA FTR Profitability	84
Figure A94: CROW Outage Tickets by Creation Date	85
Figure A95: Monthly FTR Valuation Changes for Aggregate Nodes	85
Figure A96: Market-to-Market Events: MISO and PJM	86
Figure A97: Market-to-Market Events: MISO and SPP.....	87
Figure A98: Market-to-Market Settlements.....	87
Figure A99: Congestion Costs on PJM and SPP Flowgates.....	89
Figure A100: Share of the Relief from the MRTTO	90
Figure A101: Share of Economic Relief on SPP-Owned Flowgates in 2025.....	92
Figure A102: Shadow Price Convergence MISO-SPP in 2025.....	93
Figure A103: Shadow Price Convergence MISO-PJM in 2025	93
Figure A104: JOA Uplift Impact of Shadow Price Non-Convergence MISO-SPP	94
Figure A105: JOA Uplift Impact of Shadow Price Non-Convergence MISO-PJM.....	95
Figure A106: Monthly Balancing Congestion Revenue	96
Figure A107: Real-Time Valuation Effect of TLR Constraints	97
Figure A108: Constraint Manageability	99
Figure A109: Real-Time Congestion Value by Voltage Level	100
Figure A110: Potential Value of Additional Transmission Capability.....	101
Figure A111: Estimated Actual Savings of AARs	102
Figure A112: Area-Specific Savings Potential of Ratings Enhancement.....	103
Figure A113: Value of Unrealized Transmission Flows from Limit Control Derates	104
Figure A114: Manual Redispatch, Caps, and TCDC Actions	105
Figure A115: Limit Control Case Studies	106
Figure A116: LAC Decommitment Case Study Savings	108

Figure A117: Congestion Savings and Shadow Price Changes.....	109
Figure A118: Congestion Affected by Multiple Planned Generation Outages	110
Figure A119: Distribution of Existing Generating Capacity	111
Figure A120: Distribution of Additions and Retirements of Generating Capacity	112
Figure A121–A122: Net Revenue Analysis	115
Figure A123: Capacity at Risk by Technology Type	117
Figure A124: Estimated Midwest Capacity Replacement Settlement Prices	118
Figure A125: Estimated South Capacity Replacement Settlement Prices.....	118
Figure A126: Average Hourly Day-Ahead Net Imports.....	119
Figure A127: Average Hourly Real-Time Net Imports.....	120
Figure A128: Average Hourly Day-Ahead Net Imports.....	120
Figure A129: Average Hourly Real-Time Net Imports by Interface.....	121
Figure A130: Average Hourly Real-Time Net Imports from PJM.....	121
Figure A131: Average Hourly Real-Time Net Imports from Canada	122
Figure A132: CTS Versus Traditional NSI Scheduling	123
Figure A133: MISO and PJM CTS Forecast Errors	124
Figure A134: Interchange Optimization Benefit Estimate	125
Figure A135: Constraint-Specific Interface Congestion Prices.....	127
Figure A136: Real-Time Prices and Interface Schedules	128
Figure A138: Market Shares and Market Concentration by Region	129
Figure A139: Pivotal Supplier Frequency by Region and Load Level.....	130
Figure A140: Percentage of Intervals with at Least One Pivotal Supplier	132
Figure A141: Percentage of Active Constraints with a Pivotal Supplier.....	132
Figure A142: Economic Withholding – Output Gap Analysis.....	136
Figure A143–A146: Real-Time Average Output Gap and Load.....	137
Figure A147: Day-Ahead and Real-Time Energy Offer Mitigation by Month.....	139
Figure A148: Day-Ahead and Real-Time RSG Mitigation by Month	140
Figure A149–A151: Real-Time RSG Payments by Conduct	141
Figure A152–A154: Ancillary Services Market Offers.....	143
Figure A155–A157: Real-Time Deratings and Forced Outages.....	145

TABLE OF TABLES

Table A1: Capacity, Energy Output, and Price-Setting by Fuel Type.....	8
Table A2: Comparison of Virtual Trading Volumes and Profitability	36
Table A3: Efficient and Inefficient Virtual Transactions in 2025	39
Table A4: Efficient and Inefficient Virtual Transactions in 2025 – Financial Participants	39
Table A5: Efficient and Inefficient Virtual Transactions in 2025 – Physical Participants.....	39
Table A6: Price Volatility Make-Whole Payments (\$ Millions)	49
Table A7: Causes of DAMAP	50
Table A8: Average Five-Minute and Sixty-Minute Net Dragging	55
Table A9: Proposed Uninstructed Deviation Penalties and Effective Rate	58
Table A10: Proposed Emergency-Range Penalties	60
Table A11: Coal-Fired Resource Operation and Profitability	61
Table A12: Day-Ahead and Real-Time Wind and Solar Generation	63
Table A13: Aggregate Virtual Impacts on Constraints Affected by Wind.....	64
Table A14: Real-Time Congestion on Constraints Affected by Market-to-Market Issues	88
Table A15: Shadow Price Convergence on M2M Flowgates with SPP in 2025.....	91
Table A16: Economic Relief from TVA and AECI Generators on MISO Constraints.....	98
Table A17: Case Studies Selected for LAC Decommitment Analysis.....	107
Table A18: Summer 2026 Planning Reserve Margins	114
Table A19: Demand Response Capability in MISO and Neighboring RTOs	148

I. INTRODUCTION

This Analytic Appendix provides an extended analysis of the topics raised in the main body of the State of the Market Report. We present the assumptions, methods, and motivation for each of the analyses. Therefore, it is intended to serve as a useful reference document to accompany the report since our conclusions from these analyses and how they relate to the performance of the markets are discussed in the report. In addition, the body of the report includes a discussion of our recommendations to improve the design and competitiveness of the market.

The sections and analyses are intended to track the order of topics in the main body of the State of the Market Report. However, this appendix contains many figures and tables that are not included in the report. These figures and tables provide additional insight and detail or show the analytic results in a more disaggregated form.

We want to express our appreciation to MISO staff for their cooperation and support in providing data, other information, and feedback on numerous topics and issues addressed in this report.

II. PRICE AND LOAD TRENDS

In this section, we provide our analyses of the prices and outcomes in MISO’s day-ahead and real-time energy markets.

A. Market Prices

In a well-functioning, competitive market, suppliers have an incentive to offer at their marginal costs. Therefore, energy prices should correspond closely with resources’ marginal production costs, which are primarily comprised of fuel costs for most resources.

Figure A1: All-In Price of Electricity

Figure A1 shows the monthly “all-in” price of electricity from 2024 to 2025 along with the price of natural gas at the Chicago Citygate trading hub. The leftmost section shows the annual average prices for 2020 through 2025. The all-in price represents the cost of serving load in MISO’s electricity market. It includes the load-weighted real-time energy cost, as well as real-time ancillary services costs, uplift costs, and capacity costs—Planning Reserve Auction (PRA) clearing price multiplied by the capacity requirement—per MWh of real-time load. We separately show the portion of the all-in energy price that is associated with shortage pricing for one or more products.

Figure A1: All-In Price of Electricity
2024–2025

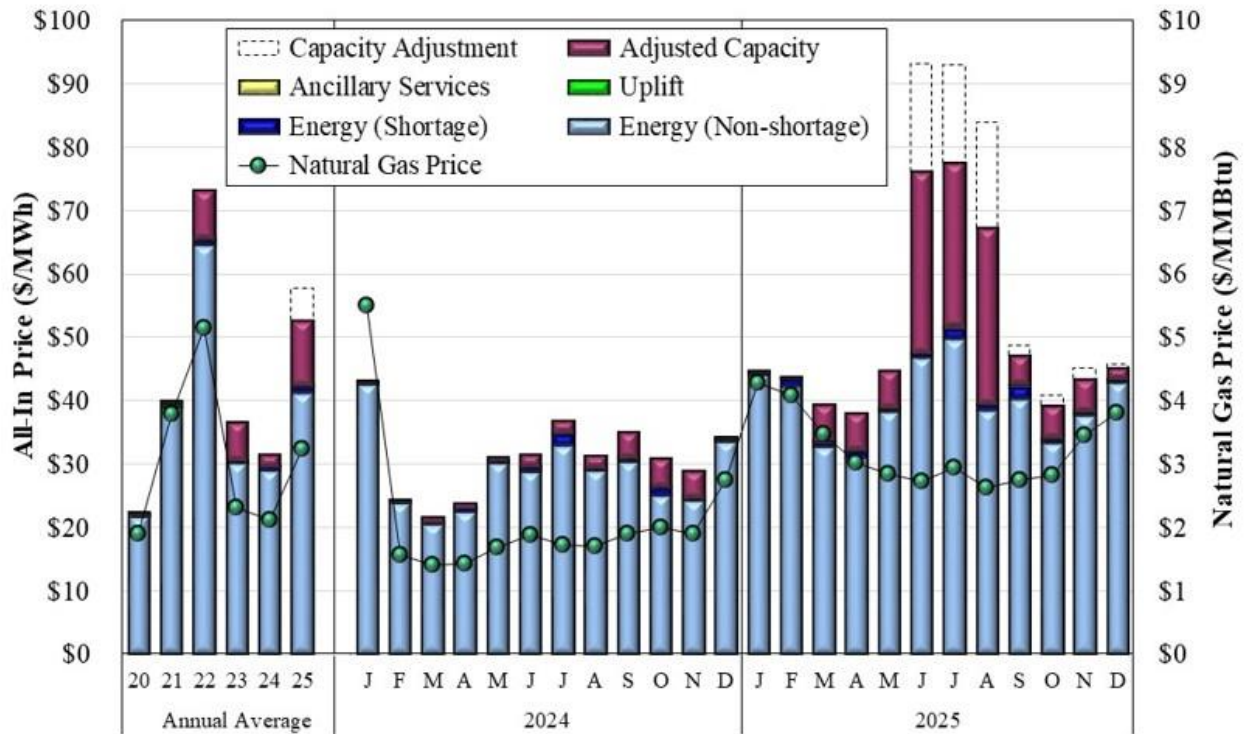


Figure A2: Cross Market All-In Price Comparison

Figure A2 compares all-in prices in MISO and the other eastern RTOs from 2023 through 2025. These markets have migrated to similar market designs, including locational energy markets, operating reserves and regulation markets, and capacity markets (except ERCOT and SPP). However, their market rules can vary substantially.

Figure A2: Cross Market All-In Price Comparison
2023–2025

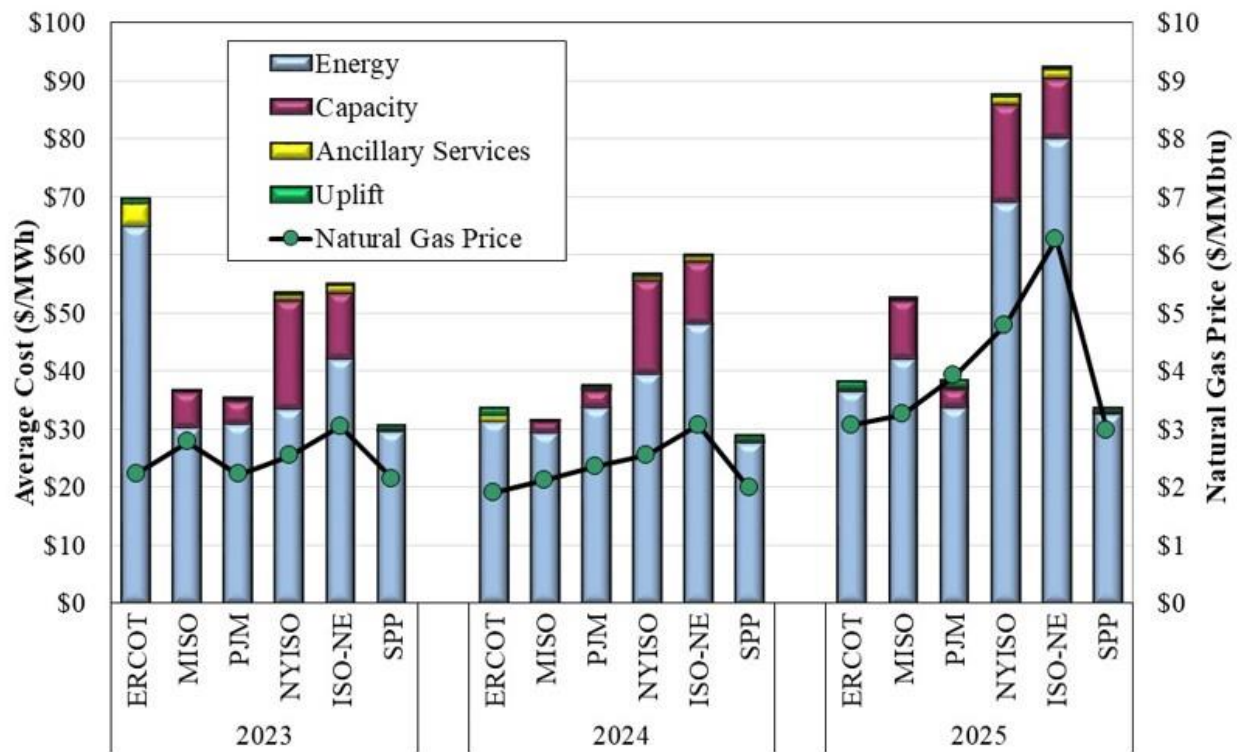


Figure A3: Real-Time Energy Price-Duration Curves

Figure A3 shows the real-time hourly prices at seven representative locations in MISO in the form of a price-duration curve. A price-duration curve shows the number of hours (on the horizontal axis) when the Locational Marginal Price (LMP) is greater than or equal to a particular price level (on the vertical axis). The differences between the curves in this figure are due to congestion and losses, which cause energy prices to vary by location.

The table inset in the figure shows the percentage of hours in the three most recent years with prices greater than \$200, greater than \$100, and less than \$0 per MWh. The highest prices often occur during peak load periods when shortage conditions are most common. Prices in these hours are an important component of the economic signals that govern investment and retirement decisions. Broad price changes generally result from changes in underlying fuel prices that affect many hours. In contrast, price changes at the high end of the duration curve usually result from differences in weather-related peak loads that affect the frequency of shortage conditions.

**Figure A3: Real-Time Energy Price-Duration Curve
2023–2025**

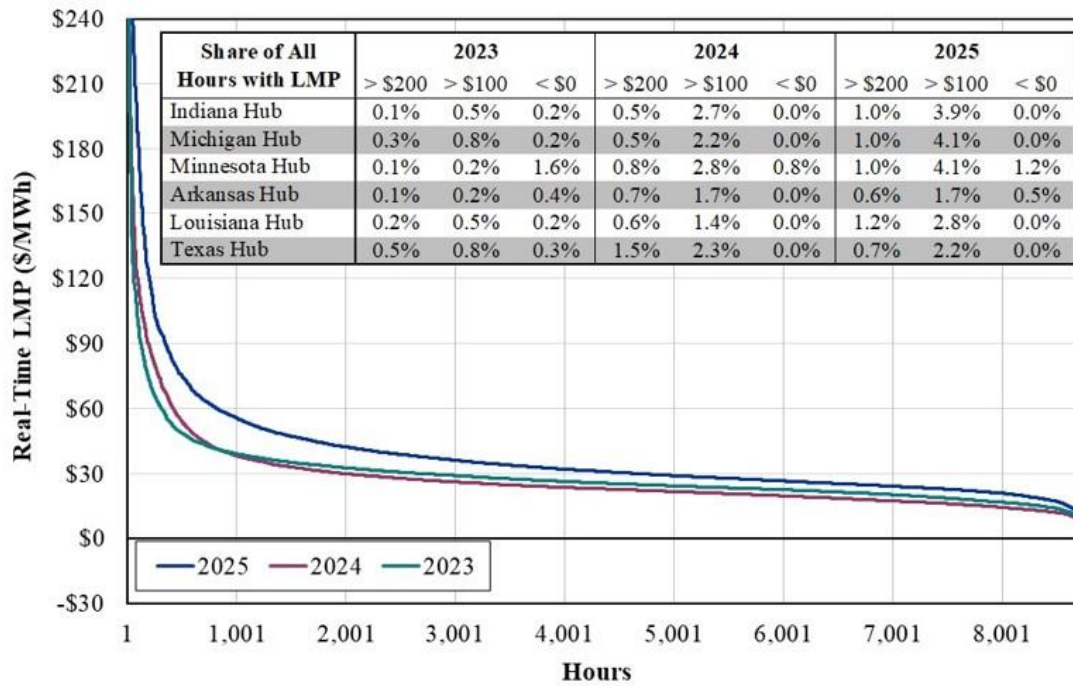


Figure A4: MISO Fuel Prices

Fuel prices are a primary determinant of energy prices because they account for most generators' marginal costs. Natural gas-fired resources set energy prices in most peak hours, and coal-fired units set them in many off-peak hours. Figure A4 shows both fuel prices at multiple locations.

Figure A4: MISO Fuel Prices

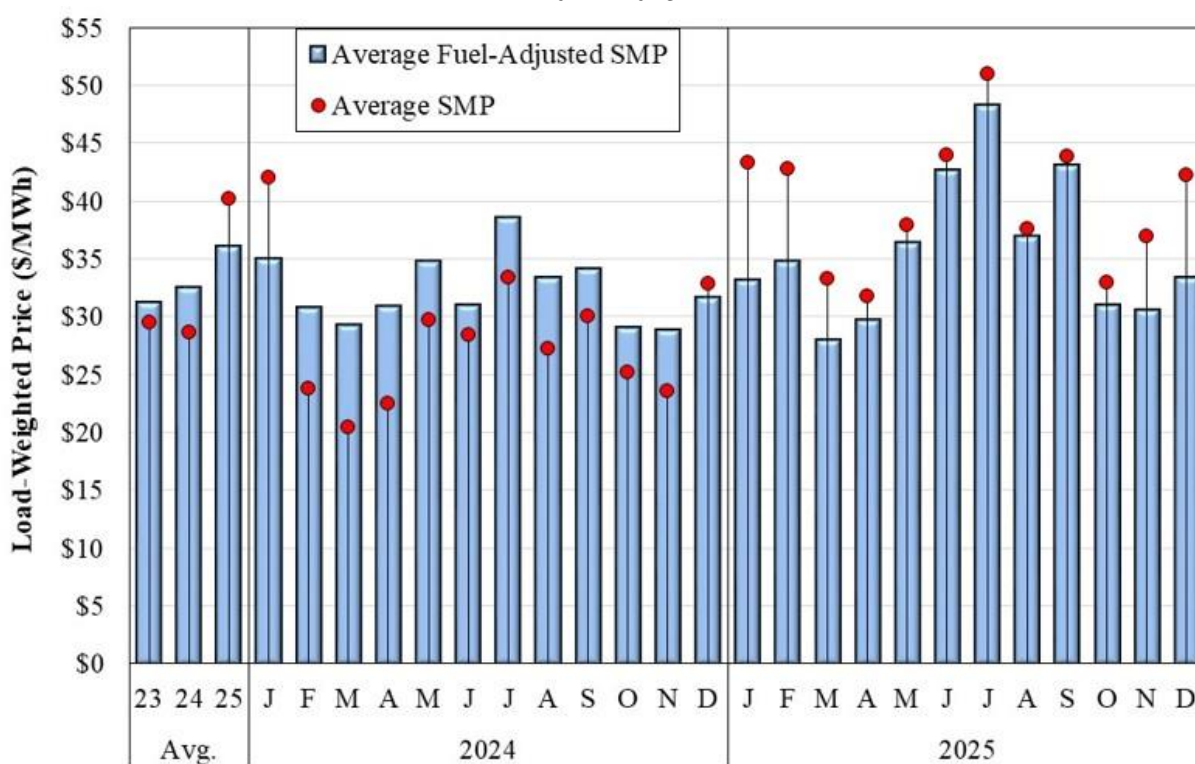


Figure A4 shows prices for natural gas at Henry Hub and Chicago Citygate and for two types of coal in the MISO region since the beginning of 2024. It reports nominal prices in dollars per million British thermal units (MMBtu). The table below the figure shows the annual average nominal prices for each type of fuel from 2023 and 2025.

Figure A5: Implied Marginal Heat Rate

Fluctuations in marginal fuel prices can obscure underlying trends in electricity market performance. To estimate the effects on prices of factors other than changes in fuel prices, we calculate an “implied marginal heat rate” by dividing the real-time energy price by the natural gas price. Figure A5 shows the monthly and annual average implied marginal heat rates as blue bars on the left axis and the average nominal system marginal price (SMP) as red diamonds on the right axis. We first calculate a daily implied heat rate by dividing the daily average SMP by the daily maximum gas price between Chicago Citygate and the Henry Hub. We then average the daily values within each month to calculate the monthly averages.

Figure A5: Implied Marginal Heat Rate
2024–2025



B. Fuel Prices and Energy Production

Figure A6: Price Setting by Unit Type

Figure A6 shows how often different types of generating resources set the real-time SMP in MISO. The top panel shows the average prices when each unit type was on the margin, and the bottom panel shows the share of market intervals in which each unit type set the real-time price.

Baseload coal-fired units historically set prices in the majority of hours, but that share has declined over time. 2018 was the first year that coal resources set the marginal energy price less frequently than gas-fired resources. Nearly all wind resources can be economically curtailed when they contribute to transmission congestion. Because their incremental costs largely reflect lost production tax credits, wind units often set negative prices in export-constrained areas when operators must ramp them down to manage congestion.

Figure A6: Price-Setting by Unit Type
2024–2025

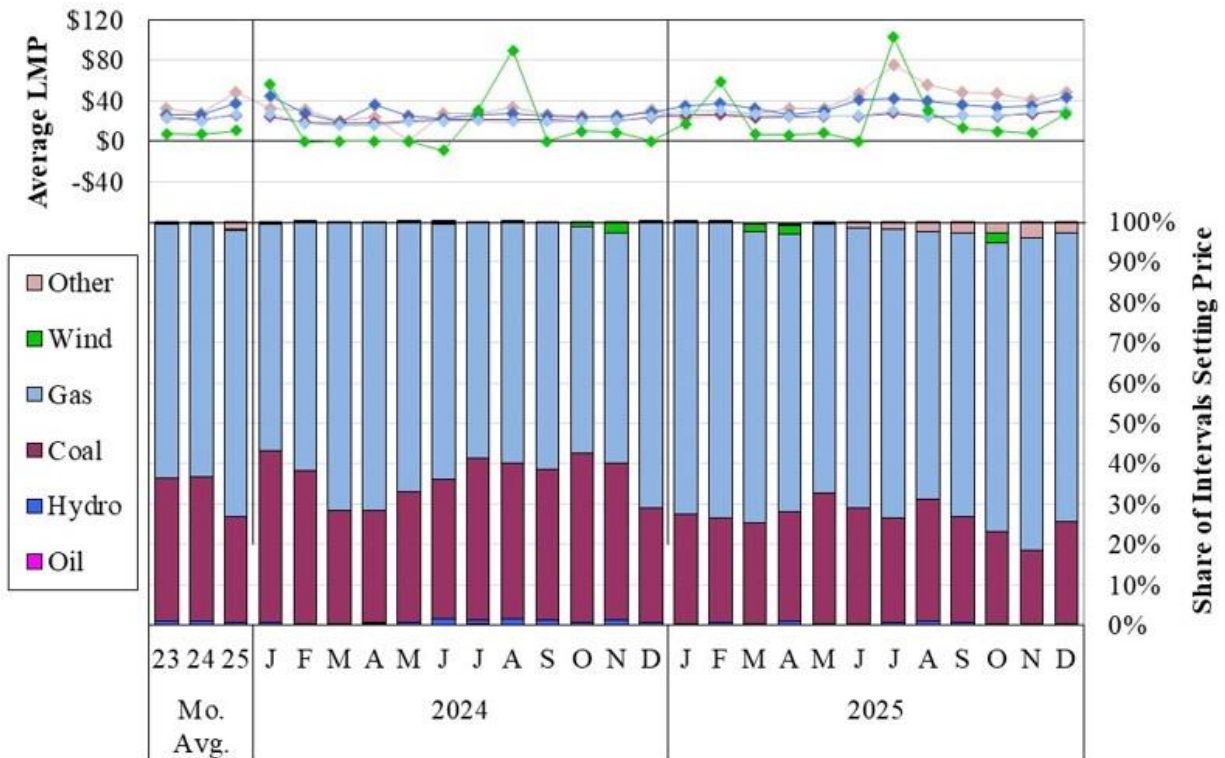


Table A1: Capacity, Energy Output, and Price-Setting by Fuel Type

Table A1 summarizes how changes in fuel prices have affected the share of energy produced by each fuel type, and the generators that set the real-time energy prices in 2025 compared to 2024. The lowest marginal cost resources (coal and nuclear) produce about 40 percent of the total energy. Because natural gas-fired units have higher marginal costs, they tend to produce a lower share of MISO's energy than their share of MISO's installed capacity. Although wind and solar resources comprise a small share of MISO's Unforced Capacity (UCAP) because of their intermittent nature, their contribution to energy output is often higher.

**Table A1: Capacity, Energy Output, and Price-Setting by Fuel Type
2024–2025**

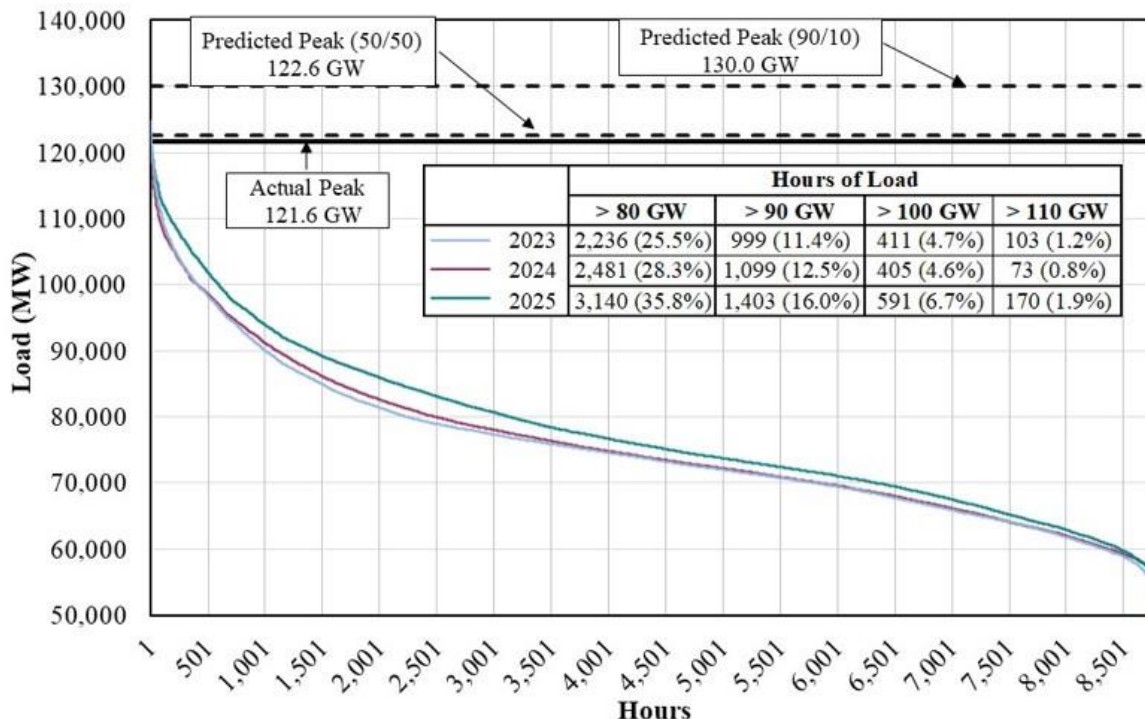
	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025
Nuclear	10,987	11,124	8%	8%	14%	14%	0%	0%	0%	0%
Coal	36,880	36,174	28%	27%	26%	29%	33%	26%	75%	64%
Natural Gas	64,269	65,525	48%	49%	38%	35%	65%	72%	91%	91%
Oil	1,430	1,319	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,813	3,883	3%	3%	1%	1%	1%	0%	2%	2%
Wind	11,504	8,236	9%	6%	15%	15%	0%	1%	64%	60%
Solar	3,471	6,228	3%	5%	2%	5%	0%	0%	10%	17%
Battery	265	790	0%	1%	0%	0%	0%	2%	0%	2%
Other	1,176	1,029	1%	1%	3%	1%	0%	0%	2%	3%
Total	132,620	133,278								

C. Load and Weather Patterns

Figure A7: Load Duration Curves and 2025 Peak Load

Although market conditions can still be tight in the winter and shoulder seasons because of generation and transmission outages and fuel supply issues, MISO continues to be a summer-peaking market. Figure A7 shows load levels for 2025 and the prior two years as hourly load duration curves. The horizontal axis shows the number of hours in which load is greater than or equal to the level on the vertical axis. The figure shows separate curves for 2023 through 2025.

**Figure A7: Load Duration Curves and 2025 Peak Load
2023–2025**

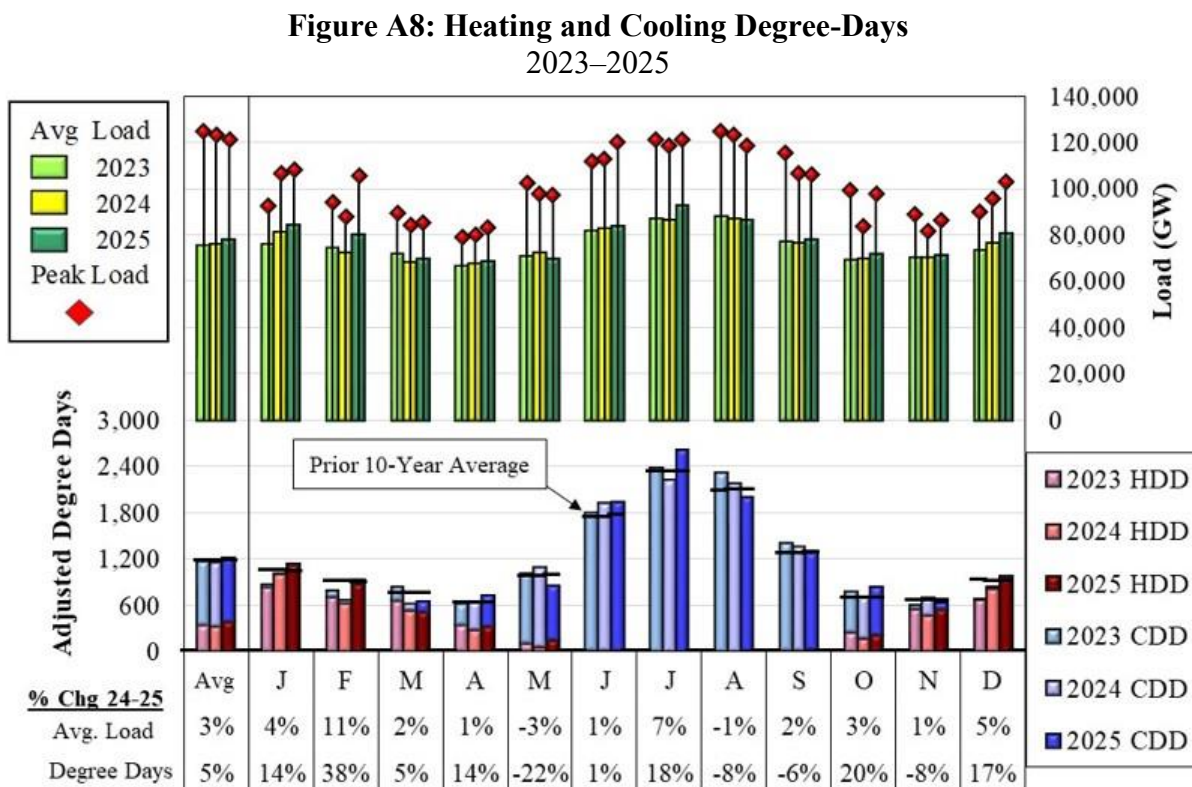


Load duration curves reveal the changes in load that are due to economic activity and weather conditions, among other things. The inset table indicates the number and percentage of hours when load exceeded 80, 90, 100, and 110 GW. The figure shows the actual and predicted peak load for 2025. The “Predicted Peak (50/50)” is the predicted peak load where MISO expected the load could be higher or lower than this level with equal probability. The “Predicted Peak (90/10)” is the predicted peak load where actual peak will be at or below this level with 90 percent probability (i.e., there is only a 10 percent probability of load peaking above this level).

Figure A8: Heating and Cooling Degree-Days

MISO’s load is temperature sensitive. Figure A8 illustrates the influence of weather on load by showing heating and cooling degree-days that are a proxy for weather-driven demand for energy. These are shown along with the monthly average load levels for the prior three years.

The top panel shows the monthly average loads in the bars and the peak monthly load in the diamonds. The bottom panel shows monthly Heating Degree-Days (HDD) and Cooling Degree-Days (CDD) averaged over the 10 years prior to 2025 across four representative cities in MISO Midwest and two cities in MISO South.¹ The table at the bottom shows the year-over-year changes in average load and degree-days.



¹ HDDs and CDDs are defined using daily temperature observations relative to a base temperature (in this case, 65 degrees Fahrenheit). For example, a mean temperature of 25 degrees Fahrenheit in a particular week in Minneapolis results in $(65-25) * 7 \text{ days} = 280 \text{ HDDs}$. To account for the relative impact of HDDs and CDDs, HDDs are inflated by a factor of 6.07 to normalize the effects on load (i.e., so that one adjusted-HDD has the same impact on load as one CDD). This factor was estimated using a regression analysis.

D. Ancillary Services Markets

MISO’s real-time market software jointly optimizes the scheduling of energy and operating reserves, which include regulating reserves and contingency reserves. As a result, opportunity cost trade-offs increase energy and reserve prices. Reserve shortages also affect prices in energy and ancillary services markets (ASM). When the market is short of one or more ancillary services products, the demand curve for that product sets the market-wide price for that product and is included in the price of higher-valued reserves and energy. Ancillary services products include regulation, Short-Term Reserves (STR), and contingency reserves, which are comprised of spinning reserves and supplemental reserves.² Total operating reserves are the sum of these products.

The demand curves for the ancillary services products in 2025 were:

- Regulation: varies monthly with the prior month’s gas prices and averaged \$236.21 per MWh.
- Spinning Reserves: \$65 per MWh (for shortages between zero and 10 percent of the market-wide requirement) and \$98 per MWh (for shortages greater than 10 percent).³
- Total Operating Reserves:⁴
 - For cleared reserves less than four percent of the market-wide requirement, the price is the Value of Lost Load (\$10,000 per MWh) minus the monthly demand curve price for regulation.
 - For cleared reserves between four and twelve percent, the estimated probability of lost load is based on a single large resource contingency.
 - For cleared reserves between twelve percent and the Most Severe Single Contingency, the curve is flat at \$2,100 per MWh and then steps down to \$1,100 per MWh.
- Short-Term Reserves: In November 2022, MISO implemented a multi-step curve with a high step of \$500 per MWh, replacing the previous curve set at \$100 per MWh.

The most important reserve constraint is the market-wide operating reserve requirement (contingency reserves plus regulation) because a shortage of total operating reserves has the greatest potential impact on reliability. Accordingly, the total operating reserve constraint has the highest-priced reserve demand curve. As increasing load and unit retirements reduce the capacity surplus in MISO, more frequent operating reserve shortages will play a key role in providing long-term economic signals to invest in new resources.

² Contingency Reserves provide a 10-minute response rate, whereas STR provide a 30-minute response rate.

³ There is an additional \$50 per MWh penalty called the “MinGenToRegSpinPenalty.”

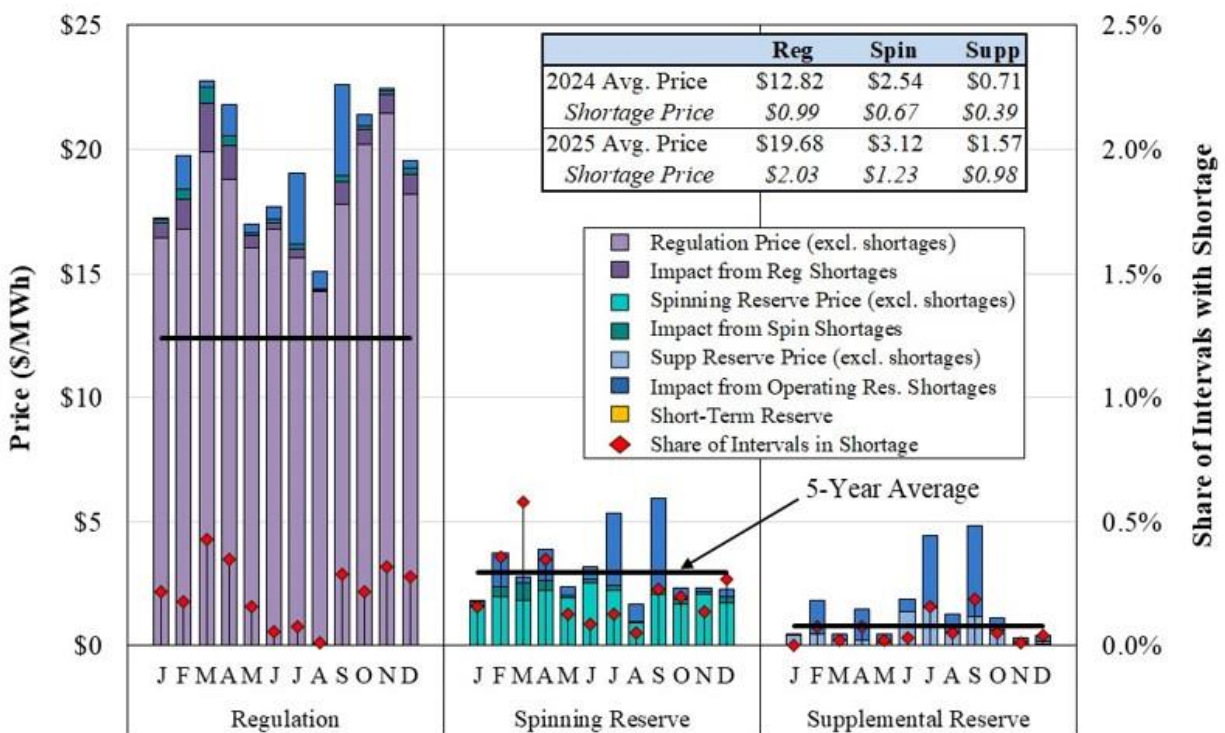
⁴ There is no separate demand curve for Supplemental Reserves. Prices for Supplemental Reserves during shortages are established by the Total Reserve demand curve (known as the operating reserve demand curve or ORDC).

Figure A9: Real-Time Ancillary Services Clearing Prices and Shortages

Figure A9 shows monthly average real-time clearing prices for the four ancillary service products: regulation, spinning reserves, supplemental reserves, and STR.

Supplemental reserves are the lowest-quality contingency reserve because their technical requirements are less stringent than those for regulation and spinning reserves. Because supplemental reserves will be short whenever total reserves are short, a supplemental reserve shortage is an operating reserve shortage. This results in the largest shortage-pricing component in the other reserve prices and the energy price. Figure A9 shows how often the system was short of each reserve class and the impact of each product's shortage pricing.

Figure A9: Real-Time ASM Prices and Shortage Frequency
2025



Note: Supplemental Reserve shortages in the figure reflect Operating Reserve shortages.

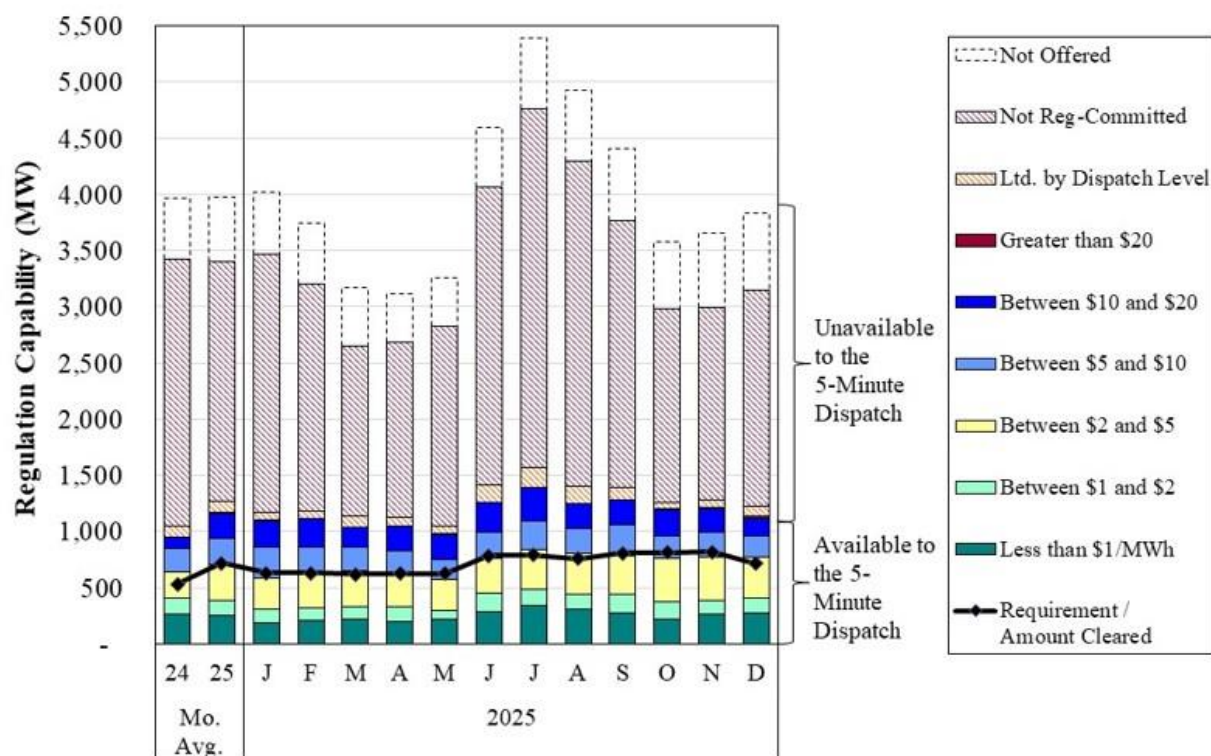
Additionally, higher-quality reserves can always substitute for lower-quality reserves. Therefore, spinning reserve prices will always be equal to or higher than supplemental reserve prices. Likewise, a shortage in a lower-quality reserve product appears in the prices of all higher-quality reserves.

Figure A10: Regulation Offers and Scheduling

ASM offer prices and quantities primarily determine ASM outcomes. Figure A10 shows average regulation capability for MISO resources. Regulation capability is less than spinning reserve capability because only regulation-capable resources can provide it, and it is limited to five minutes of bi-directional ramp capability.

Clearing prices for regulating reserves can be considerably higher than the highest-cleared regulation offer prices because they reflect the opportunity cost of dispatching resources up or down from their economic level to provide bi-directional regulation capability. In addition, regulation, as the highest-quality ancillary service, can substitute for either spinning or supplemental reserves. Hence, shortages in those products will also be reflected in the regulating reserve price.

Figure A10: Regulation Offers and Scheduling
2025



The figure above distinguishes between the regulation that is available to the five-minute dispatch in the solid bars and quantities that are unavailable in the hashed bars. The figure separately shows the quantities unavailable because they are not offered by participants, not committed by MISO, or limited by dispatch level (i.e., constrained by a unit's operating limits).

Figure A11: Contingency Reserve Offers and Scheduling

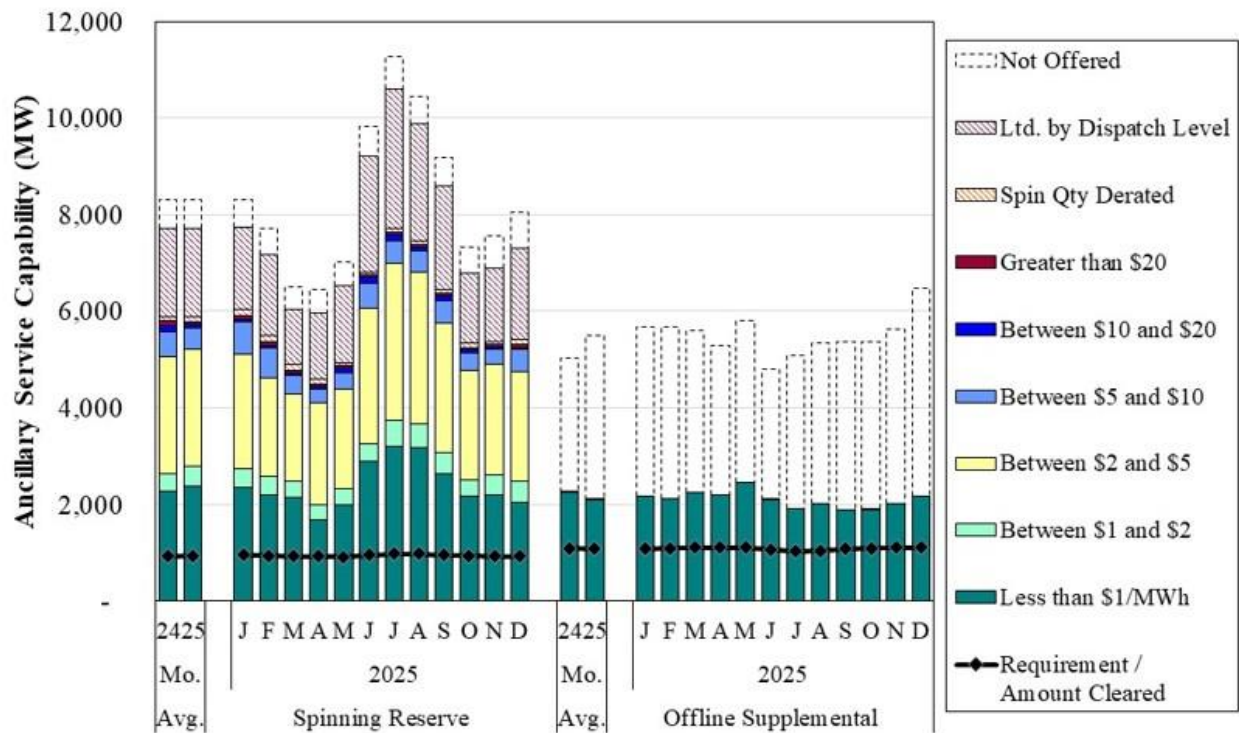
MISO has two classes of contingency reserves: spinning reserves and supplemental reserves. Online resources can provide spinning reserves for up to 10 minutes of ramp capability, limited by available headroom above their output level. Offline units that can respond within 10 minutes, including startup and notification times, provide supplemental reserves. The sum of spinning and supplemental reserves satisfies the contingency reserve requirement.

Higher-valued reserves can fulfill the requirements of lower-quality reserves. Therefore, regulation prices always equal or exceed spinning reserve prices, which in turn always equal or

exceed supplemental reserve prices. As with regulation, spinning and supplemental reserve prices can exceed the highest cleared offer because of opportunity costs or shortage pricing.

Figure A11 shows spinning and supplemental reserve offer quantities by offer price. For capability unavailable for dispatch, the figure distinguishes quantities that were not offered, were derated, or were limited by dispatch level.

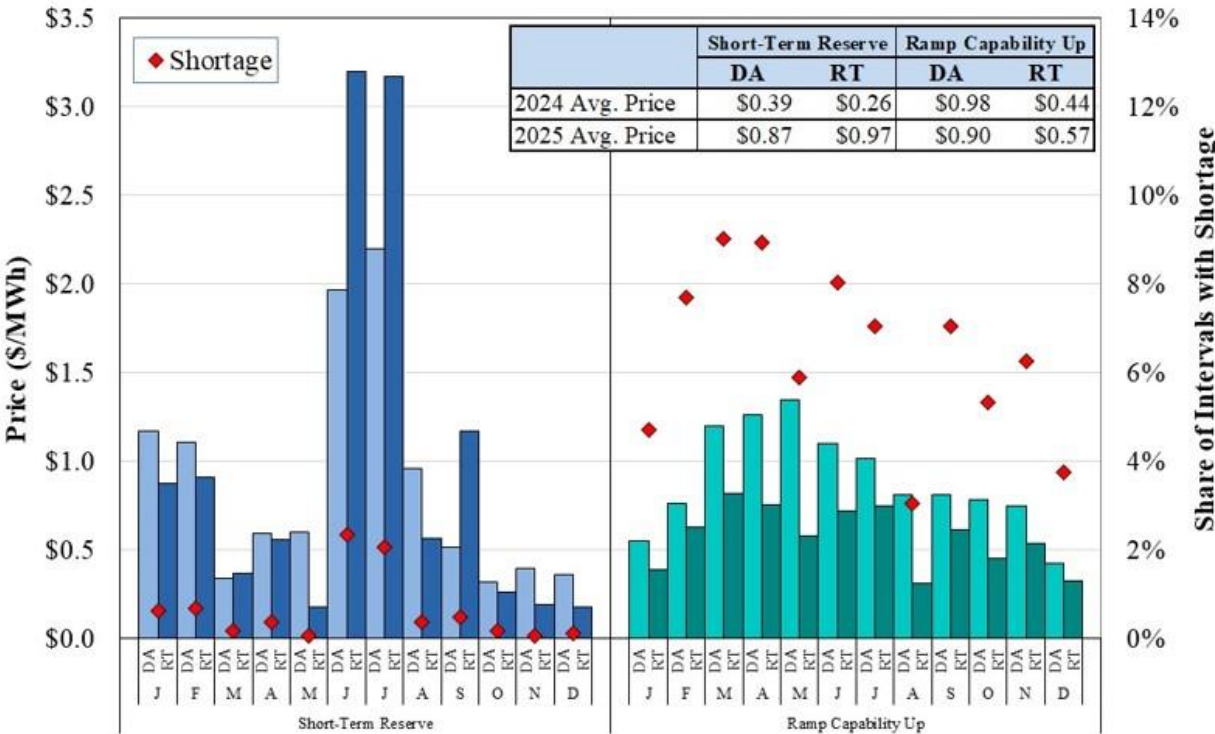
Figure A11: Contingency Reserve Offers and Scheduling
2025



Short-Term Reserves. MISO's 30-minute STR product satisfies market-wide and sub-regional requirements. MISO enforces the subregional STR requirements through Reserve Procurement Enhancement (RPE) constraints over the RDT constraint. The RPE binds when headroom on the RDT and available STR in the importing subregion are limited.

In late 2022, MISO modified the multi-step STR demand curve to reach a high step of \$500 per MWh (previously \$100 per MWh). MISO also implemented a ramp product that causes its day-ahead and real-time markets to schedule resources to maintain additional ramp-up and ramp-down capability. Although this can raise system costs slightly, it lowers the cost of satisfying system needs when the system becomes ramp constrained. Figure A12 shows the average day-ahead and real-time STR and ramp capability up product prices.

Figure A12: Short-Term Reserves and Ramp Product Prices
2025



III. FUTURE MARKET NEEDS

In this section, we illustrate the dramatic changes in MISO’s generation portfolio and their implications. We then identify the key market issues, non-market issues, and improvements that will allow MISO to navigate this transition successfully.

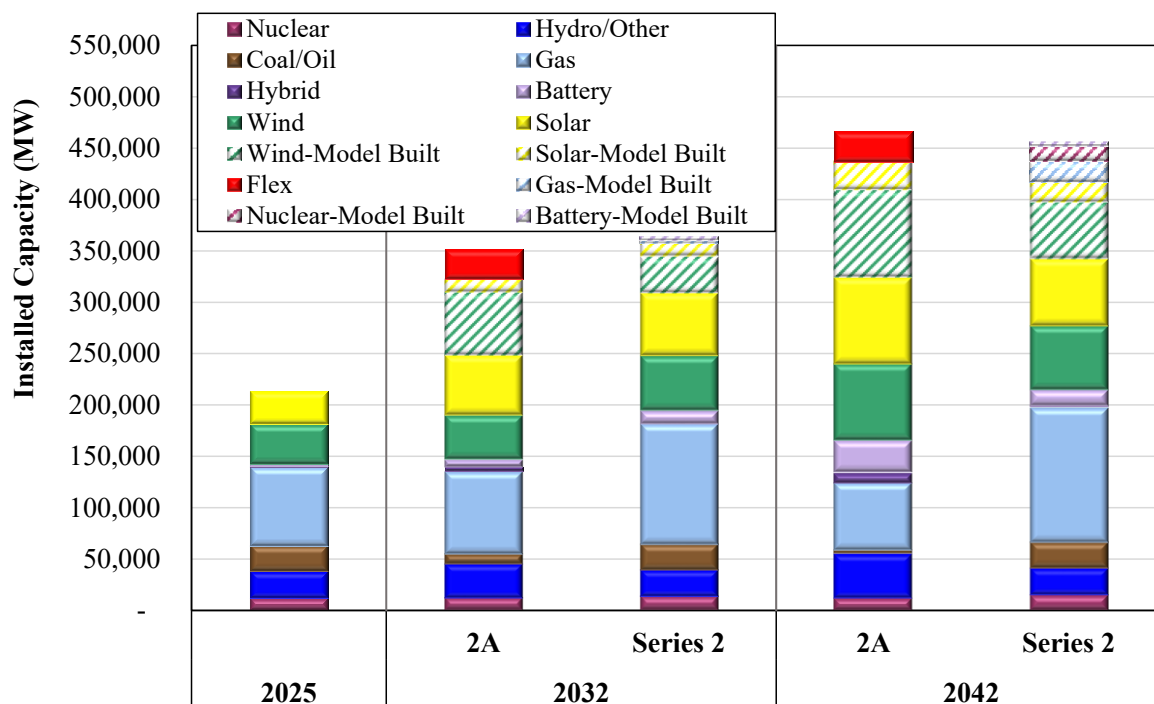
A. MISO’s Future Supply Portfolio

Figure A13: Anticipated Resource Mix

MISO’s supply portfolio is expected to change substantially over the next 20 years. MISO currently has more than 1,100 active projects in the queue, totaling nearly 220 GW and mostly comprised of renewable resources. Of these projects, one third are solar, one quarter are battery, 13 percent are wind, and 10 percent are hybrid.⁵

MISO has developed three potential Future Scenarios to bound expectations for the system’s future needs.⁶ Future 2 is an intermediate case and the primary basis for MISO’s long-range transmission planning. Figure A13 shows the resource mix in the prior Future 2A case published in 2023 and the most recent Series 2 published this year, based on updated MISO member plans and capacity expansion modeling. The stacked bars show capacity by fuel type for each year and case, beginning with the 2025 resource mix.

Figure A13: Anticipated Resource Mix: 2032 and 2042



⁵ See: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/. Data downloaded April 13, 2026.

⁶ See: https://cdn.misoenergy.org/Series1A_Future

MISO’s Series 2 Future 2 incorporates updated MISO member plans that occurred after FERC approved MISO’s DLOL capacity accreditation and Congress passed the One Big Beautiful Bill in 2025. Series 2 Future 2 indicates that even more gas-fired capacity additions are planned to come online than even the IMM 2A scenario that we had previously published.

Figure A14 and Figure A15: Share of Load Served by Wind and Solar Generation

We analyzed the cumulative share of MISO’s load served by wind and solar and how it changed over the past five years. For each hour, we determined total real-time wind and solar generation and MISO’s total real-time load, as well as regional values for the same metrics. We calculated the wind and solar share of load for each hour by dividing total wind and solar generation by total load in that hour. For the regional calculation, the numerator was wind and solar generation in MISO’s Midwest, and the denominator was the sum of MISO’s real-time load in the Central and North regions for the same hour. In Figure A14 and Figure A15, the x-axis represents the percentage of load served by wind and solar, and the y-axis shows the percentage of hours during the year when at least that share prevailed. The table reports the average, median, and maximum share of MISO’s load served by wind and solar output in 2020, 2022, and 2025.

Figure A14: Share of MISO Load Served by Wind and Solar Generation Over Time 2020–2025

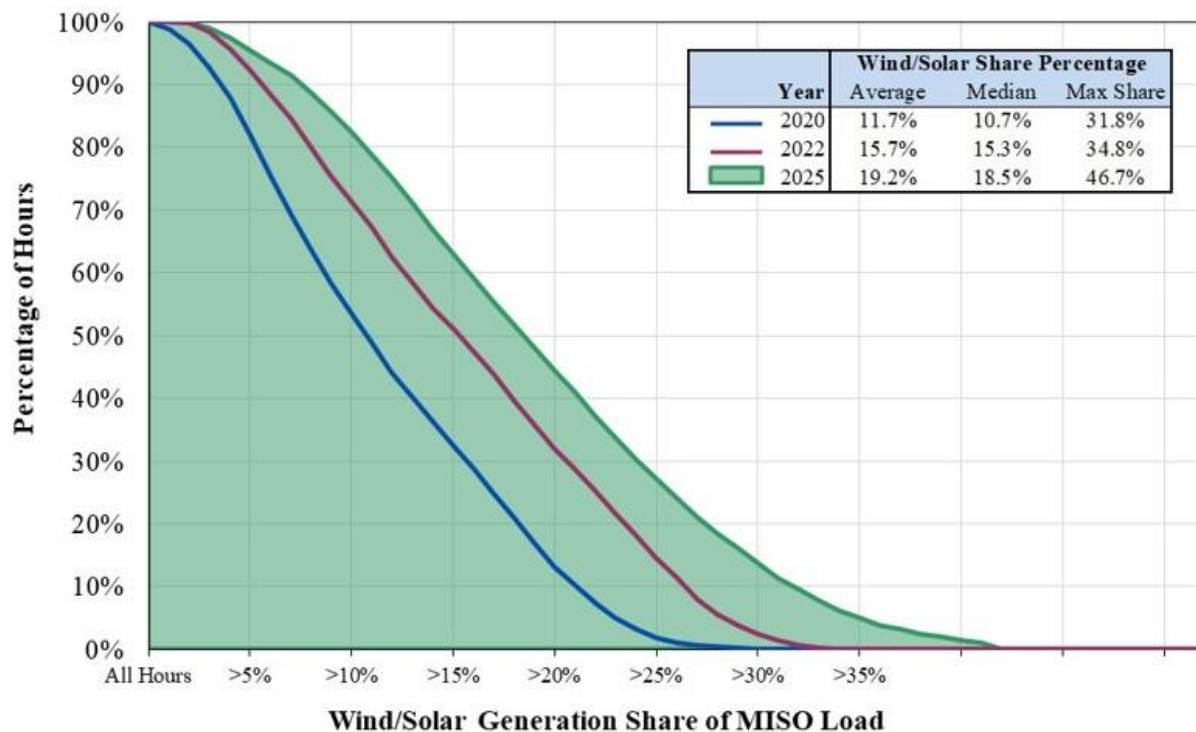


**Figure A15: Midwestern Load Share Served by Wind and Solar Generation Over Time
2020–2025**

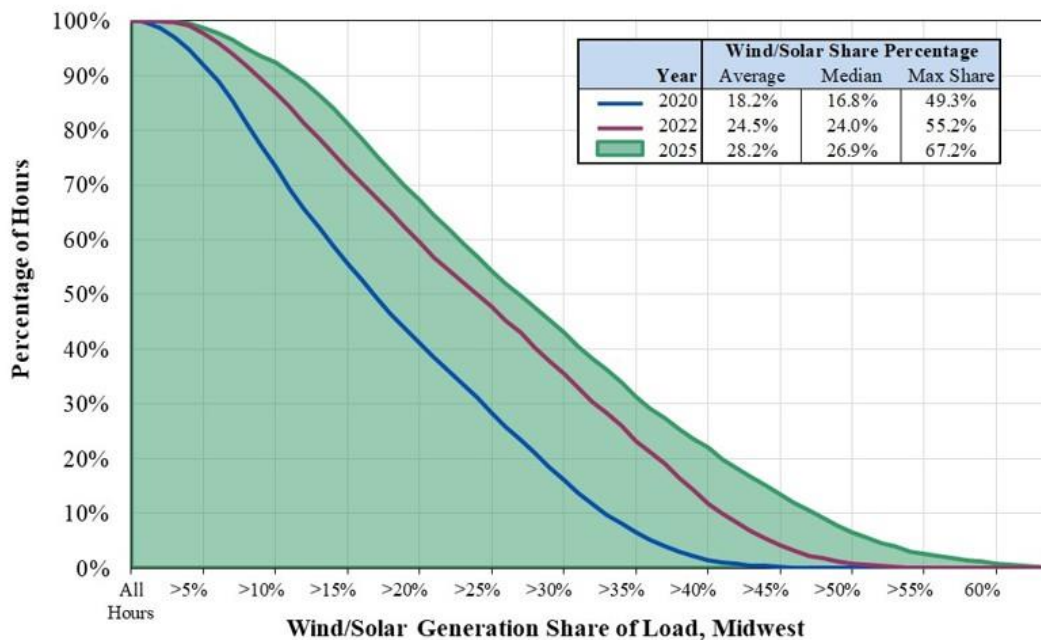


Figure A16 and Figure A17: Daily Range of Wind Generation Output

Substantial fluctuations in wind output create operational challenges. As these fluctuations grow, wind forecast errors also increase. To illustrate these challenges, we examined the daily range in wind output and the average daily wind output for January through April in Figure A16 and for May through December 2025 in Figure A17.

**Figure A16: Daily Range of Wind Generation Output
January – April 2025**

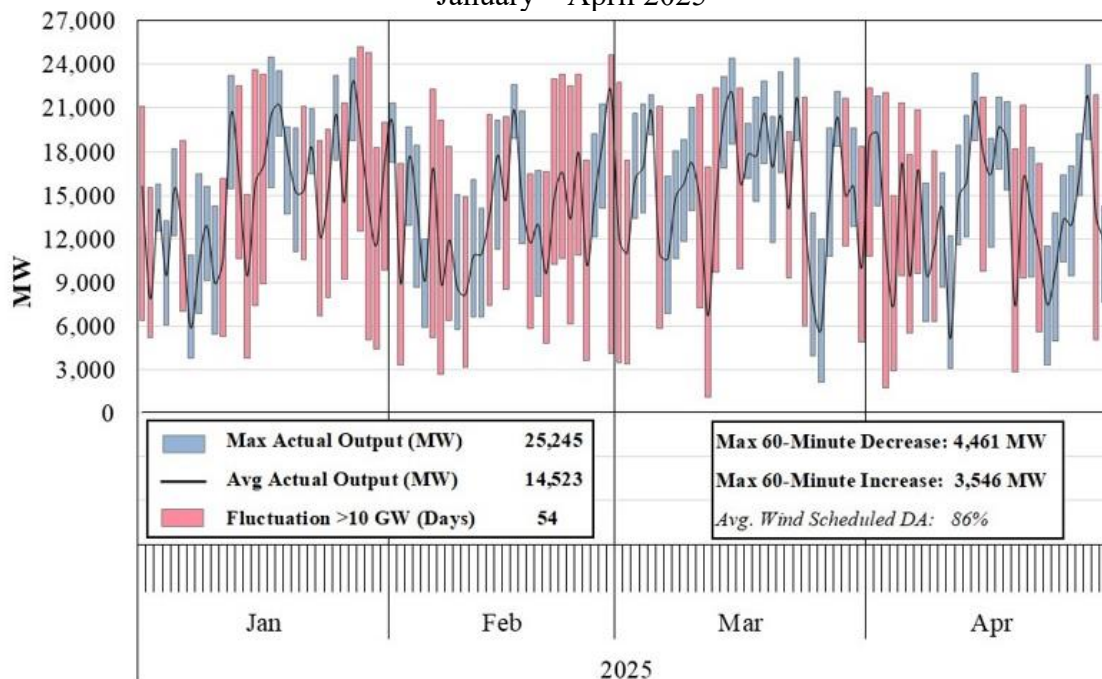
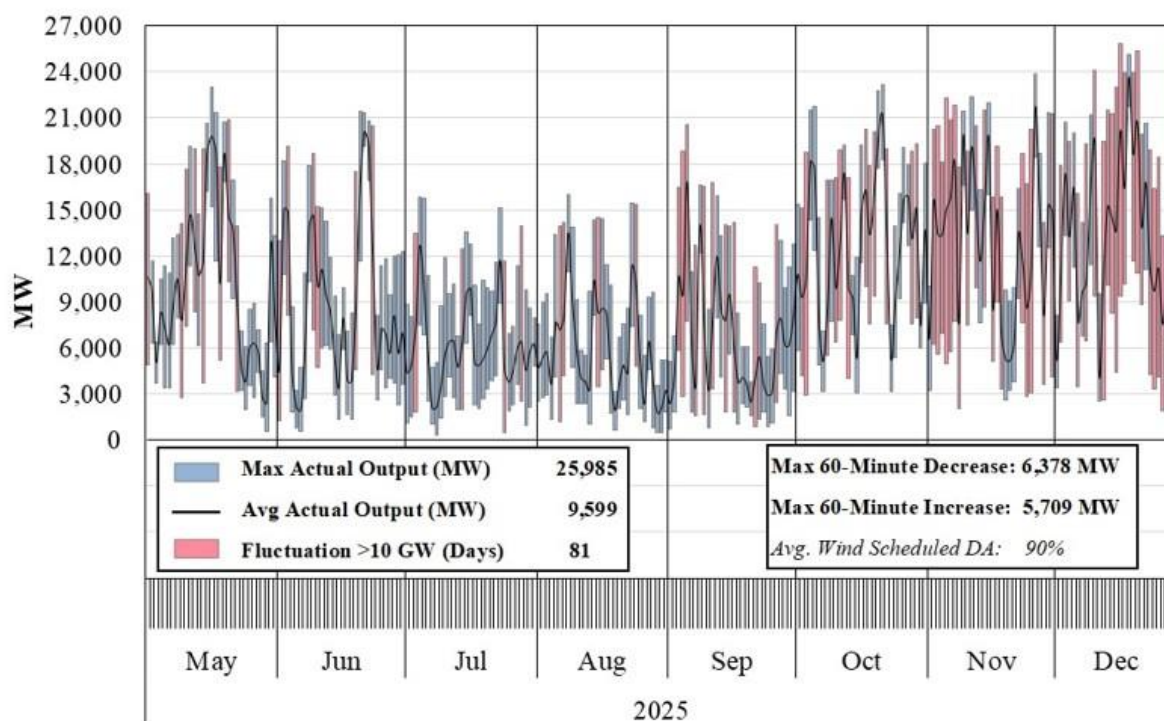


Figure A17: Daily Range of Wind Generation Output
May – December 2025



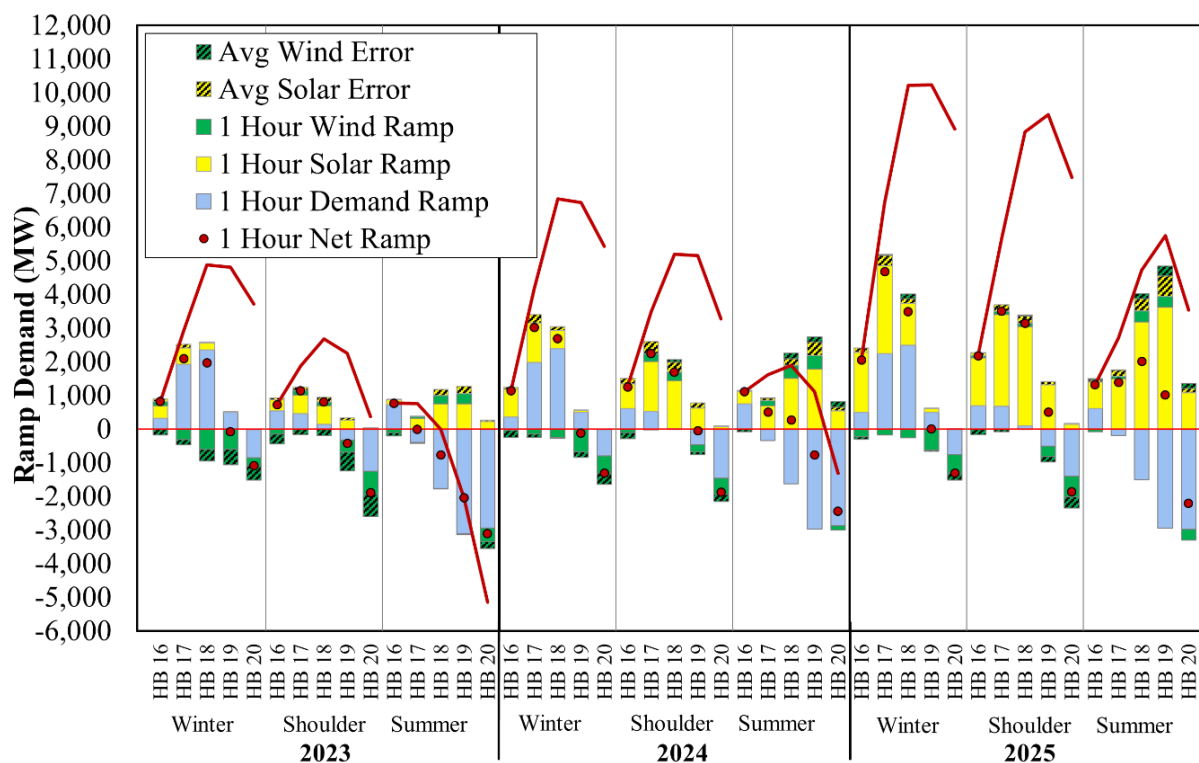
The figures show the daily range of hourly wind output (minimum to maximum) in blue and pink bars. The black line shows average daily wind production. The pink bars indicate days when wind output fluctuated by more than 10 GW.

Figure A18: Net Load Ramp

MISO's interconnection queue consists mostly of renewable resources. Solar resources are forecast to grow more rapidly than any other resource type over the next 20 years.⁷ Because of the expected timing of changes in solar output in MISO, a large quantity of these resources would likely significantly change the system's ramping needs. As solar output increases in the late morning, conventional resources will need to ramp down to balance it. Conventional resources will need to ramp up again as solar output falls sharply in the evening hours. These patterns are sharpest in the winter because MISO's load peaks in the early morning and evening.

Figure A18 shows the average and cumulative net load ramp and its contributing factors over the evening hours, by season, for the last three years. The blue bars show the average hourly change in demand. The yellow bars show the average hourly change in solar output, and the green bars show the average hourly change in wind output. The hatched yellow and green bars show solar and wind forecast errors, respectively. Positive bars represent an increase in ramp demand, and negative bars represent a decrease in ramp demand. The red dots show the average hourly net load ramp in each evening hour. The red line shows the cumulative net load ramp from hours 16 through 20.

⁷ See: *Final Draft MTEP20 Full Report*, <https://cdn.misoenergy.org/MTEP20%20Full%20Report485662.pdf>

Figure A18: Net Load Ramp in MISO

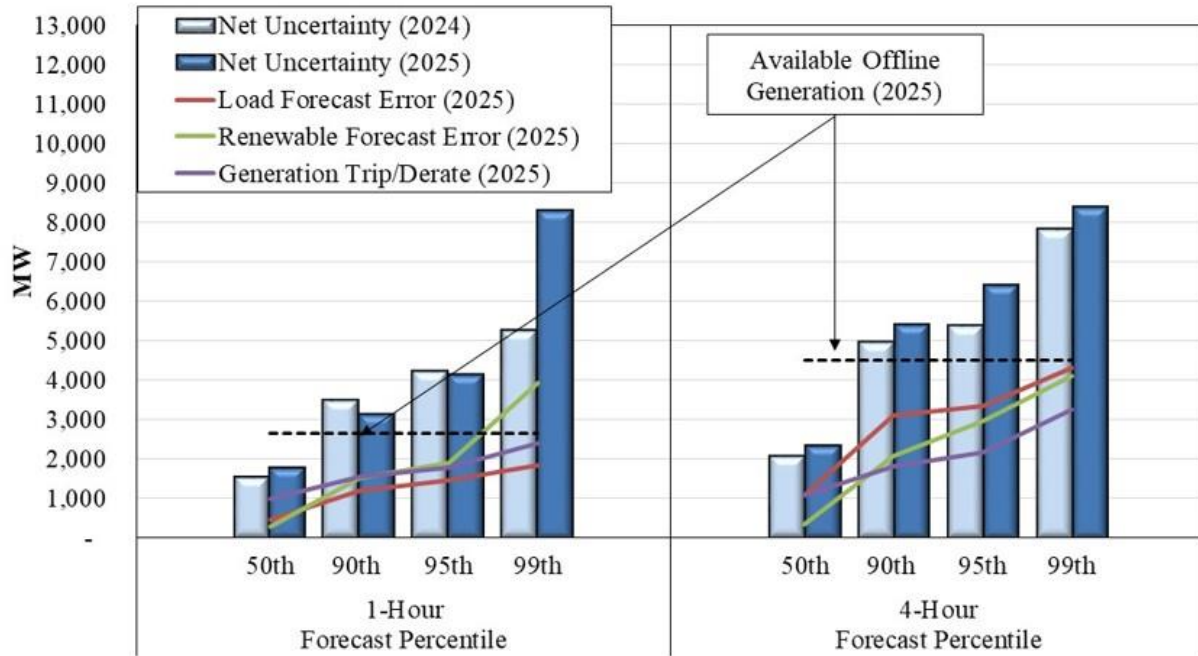
B. The Evolution of the MISO Markets to Satisfy MISO's Reliability Imperative

Figure A19: Uncertainty and MISO's Operating Requirements

The current market structure may limit MISO's ability to capture the potential benefits of high renewable growth over the next five to ten years. Renewable technologies offer clean, low marginal-cost electricity, but they also introduce greater uncertainty and lower reliability than conventional resources. As supply uncertainty increases, MISO may need to modify market systems and products to compensate and to send signals for flexible resource investment.

Figure A19 shows market-wide net uncertainty for one- and four-hour forecast leads. We calculate it from historical data on the combined effects of generation resource forced outages and forecast errors for load and renewables. We show the uncertainty the system typically faces (the 50th percentile) and the uncertainty in hours with higher uncertainty (higher percentiles). The blue bars show uncertainty one hour ahead and four hours ahead. The red, green, and purple lines show the underlying contributions of load forecast error, renewable forecast error, and generating resource trips and derates.

Figure A19: Uncertainty and MISO's Operating Requirements
January 2024 to December 2025



IV. ENERGY MARKET PERFORMANCE AND OPERATIONS

MISO's electricity markets operate in a two-settlement system, clearing in the day-ahead and real-time timeframes. The day-ahead market is financially binding, establishing one-day forward contracts for energy and ancillary services. The real-time market clears based on actual physical supply and demand and settles any deviations from day-ahead contracts at real-time prices.

A. Day-Ahead Energy Prices and Convergence with Real-Time Prices

Figure A20 and Figure A21: Day-Ahead Energy Hub Prices and SMP

Figure A20 shows average day-ahead prices during peak hours (6 a.m. to 10 p.m. on non-holiday weekdays) at six hub locations in MISO and the day-ahead System Marginal Price (SMP).

Figure A20: Day-Ahead Hub Prices and SMP
Peak Hours, 2024–2025

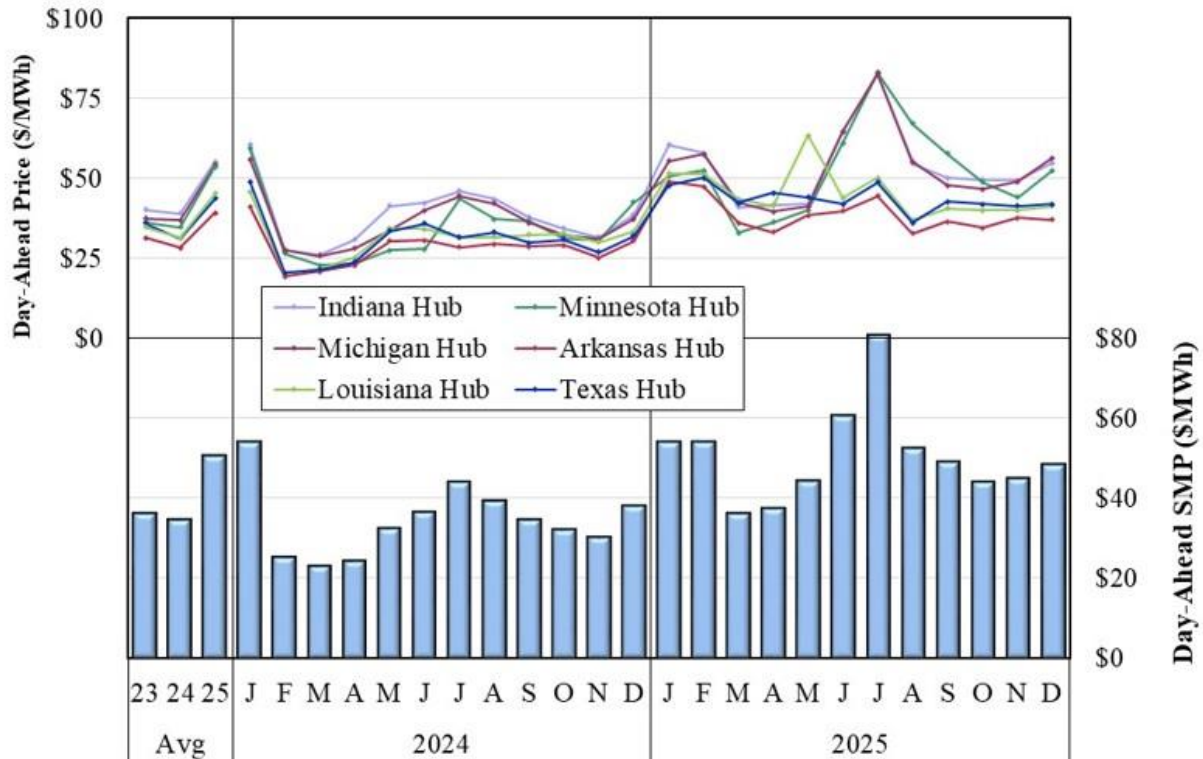
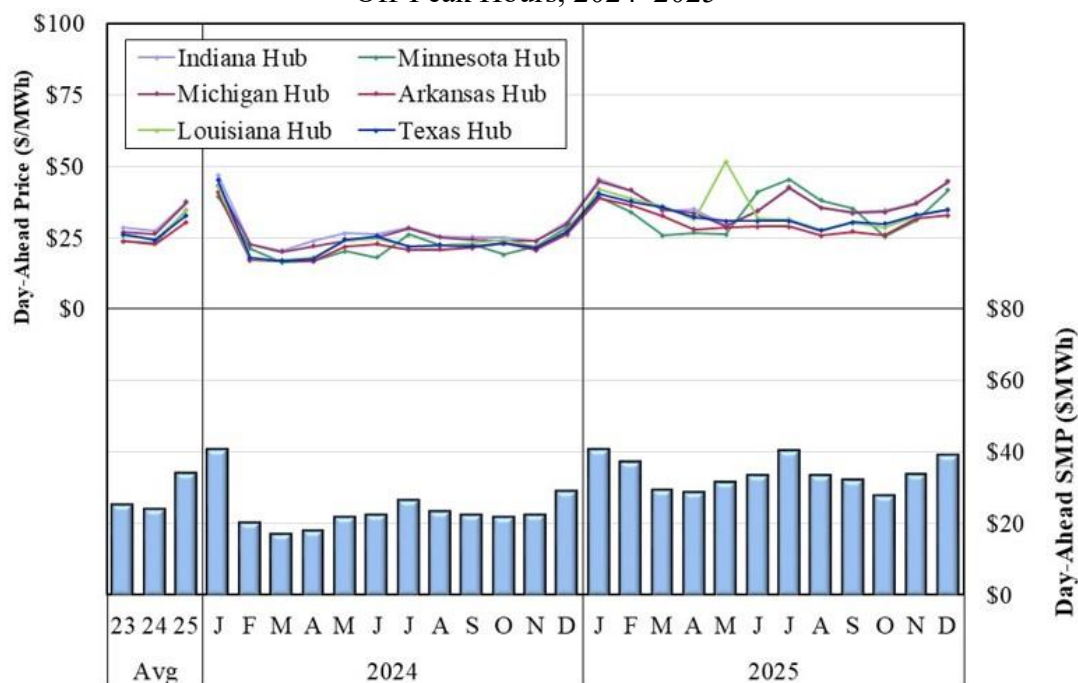


Figure A21 shows similar results for off-peak hours (10 p.m. to 6 a.m. on weekdays and all hours on weekends and holidays). Higher prices in one location than another indicate differences in congestion and loss factors between those areas.

Figure A21: Day-Ahead Hub Prices and SMP
Off-Peak Hours, 2024–2025



Convergence between day-ahead and real-time prices is a sign of a well-functioning day-ahead market, which is vital for overall market efficiency. If the day-ahead prices fail to converge with the real-time prices, then the day-ahead market is not anticipating real-time physical dispatch. This can result in: a) generating resources not being committed efficiently because the day-ahead market commits most resources; b) substantial effects on consumers and generators because most settlements occur through the day-ahead market; and c) payments to Financial Transmission Rights (FTR) holders that do not reflect true transmission congestion on the network, ultimately distorting future FTR prices and revenues.

Participants' day-ahead market bids and offers should reflect their expectations of the real-time market for the following day. However, several factors can cause real-time prices to be much higher or lower than day-ahead market prices. Although a well-performing market may not produce price convergence every hour, prices should converge over the longer term.

Figure A22 to Figure A27: Day-Ahead and Real-Time Prices

The next seven figures summarize price convergence in the MISO markets by showing monthly average day-ahead and real-time prices at representative MISO locations, along with the average RSG costs allocated per MWh.⁸ The table below the figures shows the average difference between day-ahead and real-time prices, including and excluding RSG charges. MISO assesses real-time RSG to deviations from day-ahead schedules that settle through the real-time market, including net virtual supply. Because real-time RSG charges are generally much higher than day-ahead charges, they should lead to modest day-ahead price premiums.

⁸ The rate is the Day-Ahead Deviation and Headroom Charge (DDC) Rate, which excludes the location-specific Congestion Management Charge (CMC) Rate and Pass 2 RSG.

Figure A22: Day-Ahead and Real-Time Prices
2024–2025: Indiana Hub

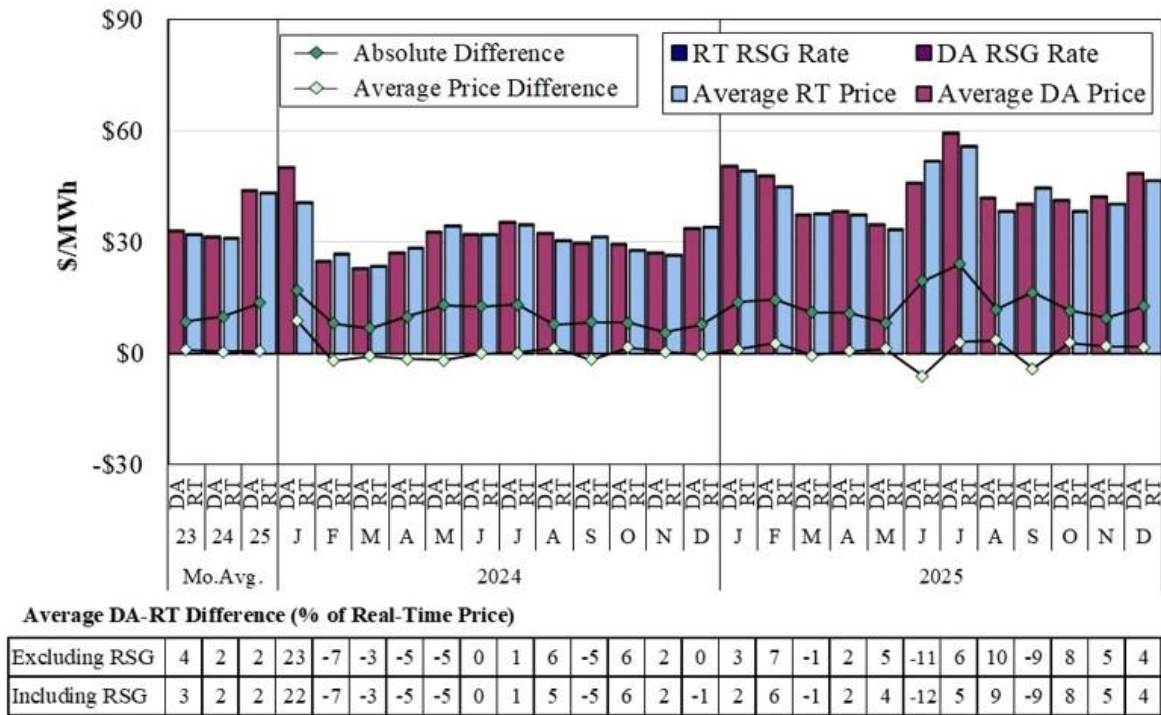


Figure A23: Day-Ahead and Real-Time Prices
2024–2025: Michigan Hub

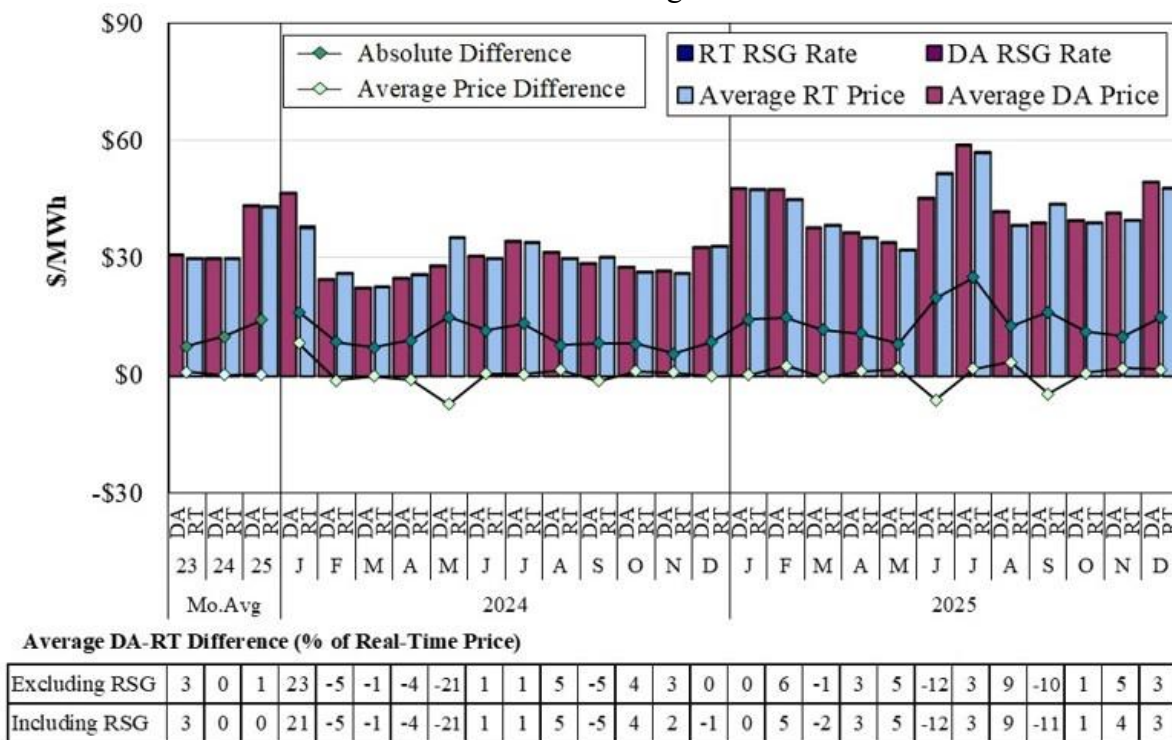


Figure A24: Day-Ahead and Real-Time Prices
2024–2025: Minnesota Hub

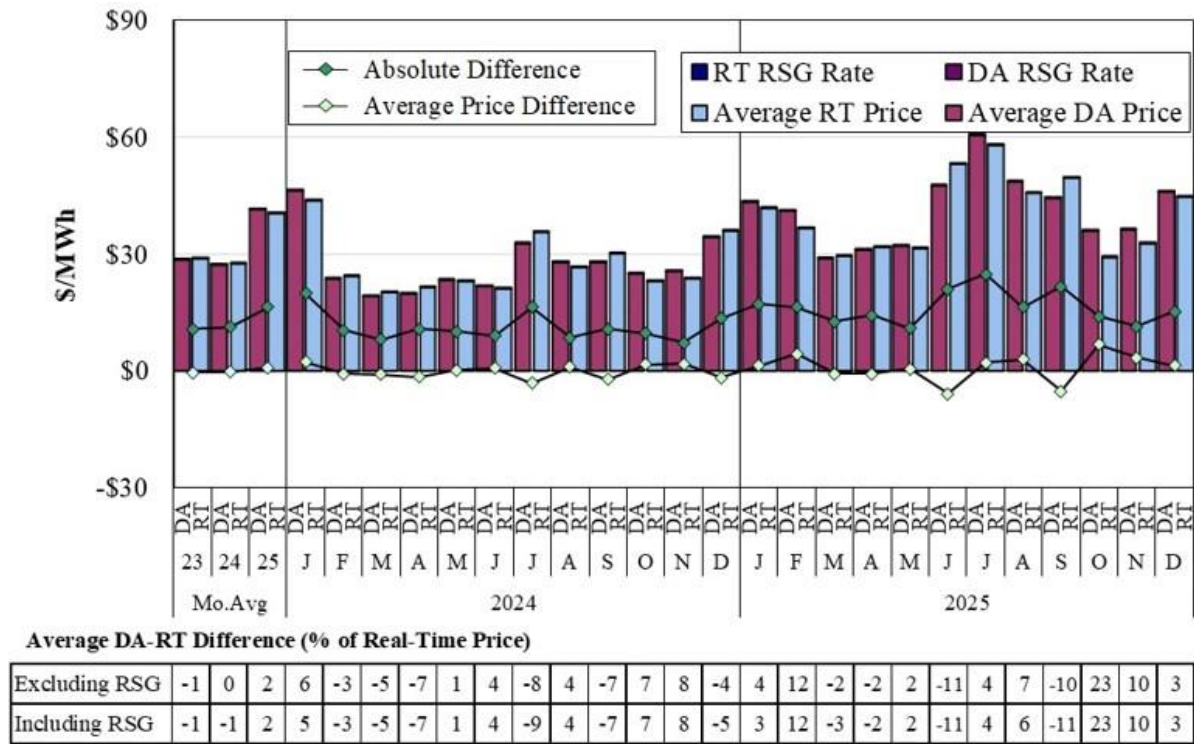


Figure A25: Day-Ahead and Real-Time Prices
2024–2025: Arkansas Hub

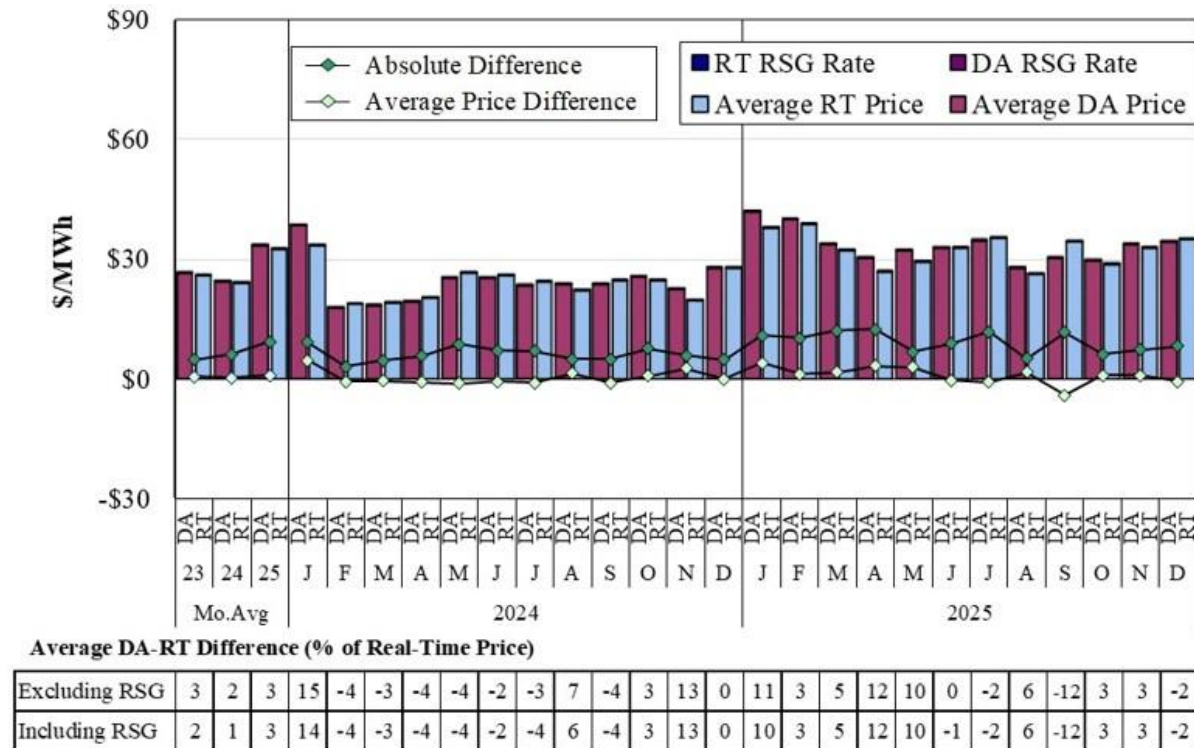


Figure A26: Day-Ahead and Real-Time Prices
2024–2025: Louisiana Hub

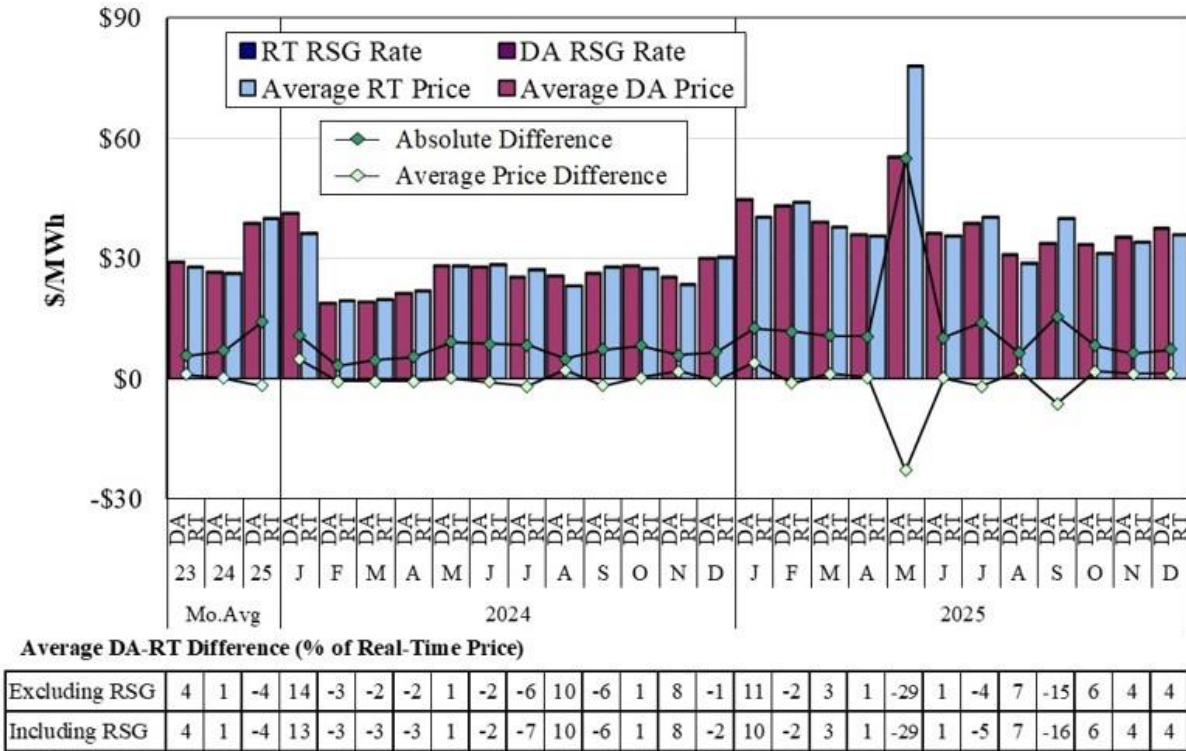


Figure A27: Day-Ahead and Real-Time Prices
2024–2025: Texas Hub

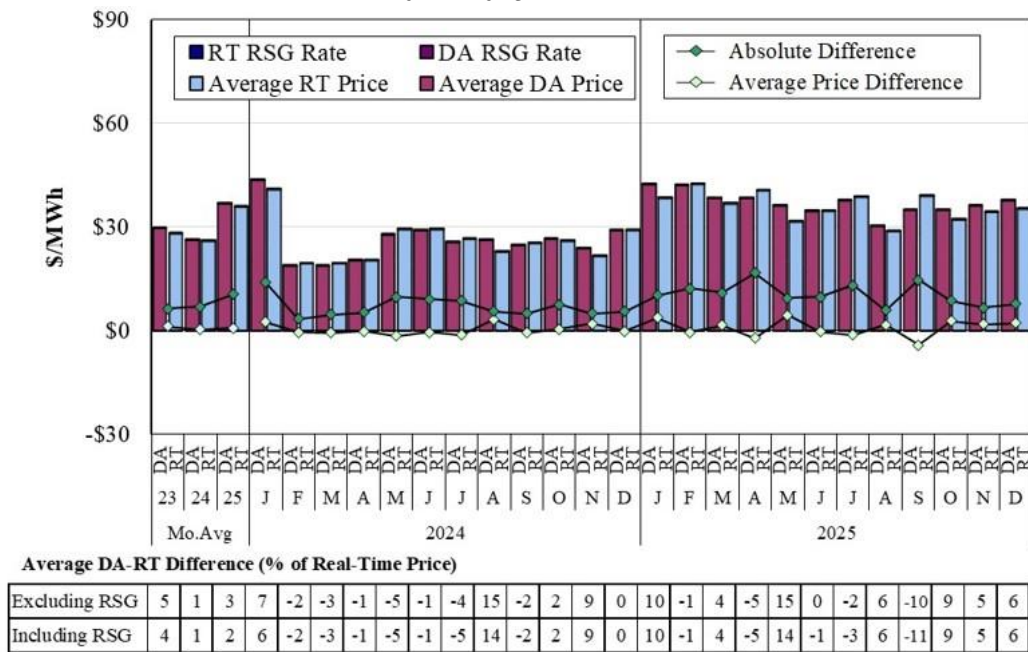
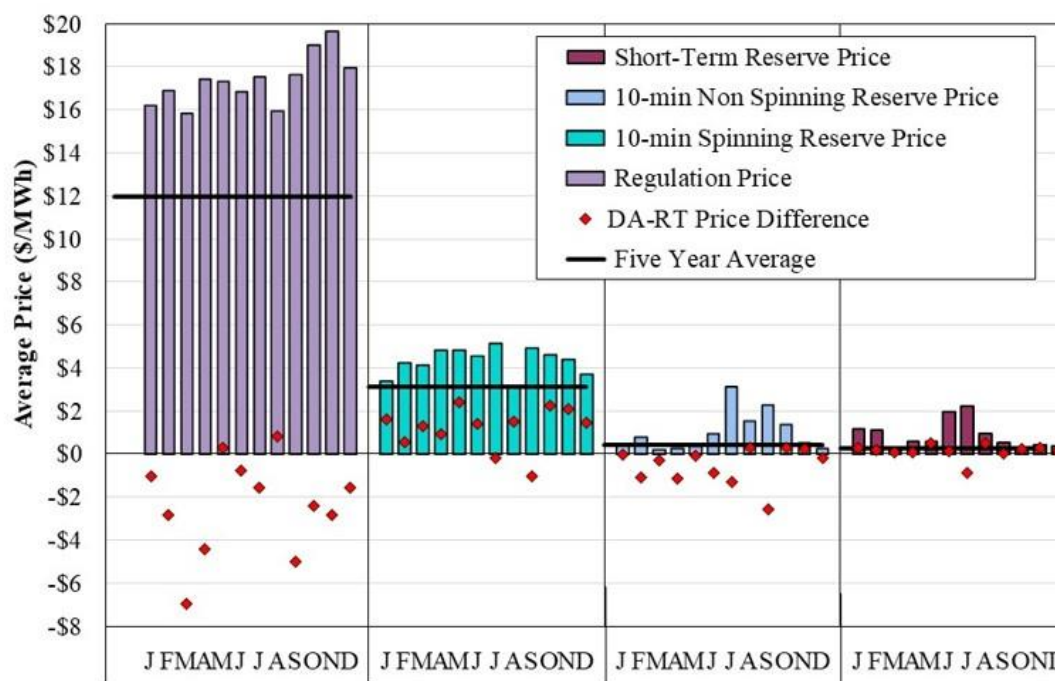


Figure A28: Day-Ahead Ancillary Services Prices and Price Convergence

Price convergence is also important in the ancillary services markets, which are jointly optimized with the energy markets. Figure A28 shows monthly average day-ahead clearing prices for each ancillary services product, along with day-ahead and real-time price differences.

Figure A28: Day-Ahead Ancillary Services Prices and Price Convergence
2025



B. Day-Ahead Load Scheduling

Load scheduling, Net Scheduled Interchange (NSI), and virtual trading in the day-ahead market play an important role in market efficiency by promoting optimal commitments and improved price convergence between the day-ahead and real-time markets. Day-ahead load is the sum of physical load and virtual load. Physical load includes cleared price-sensitive load and fixed load. Price-sensitive load is scheduled (i.e., cleared) if the day-ahead price is equal to or less than the load bid. A fixed-load schedule does not include a bid price, which indicates a desire to be scheduled regardless of the day-ahead price.

Virtual trading in the day-ahead market consists of energy purchases or sales that are not associated with physical load or resources. Like price-sensitive load, virtual load clears if the day-ahead price is equal to or less than the virtual load bid. Net day-ahead load equals cleared physical load, plus cleared virtual load minus cleared virtual supply, plus NSI. Differences between net day-ahead load and real-time load are important because they can undermine efficient generator commitment patterns and raise RSG costs.

When net day-ahead load is significantly less than real-time load, particularly in the day's peak-load hour, MISO frequently needs to commit peaking resources after the day-ahead market to satisfy real-time demand. This can contribute to suboptimal real-time pricing and inefficient

outcomes when peaking units committed in real time displace lower-cost generation scheduled in the day-ahead market. Because these peaking units frequently do not set real-time prices, even though they are more expensive than other resources, they dilute the economic feedback and incentive to schedule more fully in the day-ahead market.

Additionally, significant supply increases after the day-ahead market can lower real-time prices and incentivize participants to schedule net load at less than 100 percent. The most common sources of increased real-time supply are:

- Supplemental commitments made by MISO for reliability after the day-ahead market;
- Self-commitments made by market participants after the day-ahead market;
- Under-scheduled wind and solar output in the day-ahead market; and
- Real-time net imports above day-ahead schedules.

Figure A29 to Figure A31: Day-Ahead Scheduled Versus Actual Loads

Figure A29 compares monthly average day-ahead scheduled load with average real-time load to show net day-ahead load-scheduling patterns. The figure shows only the daily peak hours, when under-scheduling is most likely to require MISO to commit additional units. The table below the figure shows average scheduling levels in all hours and in the peak hour. Figure A30 and Figure A31 show peak-hour scheduling separately by region.

Figure A29: Day-Ahead Scheduled Versus Actual Loads
2024–2025, Daily Peak Hour

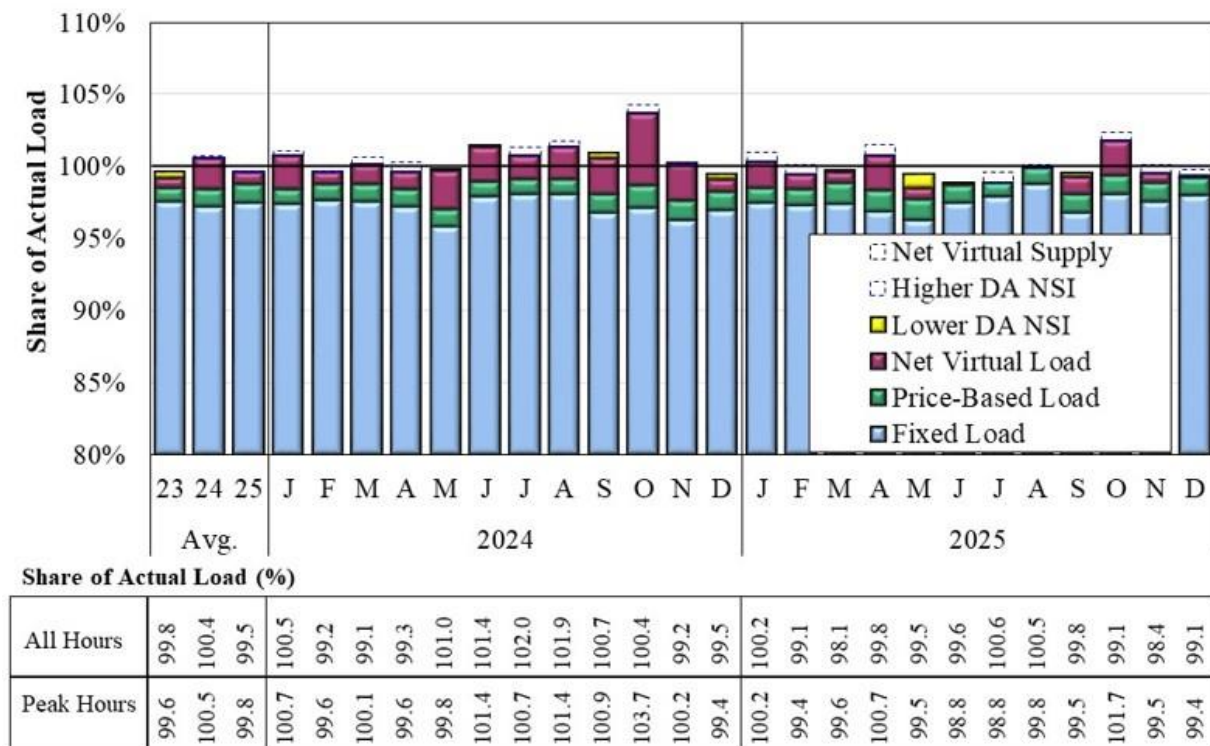


Figure A30: MISO Midwest Day-Ahead Scheduled Versus Actual Loads
2024–2025, Daily Peak Hour

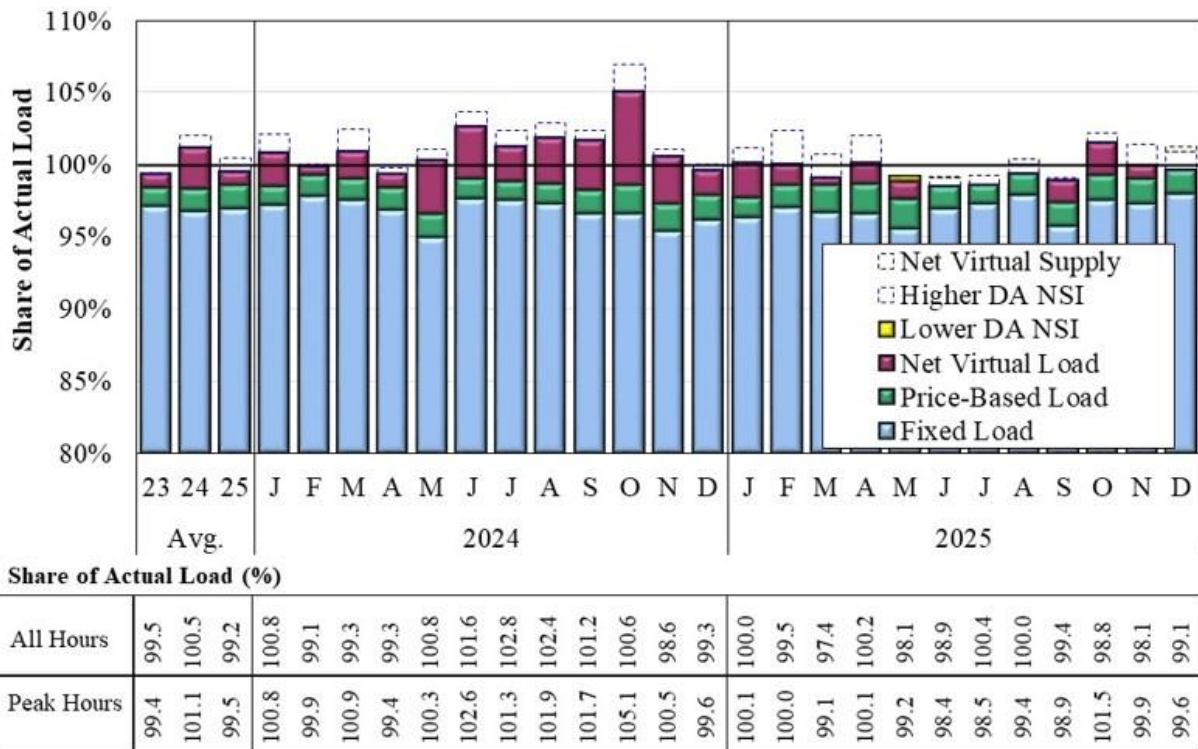
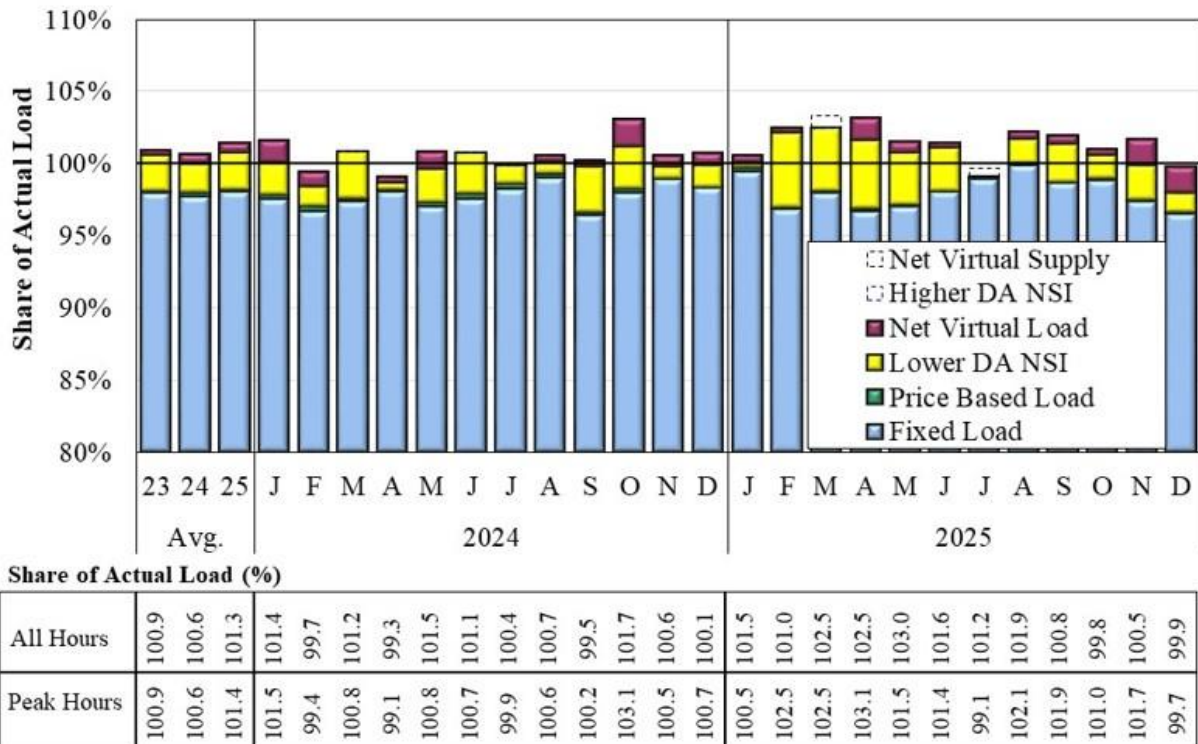


Figure A31: MISO South Day-Ahead Scheduled Versus Actual Loads
2024–2025, Daily Peak Hour

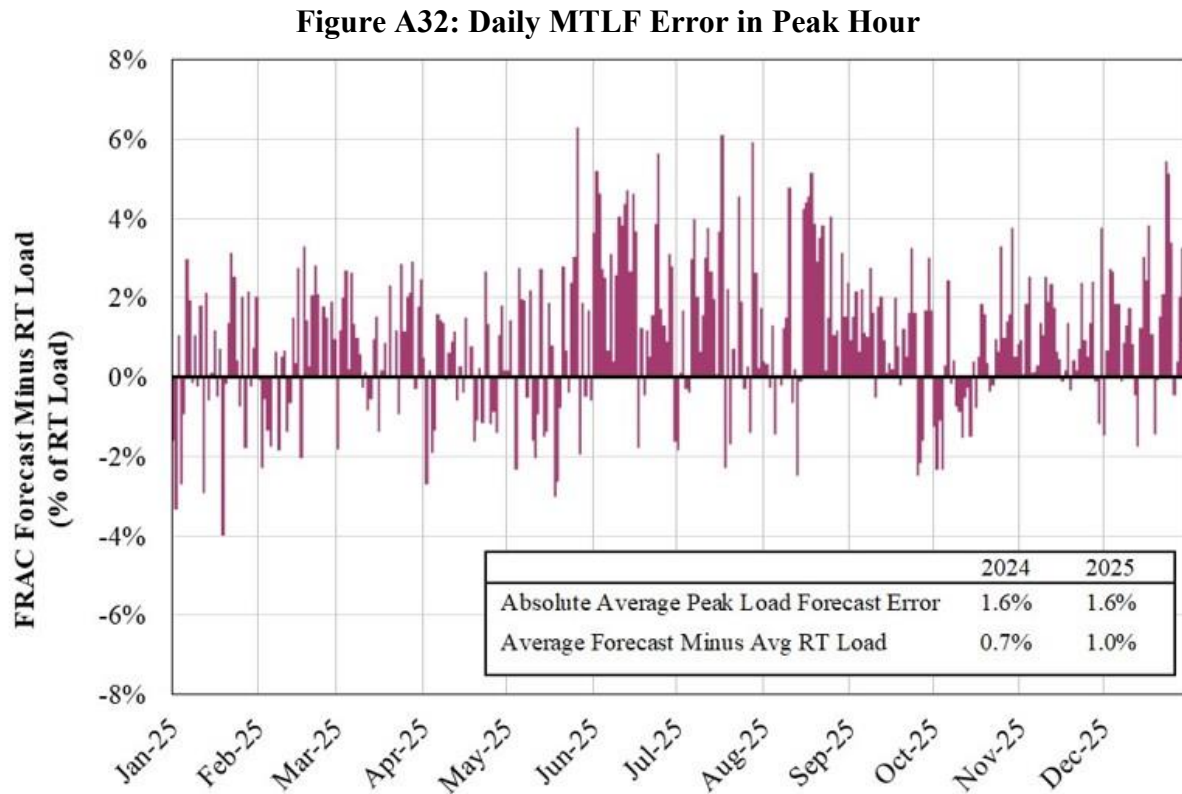


C. Load Forecasting

Load forecasting is a key element of an efficient forward commitment process. Accuracy of the Mid-Term Load Forecast (MTLF) is important because it is used by the Forward Reliability Assessment Commitment (FRAC) process.

Figure A32: Daily MTLF Error in Peak Hour

Figure A32 shows the MTLF error as a percent of actual load in the peak hour of each day.



D. Hourly Day-Ahead Scheduling

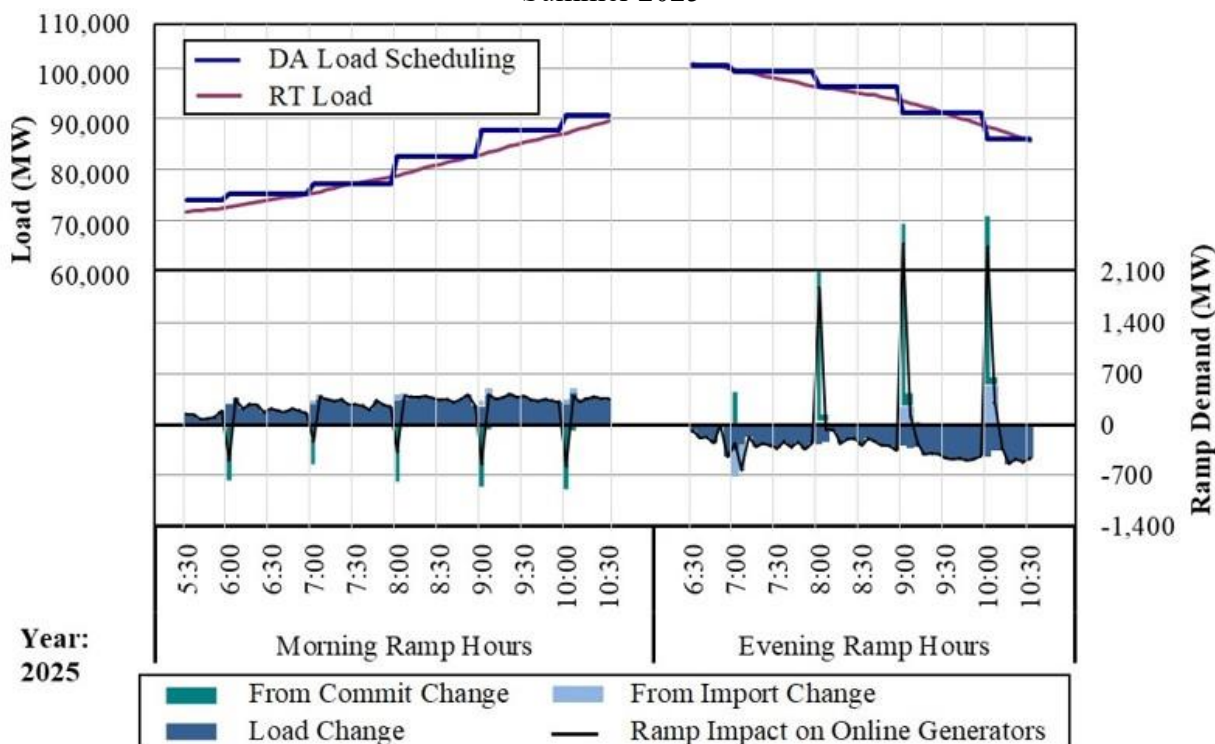
The day-ahead energy and ancillary services markets clear on an hourly basis. As a result, all day-ahead scheduled ramp demands coming into the real-time market, including unit commitments, de-commitments, and changes to physical schedules are concentrated at the top of each hour.

MISO has several options to manage the impact of top-of-the-hour changes in real time, including staggering unit commitments (which can increase RSG payments) or proactively using load offsets to reduce ramp impacts. Nonetheless, the current hourly resolution of the day-ahead market can create substantial real-time ramp demands and significant real-time price volatility.

Figure A32: Ramp Demand Impact of Hourly Day-Ahead Market

Figure A32 shows the implied generation ramp demand attributable to day-ahead commitments and physical schedules relative to real-time load changes. When the sum of these changes is negative, online generators must ramp up in real time to balance the market. When the sum is positive, generators must ramp down in real time. Ramp demand is greatest at the top of the hour because of day-ahead commitment changes and changes in NSI.

Figure A32: Ramp Demand Impact of Hourly Day-Ahead Market
Summer 2025



E. Virtual Transactions in the Day-Ahead Market

Virtual trading provides essential liquidity to the day-ahead market because it accounts for a large share of the marginal price sensitivity needed to establish efficient day-ahead prices. Virtual transactions scheduled in the day-ahead market settle against real-time prices. Virtual trading is profitable when a trader buys low and sells high. For virtual demand bids, this occurs when the real-time energy price is higher than the day-ahead price. For virtual supply offers, this occurs when the day-ahead energy price is higher than the real-time price.

Accordingly, if virtual traders expect day-ahead prices to exceed real-time prices, they sell virtual supply forward and buy it back financially in the real-time market. If they forecast higher real-time prices, they buy virtual load. This trading is a primary means of arbitraging prices

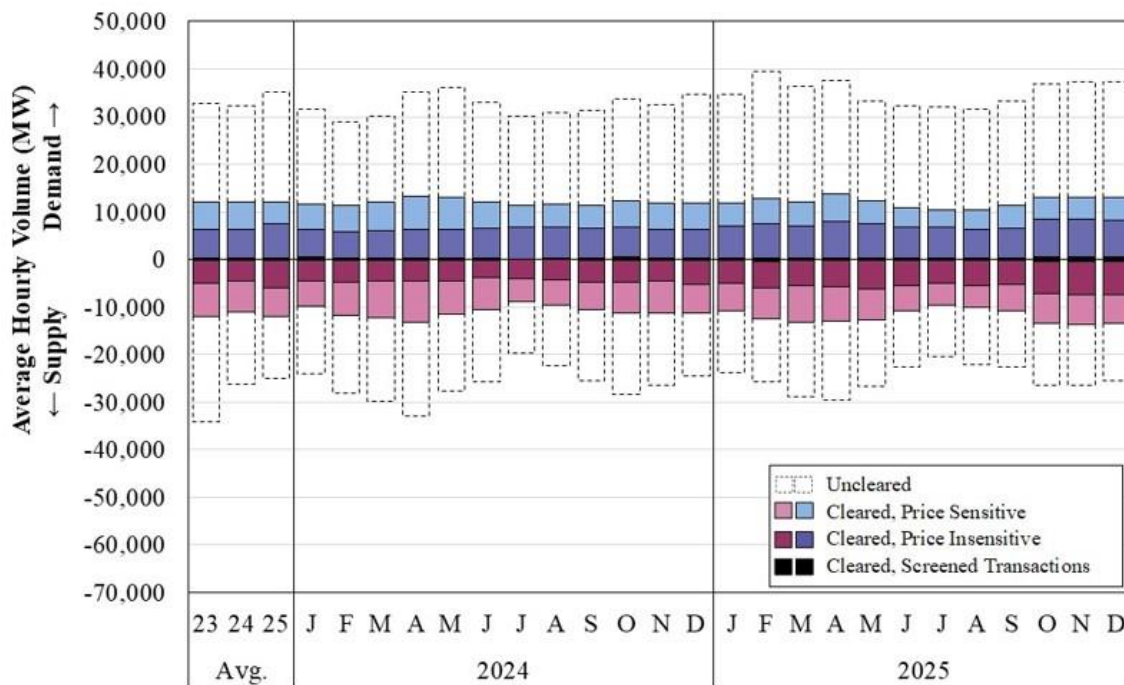
between the two markets. Numerous empirical studies show that this arbitrage converges day-ahead and real-time prices, thereby improving market efficiency and mitigating market power.⁹

Large sustained profits from virtual trading may indicate day-ahead modeling inconsistencies, while large losses may indicate an attempt to manipulate day-ahead prices. Attempts to create artificial congestion or other day-ahead price movements using a virtual position would cause prices to diverge from real-time prices. That divergence would make the virtual position unprofitable. We monitor for such behavior and use mitigation authority to restrict virtual activity when appropriate.

Figure A33 and Figure A34: Day-Ahead Virtual Transaction Volumes

Figure A33 shows the average offered and cleared amounts of virtual supply and demand in the day-ahead market from 2024 to 2025. Figure A34 separates the 2025 volumes by region. Dashed areas at the top and bottom of the solid bars show virtual bids and offers that did not clear. These bids and offers were not economic at the prevailing day-ahead market prices (supply offered above the clearing price and demand bid below the clearing price).

**Figure A33: Day-Ahead Virtual Transaction Volumes
2024–2025**

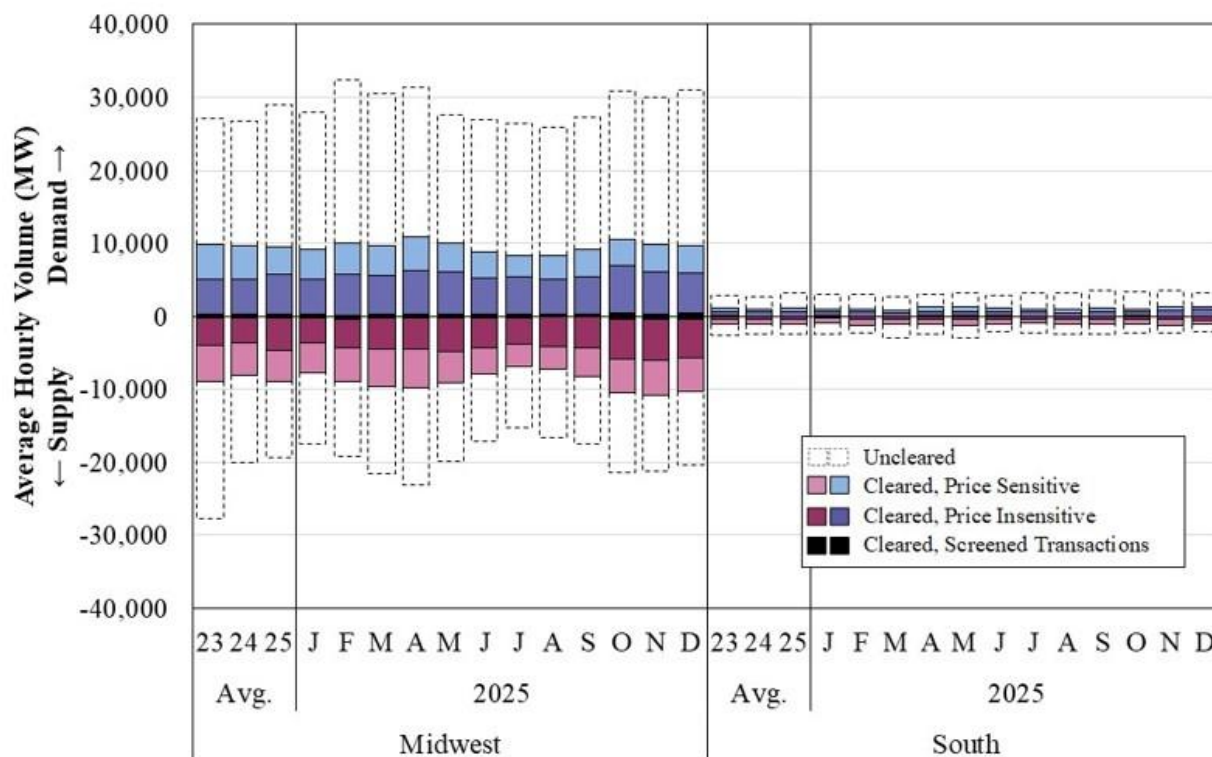


⁹ Chaves, Jose Pablo and Yannick Perez. 2010. Virtual Bidding: A Mechanism to Mitigate Market Power in Electricity Markets: Some Evidence from New York Market, Working Paper.

Hadsell, Lester, and Hany A. Shawky. 2007. One-Day Forward Premiums and the Impact of Virtual Bidding on the New York Wholesale Electricity Market Using Hourly Data, *Journal of Futures Markets* 27(11).

Mercadal, Ignacia. 2015. Dynamic Competition and Arbitrage in Electricity Markets: The Role of Financial Players. Working Paper, University of Chicago, October 2015.

Figure A34: Day-Ahead Virtual Transaction Volumes by Region
2025



The figures above distinguish between price-sensitive and price-insensitive bids. Price-insensitive bids are very likely to clear (supply offers priced well below the expected real-time price and demand bids priced well above the expected real-time price). In these figures, bids and offers submitted at more than \$20 above or below the expected real-time price are considered price insensitive. A subset of these transactions contributed materially to an unexpected difference in congestion between the day-ahead and real-time markets, warranting further investigation. The figures label these volumes ‘Screened Transactions’.

Figure A35 to Figure A38: Virtual Transaction Volumes by Participant Type

The next figures show day-ahead virtual transactions by participant type because participants engage in virtual trading for different purposes. Physical participants are more likely to engage in virtual trading to hedge or manage risks associated with their physical positions. Financial participants are more likely to engage in speculative trading to arbitrage differences between day-ahead and real-time markets. This class of trading improves market performance. Figure A35 shows the same results and additionally distinguishes between physical participants that own generation or serve load, including their subsidiaries and affiliates, and financial-only participants. Figure A36 and Figure A37 show the same values by region, and Figure A38 shows these values by location type.

Figure A35: Virtual Transaction Volumes by Participant Type
2025

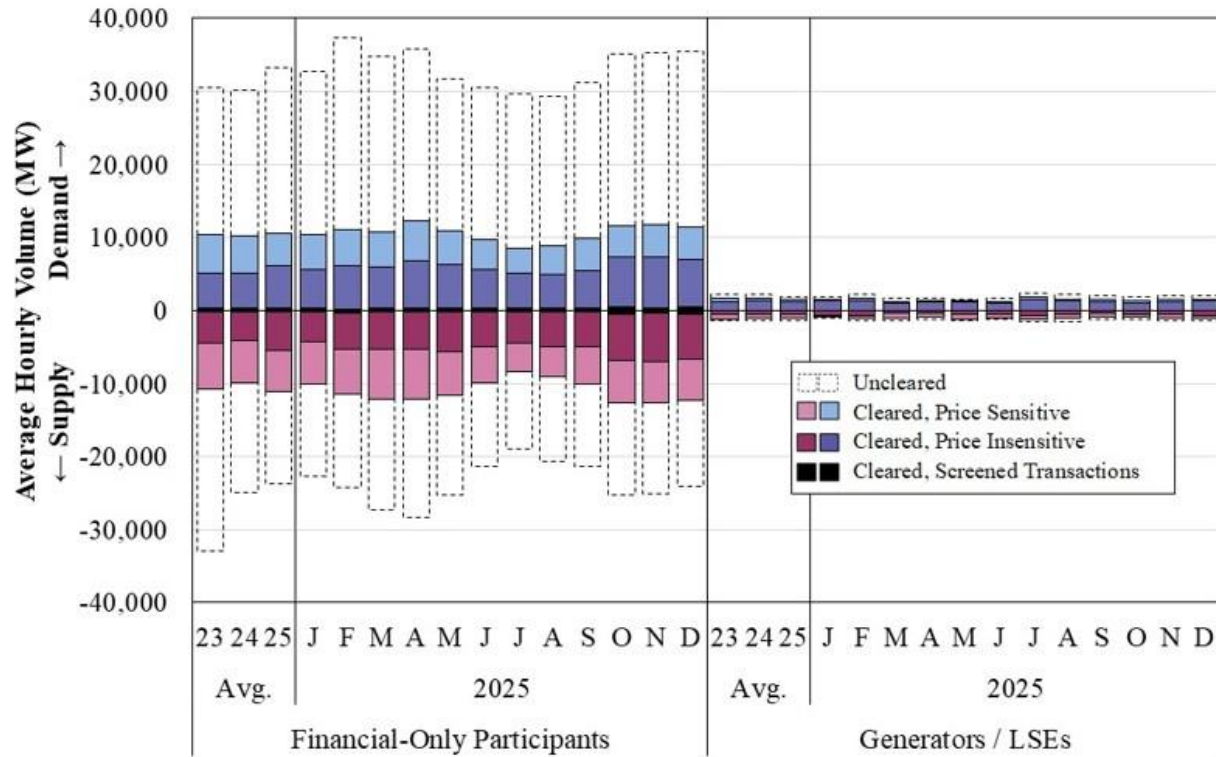


Figure A36: Virtual Transaction Volumes by Participant Type
MISO Midwest, 2025

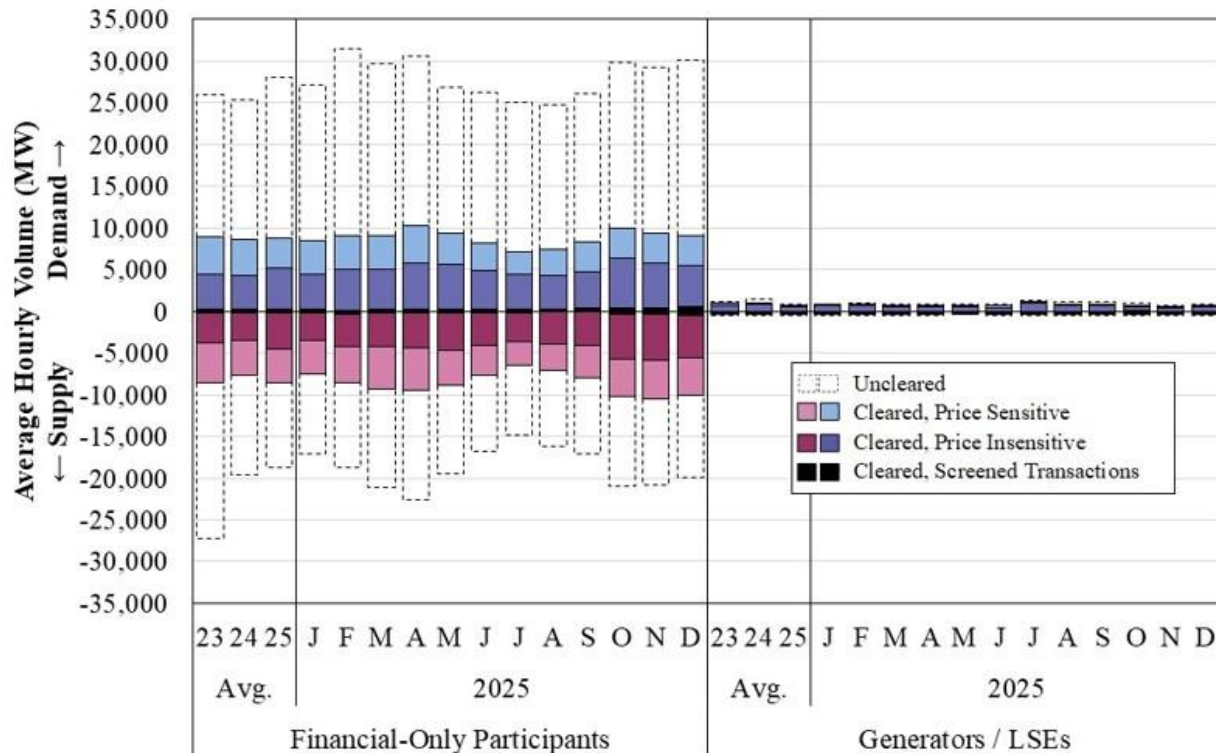


Figure A37: Virtual Transaction Volumes by Participant Type
MISO South, 2025

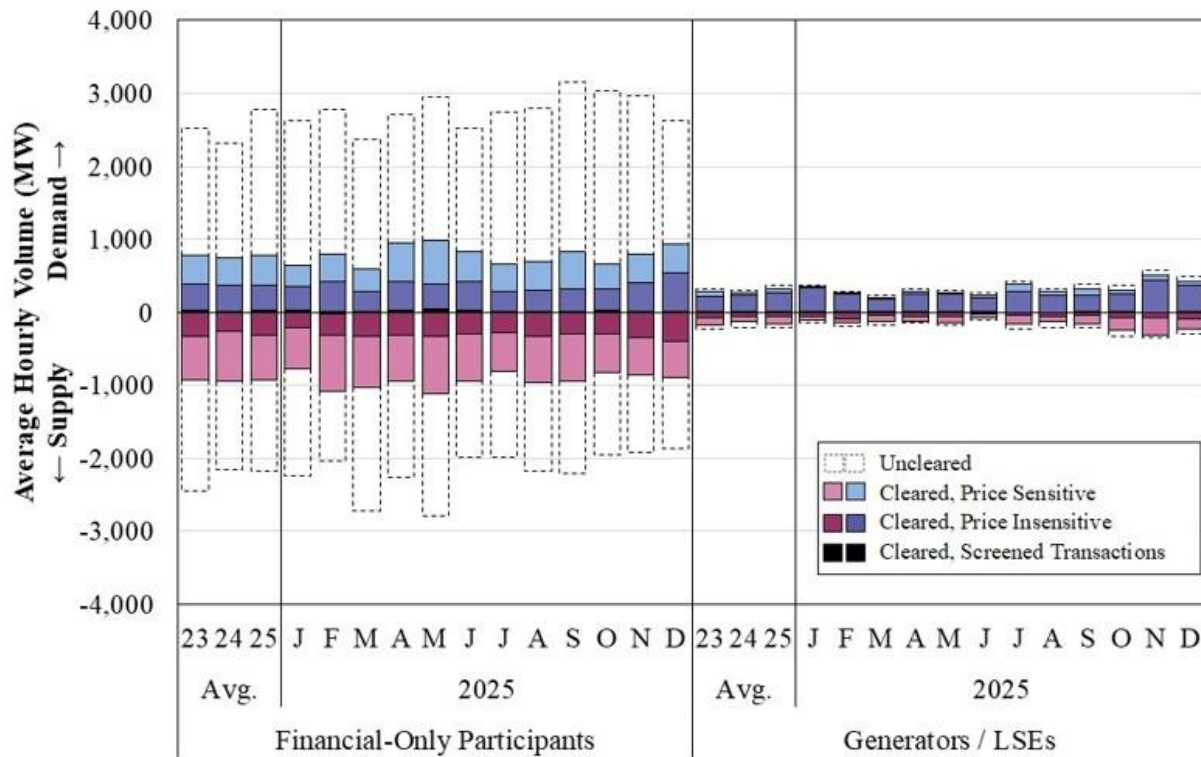


Figure A38: Virtual Transaction Volumes by Participant Type and Location
2023–2025

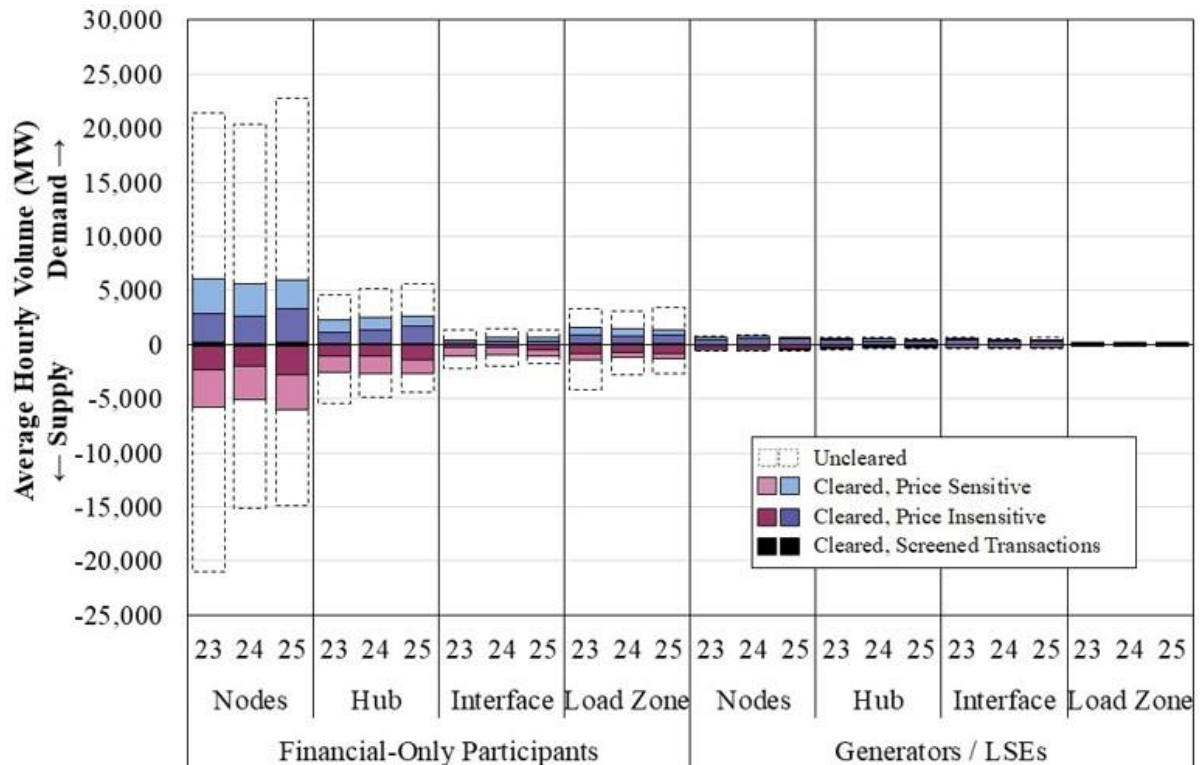


Figure A38 above further disaggregates transaction volumes by participant type and four location types: hub locations, load zones, generator nodes, and interfaces. Because hubs, interfaces, and load zones aggregate many electrical nodes, they are less prone to congestion-related price spikes than generator locations.

Figure A39: Matched Price-Insensitive Virtual Transactions

Figure A39 shows the monthly average of cleared virtual transactions considered price insensitive. Price-insensitive bids and offers are priced to make them very likely to clear. The figure also shows the subset of “matched” transactions, which occur when a participant clears both insensitive supply and insensitive demand in a particular hour.

Participants most often place price-insensitive transactions for two reasons:

- A participant seeks an energy-neutral position relative to a particular constraint. This allows the participant to arbitrage differences in congestion and losses between locations.
- A participant seeks to balance their portfolio. MISO assesses RSG and Day-Ahead Deviation and Headroom Charges (DDC) to virtual participants based on net virtual supply, so participants can avoid such charges by clearing equal amounts of supply and demand.

Figure A39: Matched Price-Insensitive Virtual Transactions
2024–2025

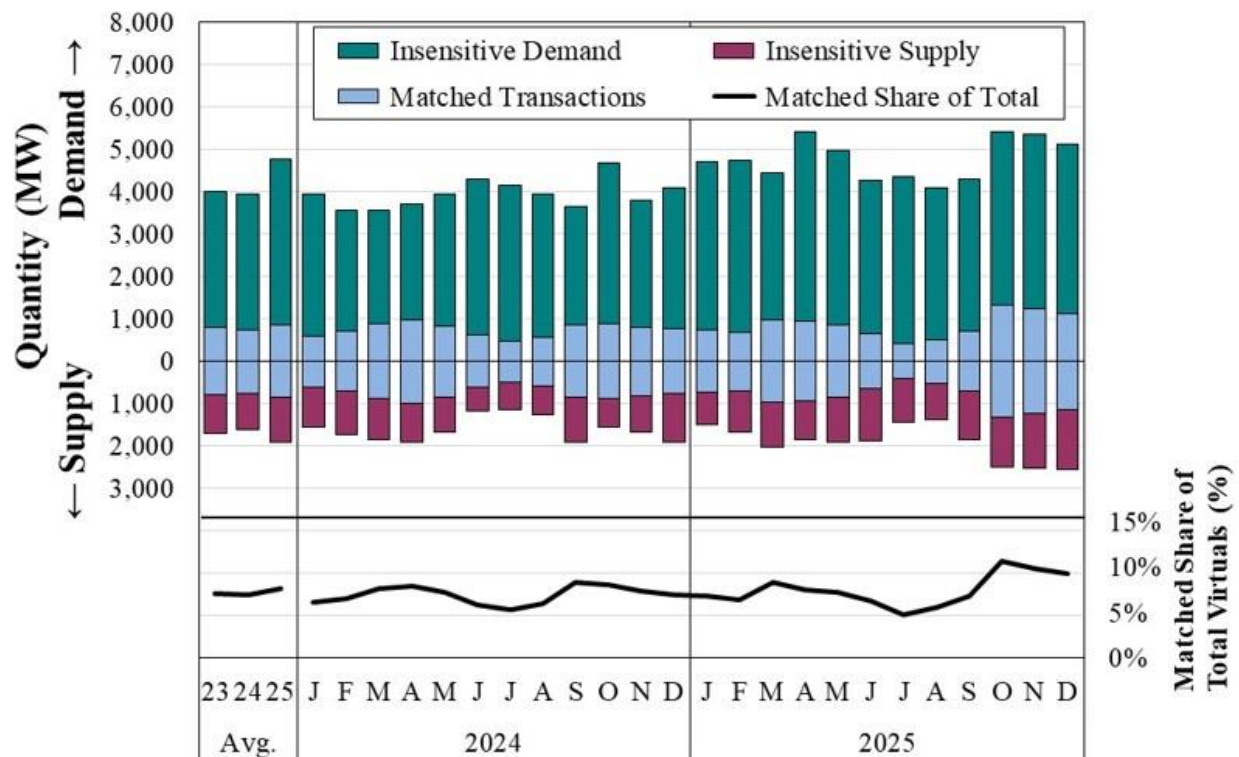
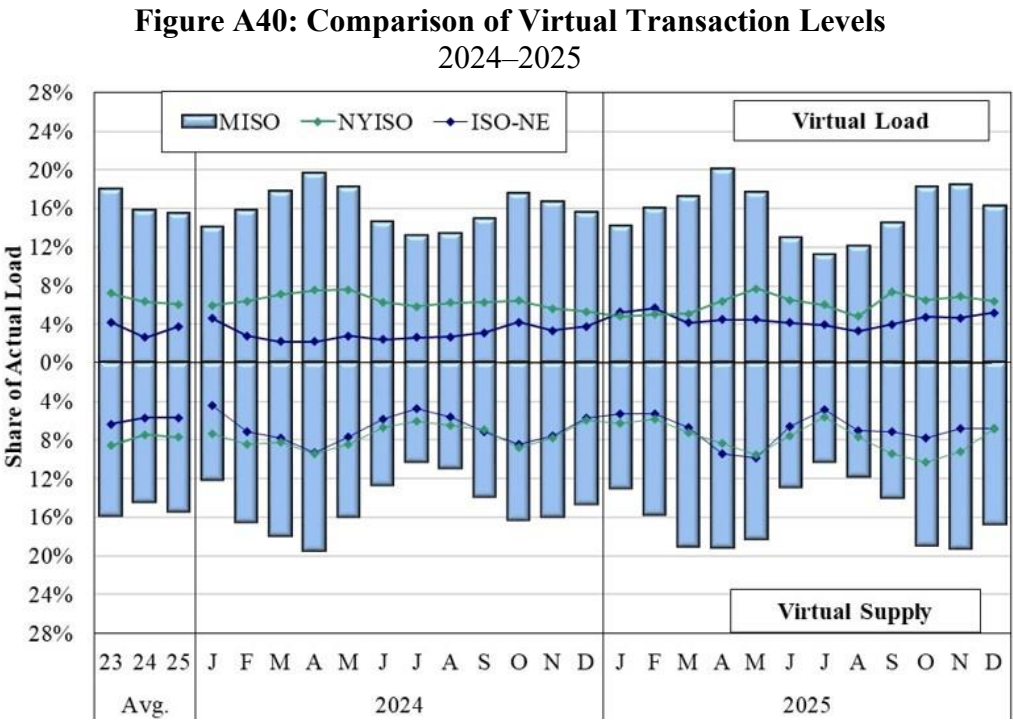


Figure A40: Comparison of Virtual Transaction Levels

Figure A40 compares trends in cleared virtual supply and demand in MISO, ISO-NE, and NYISO as a share of actual load.



F. Virtual Profitability

The next set of charts examines virtual-transaction profitability in MISO. In a well-arbitraged market, profitability should be low. However, when the day-ahead market has a prevailing premium, virtual supply should be generally more profitable than virtual demand.

Table A2: Comparison of Virtual Trading Volumes and Profitability

Table A2 compares virtual trading in MISO with trading in NYISO, ISO-NE, SPP, and PJM.

Table A2: Comparison of Virtual Trading Volumes and Profitability
2025

2025 Market	Virtual Load		Virtual Supply	
	MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit
MISO	15.5%	-\$0.30	15.5%	\$1.49
NYISO	6.1%	\$3.39	7.7%	\$1.25
ISO-NE	4.5%	-\$3.19	8.0%	\$2.67
SPP	11.6%	\$1.80	16.7%	\$3.60
PJM	5.9%	\$1.01	6.0%	\$1.24

Figure A41 to Figure A42: Virtual Profitability

Figure A41 and Figure A42 show monthly profits and average gross profitability of cleared virtuals, in aggregate and by participant type. Gross profitability is the difference between day-ahead and real-time prices and excludes RSG cost allocations.

Figure A41: Virtual Profitability
2024–2025

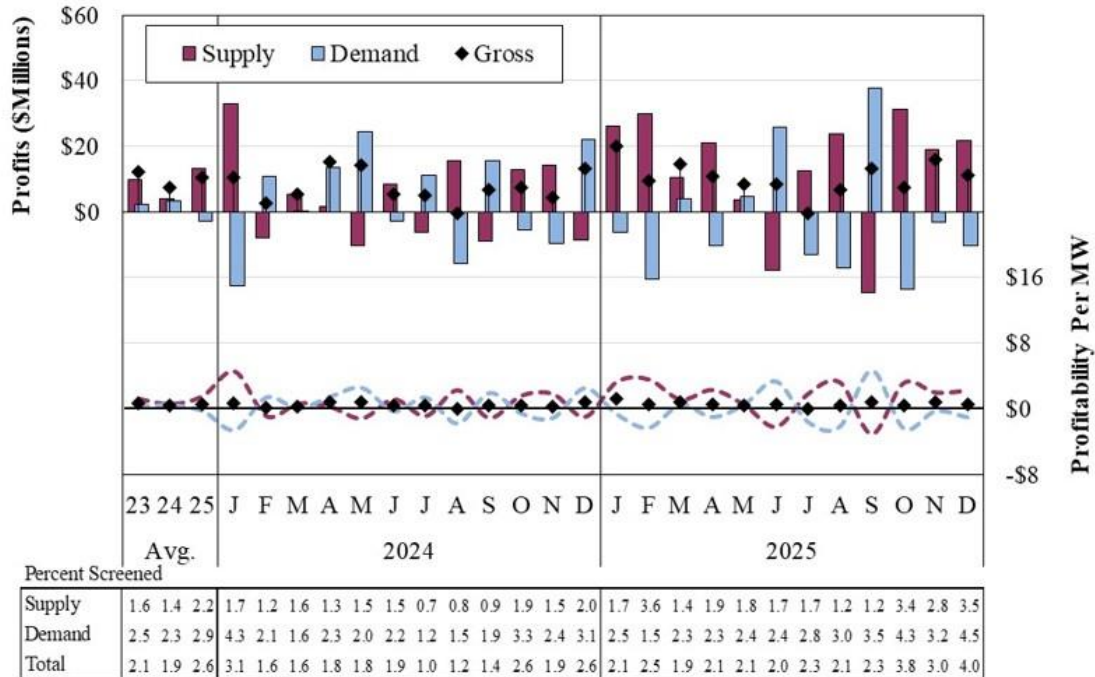
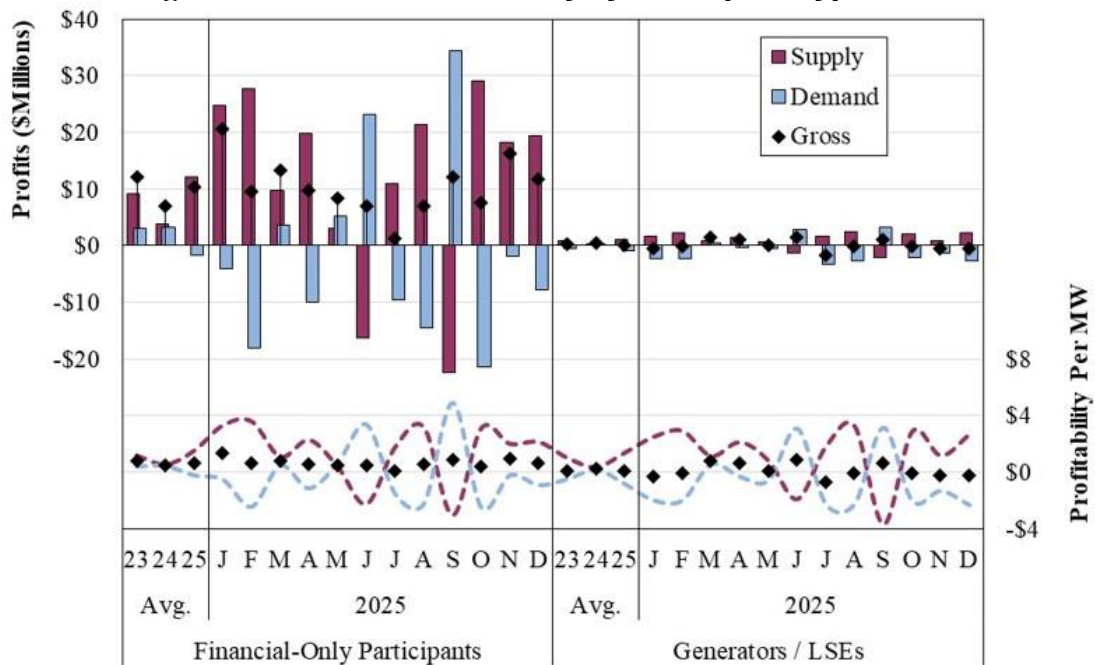


Figure A42: Virtual Profitability by Participant Type in 2025



G. Benefits of Virtual Trading

We conducted an empirical analysis of virtual trading in 2025 to evaluate virtual transactions' contribution to the efficiency of market outcomes. We categorized virtual transactions into those that improved market efficiency, as evidenced by profitability on consistently modeled constraints; those that did not improve efficiency, as evidenced by unprofitability; and those that, while profitable, did not produce efficiency benefits. We examined the results in quantities (MWh) and net profits.

The virtual transactions in each category indicate what percentage of virtual activity contributed to market efficiency. Net profits, calculated as the difference between profits and losses on consistently modeled constraints, indicate whether virtual transactions improved market efficiency in MISO by producing incrementally better day-ahead commitments and better convergence.

We first identified constraints that were modeled consistently in the day-ahead and real-time markets and those that were not. We categorized efficiency-enhancing virtual transactions as those that were profitable based on congestion modeled in the day-ahead and real-time markets and the marginal energy component (system-wide energy price). We excluded transactions that were profitable because of unmodeled constraints or divergence in day-ahead and real-time marginal loss factors. Profits from these factors do not lead to more efficient day-ahead market outcomes. We also identified virtual transactions that were unprofitable but efficiency-enhancing because they improved price convergence. This occurs when virtual transactions respond to a real-time price trend but overshoot and ultimately become unprofitable at the margin.

We designed tests based on an observed transaction at time t and an associated lagged value ($t-24$ for observations in hours 0–11 and $t-48$ for observations in hours 12–24). These lagged values correspond to the prevailing real-time prices visible when a participant submitted bids or offers for the next day in the day-ahead market. We used three tests to identify unprofitable, efficiency-enhancing virtual transactions:

- **Convergence Test:** Whether the absolute difference between the day-ahead and real-time LMPs at time t was smaller than the absolute difference between the day-ahead and real-time LMPs in the lagged time period.
- **Day-Ahead Price Movement Test:** Whether movement in the day-ahead price improved convergence, defined as the absolute difference between the day-ahead and real-time LMP at time t being smaller than the absolute difference between the lagged day-ahead price and the current real-time price.
- **Virtual Directional Test:** Whether the virtual trade moved the day-ahead price in the right direction—the virtual bid or offer would have been profitable based on the lagged difference between the day-ahead and real-time price.

Virtual transactions that did not improve efficiency were unprofitable based on energy and congestion on modeled constraints and did not contribute to price convergence.

Table A3 to Table A5: Efficient and Inefficient Virtual Transactions in

The following tables summarize 2025 virtual transaction quantities, profits, and losses in the efficiency-enhancing and non-efficiency-enhancing categories. Table A3 to Table A5 show all participants combined, financial participants, and physical participants.

Table A3: Efficient and Inefficient Virtual Transactions in 2025

Year: 2025	All Participants			
	MW	Convergent Profits	Rent-Seeking Loss	Rent-Seeking Congestion
Efficiency Enhancing (Profitable)	103,413,436	\$1,658,797,429	\$7,739,931	-\$49,414,754
Efficiency Enhancing (Unprofitable)	16,014,786	-\$141,193,097	\$8,222,736	\$21,775,584
Not Efficiency Enhancing (Profitable)	6,619,945	-\$39,962,811	\$10,393,358	\$82,754,640
Not Efficiency Enhancing (Unprofitable)	85,166,295	-\$1,455,183,126	\$21,917,707	-\$335,552
Total	211,214,462	\$22,458,395	\$48,273,732	\$54,779,918

Table A4: Efficient and Inefficient Virtual Transactions in 2025 – Financial Participants

Year: 2025	Financial Participants			
	MW	Convergent Profits	Rent-Seeking Loss	Rent-Seeking Congestion
Efficiency Enhancing (Profitable)	93,583,084	\$1,513,801,889	\$8,059,945	-\$46,981,829
Efficiency Enhancing (Unprofitable)	14,313,700	-\$127,579,713	\$7,581,306	\$20,101,476
Not Efficiency Enhancing (Profitable)	5,993,685	-\$37,284,062	\$9,631,601	\$78,009,238
Not Efficiency Enhancing (Unprofitable)	75,396,812	-\$1,320,153,100	\$20,025,317	-\$956,367
Total	189,287,281	\$28,785,014	\$45,298,169	\$50,172,517

Table A5: Efficient and Inefficient Virtual Transactions in 2025 – Physical Participants

Year: 2025	Physical Participants			
	MW	Convergent Profits	Rent-Seeking Loss	Rent-Seeking Congestion
Efficiency Enhancing (Profitable)	9,830,352	\$144,995,540	-\$320,014	-\$2,432,925
Efficiency Enhancing (Unprofitable)	1,701,087	-\$13,613,384	\$641,430	\$1,674,108
Not Efficiency Enhancing (Profitable)	626,260	-\$2,678,749	\$761,756	\$4,745,403
Not Efficiency Enhancing (Unprofitable)	9,769,483	-\$135,030,026	\$1,892,390	\$620,815
Total	21,927,181	-\$6,326,619	\$2,975,563	\$4,607,401

The profits and losses shown in the tables above are useful because they account for some transactions being relatively more efficient or inefficient than others. Each table also shows rents earned by virtual transactions, which are profits that do not produce efficiency benefits. The rents reflect profits associated with un-modeled day-ahead constraints and differences in the loss components of the two markets. These rents generally do not indicate a concern with virtual trading, but rather opportunities for MISO to improve the consistency of its modeling between the day-ahead and real-time markets.

The total benefits are much larger than the marginal net benefits shown above because: a) profits from efficient virtual transactions become smaller as prices converge; and b) losses from inefficient virtual transactions become larger as prices diverge. Accurately calculating this total benefit would require re-running all day-ahead and real-time market cases for the entire year. Nonetheless, our analysis establishes with a high degree of confidence that virtual trading benefited market efficiency in 2025.

H. Evaluation of ELMP Effects

MISO reformed its day-ahead and real-time energy pricing by implementing the Extended Locational Marginal Pricing algorithm (ELMP) in 2015. ELMP ensures that prices reflect true system marginal costs because inflexible high-cost units are often needed but not recognized as marginal. The most prevalent class of such units is online natural gas-fired turbines. Because it is often not economic to turn them off (they are the lowest cost means to satisfy the system's energy needs), energy prices should reflect their running costs.

ELMP is a price-setting engine that does not affect dispatch. It reforms pricing by allowing online inflexible resources to set the LMP if they are economic. These resources include online "Fast-Start Resources" (currently including units that can start within 60 minutes) and demand response resources.

In addition to FSRs, emergency actions and resources can set prices in ELMP during declared emergencies. In September 2021, MISO implemented recommended improvements to its emergency pricing by expanding the set of resources that can set prices during emergency events¹⁰ and setting the minimum Tier 1 and 2 Emergency Offer Floor Prices at \$500 and \$1,000 per MWh, respectively.¹¹ MISO also updated the value of RPE constraints to \$200 per MWh during emergencies.

Figure A43 to Figure A45: ELMP Price Effects

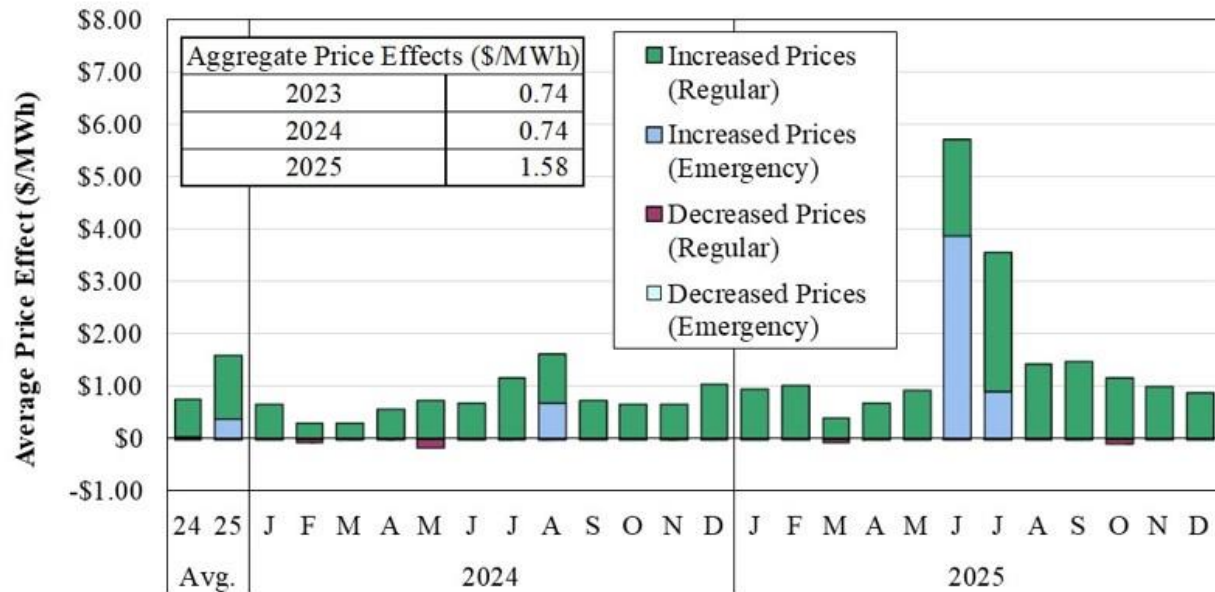
Figure A43 to Figure A45 summarize the effects of ELMP by showing the average upward effects from online pricing, the average downward effects from offline pricing, and the frequency with which the ELMP model changed prices upward and downward.¹² These metrics are shown for the market-wide "system marginal price" in the real-time and day-ahead energy markets, as well as for the LMP at the most affected locations (i.e., congestion-related effects). The tables below the first two figures also show the size of the ELMP price adjustments in the intervals when the ELMP model affected the price.

¹⁰ Resources offering up to four hours to start and a minimum run time up to four hours may now set the price during emergency conditions (Tier 0 Emergency Offer Floor Price) when MISO declares a Max Gen Alert.

¹¹ Tier 1 Emergency Offer Floor Prices apply when MISO declares a Max Gen Warning, while Tier 2 applies when MISO declares a Max Gen Event Step 2.

¹² MISO turned off the offline ELMP pricing in October 2021 until changes can be made in MISO's software that will only allow offline resources to set prices in ELMP if the LAC tool has committed resources within 10-15 minutes or the resources can start in 10-15 minutes.

Figure A43: The Effects of Fast Start Pricing in ELMP
Real-Time Market, 2024–2025



% of Intervals Affected by +/- \$0.10

SMP Increase	51	59	56	44	43	58	50	42	64	52	49	52	51	57	58	47	31	54	57	65	74	63	63	67	63	62
SMP Decrease	1	1	1	0	0	1	1	1	0	0	0	0	0	1	1	0	2	1	1	1	0	1	0	1	1	2

Figure A44: Average Market-Wide Price Effects of ELMP
Day-Ahead Market, 2025

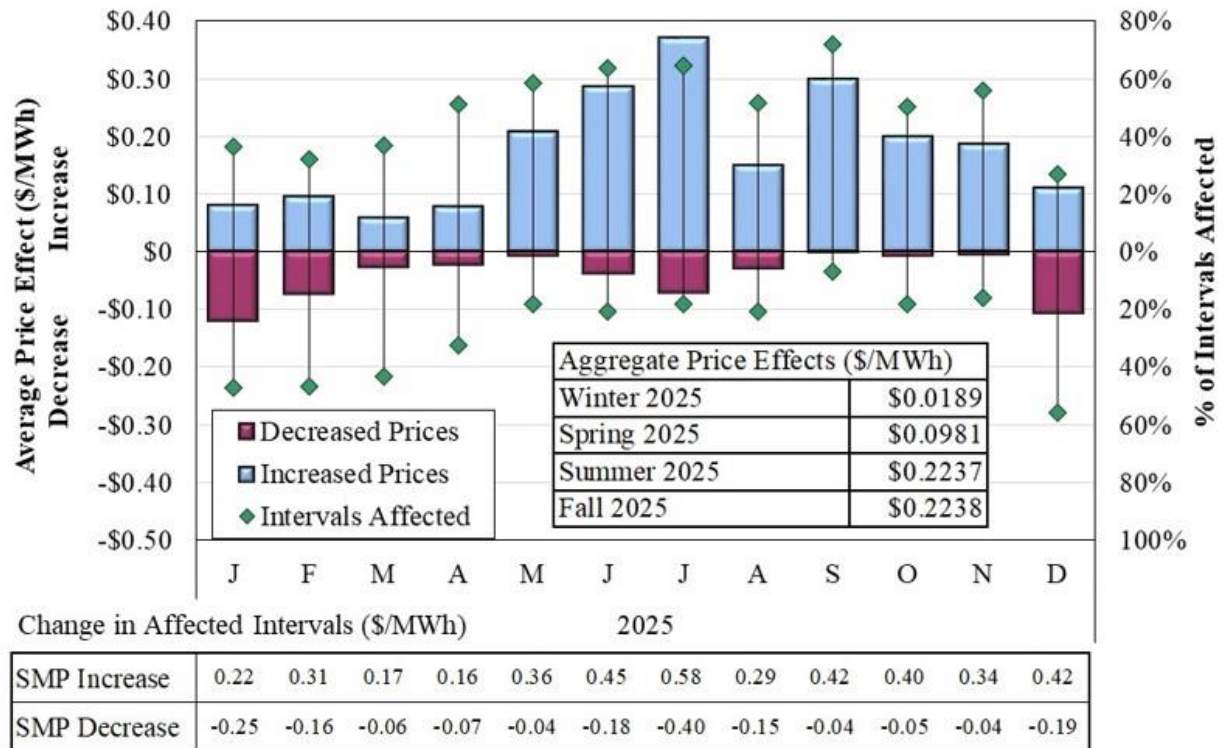


Figure A45: Price Effects of ELMP at Most Affected Locations
Real-Time Market, 2024–2025

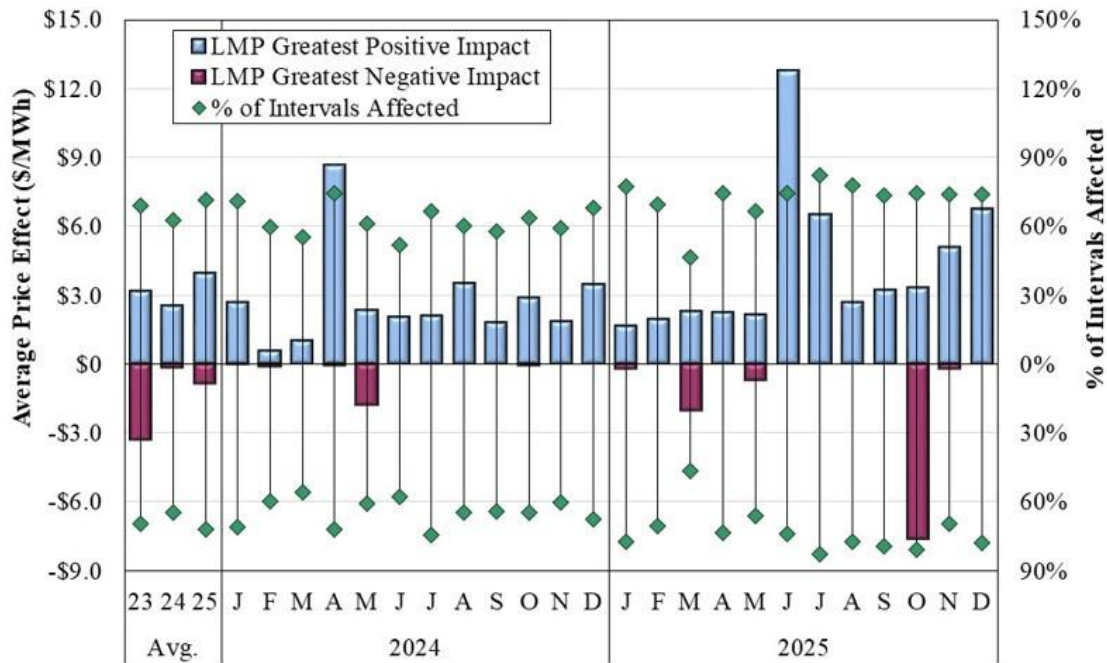


Figure A46 and Figure A47: EEA2 Pricing and RDT Flows

Figure A46 shows the ex-ante and ex-post pricing outcomes on June 10, 2021 when MISO declared an EEA2 event in the Midwest region and committed 3.2 GW of Midwest LMRs. The bottom panel shows the RDT flows, and the top panel shows the ex-post LMPs for the Midwest (red line) and South (blue line) alongside the ex-ante SMP (black dashed).

Figure A46: Actual EEA2 Pricing and RDT Flows
June 10, 2021

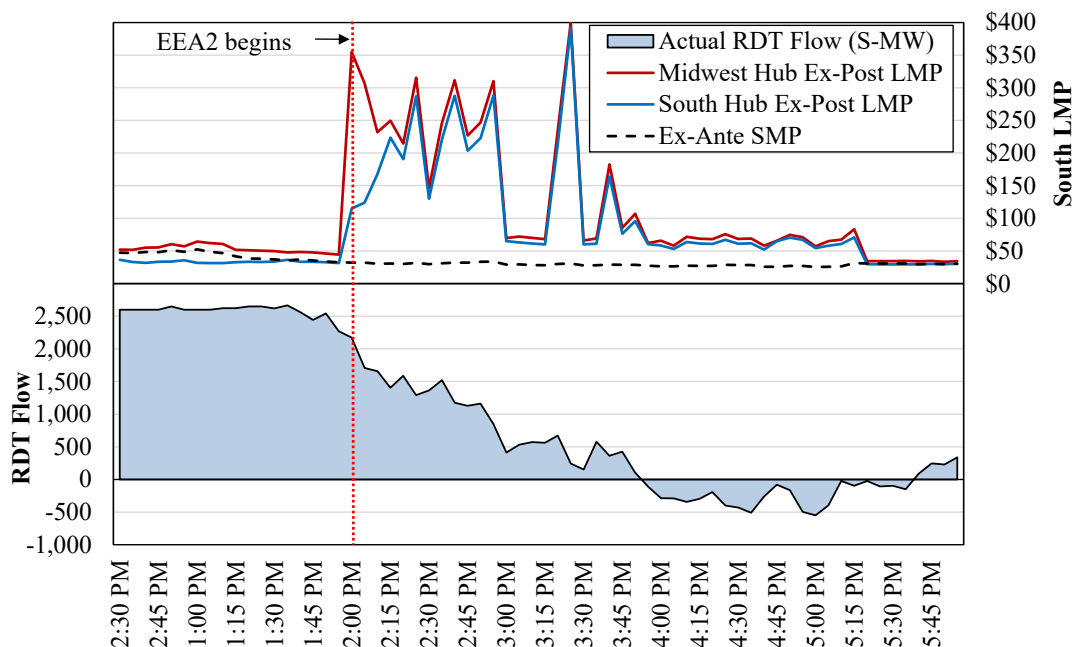
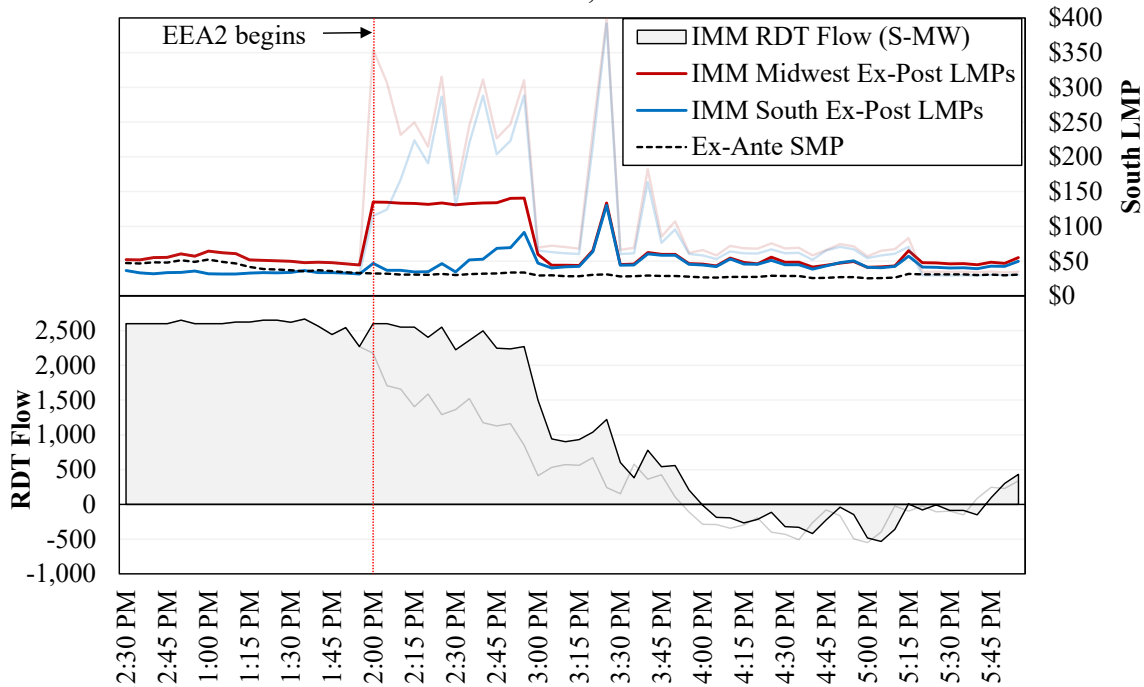


Figure A47 shows the same event after applying our recommendation to model LMRs as STR demand in the ELMP model. The lines from the first figure are semi-transparent to facilitate comparison with the alternative market solution.

Figure A47: Simulated, Proposed EEA2 Pricing and RDT Flows
June 10, 2021



I. Spinning Reserve Shortages

Figure A48: Market Spin Shortage Intervals Versus Rampable Spin Shortage Intervals

MISO operates with a minimum required amount of spinning reserves that can be deployed immediately for a contingency response. Market shortages generally occur because the costs that would be incurred to maintain the spinning reserves exceed the spinning reserve penalty factor (i.e., the implicit value of spinning reserves in the real-time market).

Units scheduled for spinning reserves may temporarily be unable to provide the full quantity in 10 minutes if MISO is ramping them up to provide energy. To account for concerns that ramp-sharing between ASM products could lead to real ramp shortages, MISO maintains a market scheduling requirement that exceeds its real “rampable” spinning requirement by more than 200 MW. As a result, market shortages can occur when MISO does not schedule enough resources in the real-time market to satisfy the market requirement but is not physically short of spinning reserves.¹³

Figure A48 shows all 2025 intervals with a real (physical) shortage, a market shortage, or both, along with the physical and market requirements.

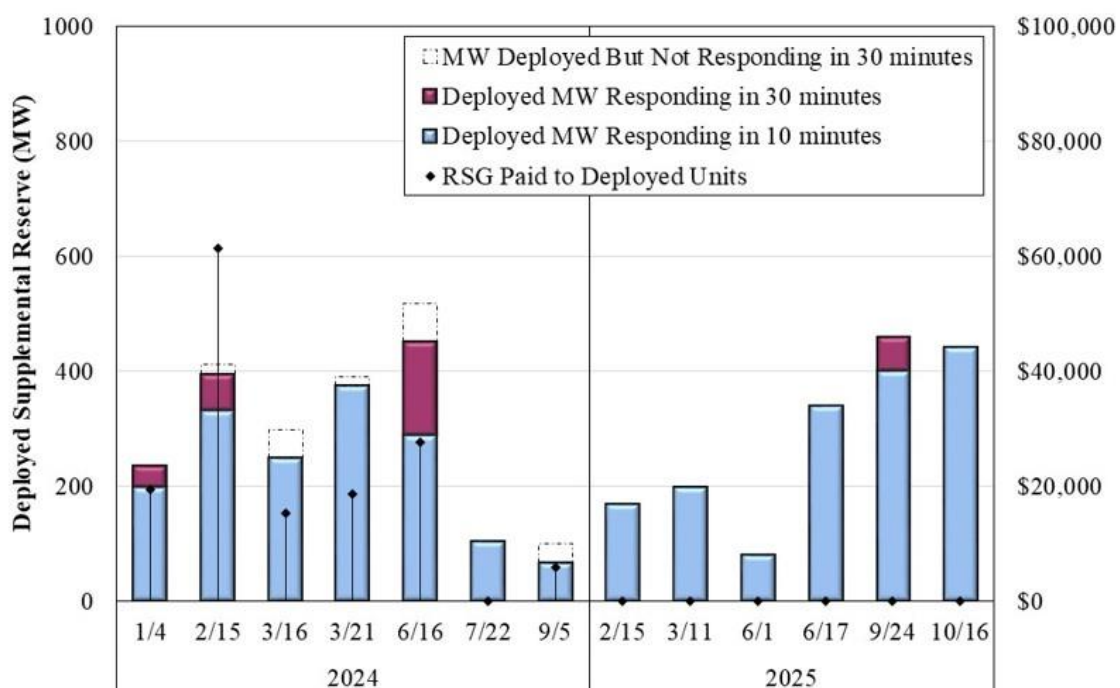
¹³ It is also possible for the system to be physically short temporarily, when units are ramping to provide energy, but not indicate a market shortage because ramp capability is shared between the markets.

Figure A48: Market Spin Shortage Intervals Versus Rampable Spin Shortage Intervals

J. Supplemental Reserve Deployments

Figure A49: Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard and Area Reserve Sharing events. Figure A49 shows offline supplemental reserves deployed in 2024 and 2025 and separately identifies those successfully deployed within 10 and 30 minutes.

Figure A49: Supplemental Reserve Deployments

The figure includes the RSG payments to deployed offline reserves. Because the market does not consider their commitment costs when scheduling supplemental reserves, high uplift payments could indicate a need to consider expected deployment costs when scheduling reserves.

K. Uplift Costs: RSG Payments

RSG payments compensate generators that MISO commits when market revenues are insufficient to cover the generators' production costs.¹⁴ MISO generally makes most of these out-of-merit commitments in real time to satisfy system reliability needs and account for changes after the day-ahead market. Because these commitments receive revenues from the real-time market, real-time RSG payments recover production costs that exceed those revenues. MISO commits resources in real time for many reasons, including to (a) meet capacity needs that arise during peak load or sharp ramping periods, (b) meet real-time load that was under-scheduled in the day-ahead market, or (c) secure a transmission constraint, satisfy a local reliability need, or maintain voltage in a location.

MISO makes many voltage and local reliability (VLR) commitments, predominantly in the day-ahead market. Most VLR commitments occur in the South region to manage load pocket requirements. To satisfy these requirements and accommodate the startup times of the required resources, MISO makes reliability commitments in advance or in the day-ahead market. A significant portion of day-ahead RSG is associated with these VLR resources.

Peaking resources are most likely to receive RSG payments because they are the highest-cost class of resources and, even when they set the price, receive minimal LMP margins to cover their startup and no-load costs. In addition, peaking resources often do not set the energy price because they operate at their economic minimum, so a lower-cost unit sets the price. This increases the likelihood that an RSG payment will be required.

Figure A50 and Figure A51: RSG Payments

Figure A50 shows total day-ahead RSG payments and distinguishes between payments for VLR and capacity needs. It separately identifies capacity payments to units in MISO South NCAs because these units are typically committed for VLR and are frequently subject to tighter VLR mitigation criteria. In August 2022, MISO implemented a new op guide to incorporate the impacts of adding a large, 1 GW combined-cycle facility in WOTAB in early 2021. The categorized columns represent monthly nominal RSG, and the green circles represent total monthly RSG adjusted for changes in fuel prices. Figure A51 shows total real-time RSG payments and distinguishes among payments to resources committed for overall capacity needs, congestion management, or voltage support.

¹⁴ Specifically, this is the lower of a unit's as-committed or as-dispatched offered costs.

Figure A50: Day-Ahead RSG Payments
2024–2025

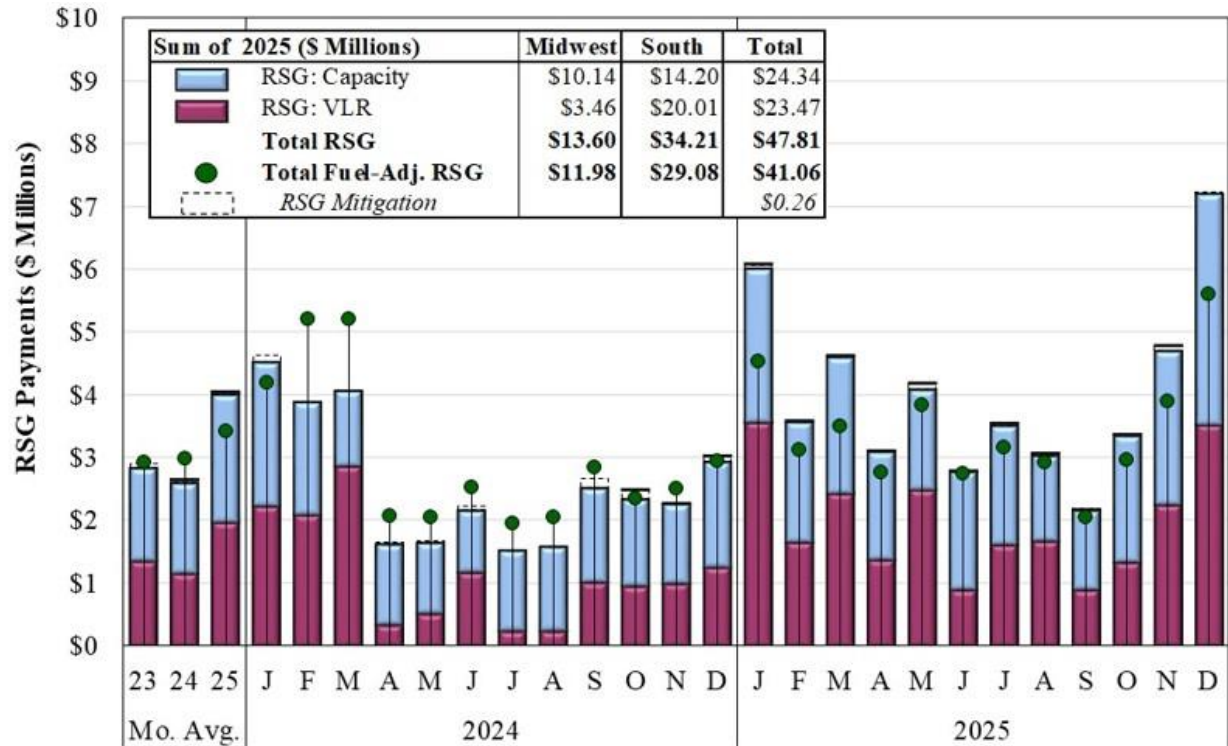


Figure A51: Real-Time RSG Payments
2024–2025

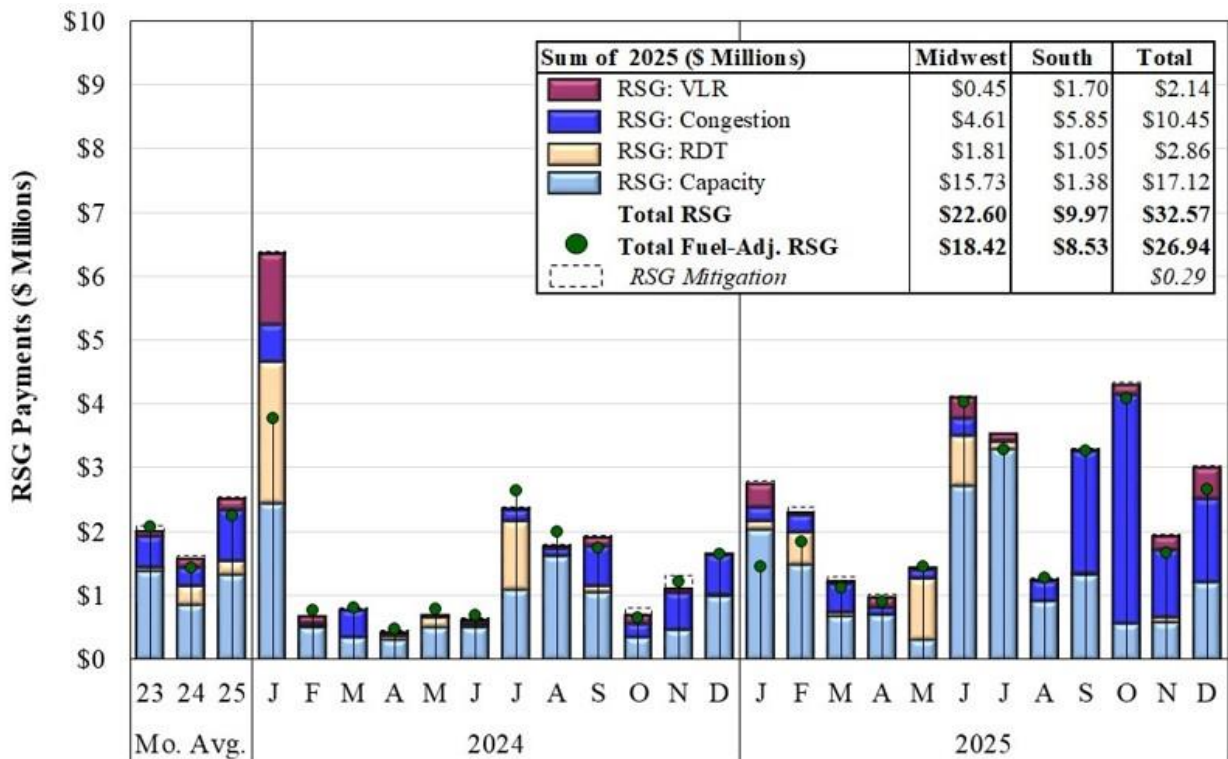


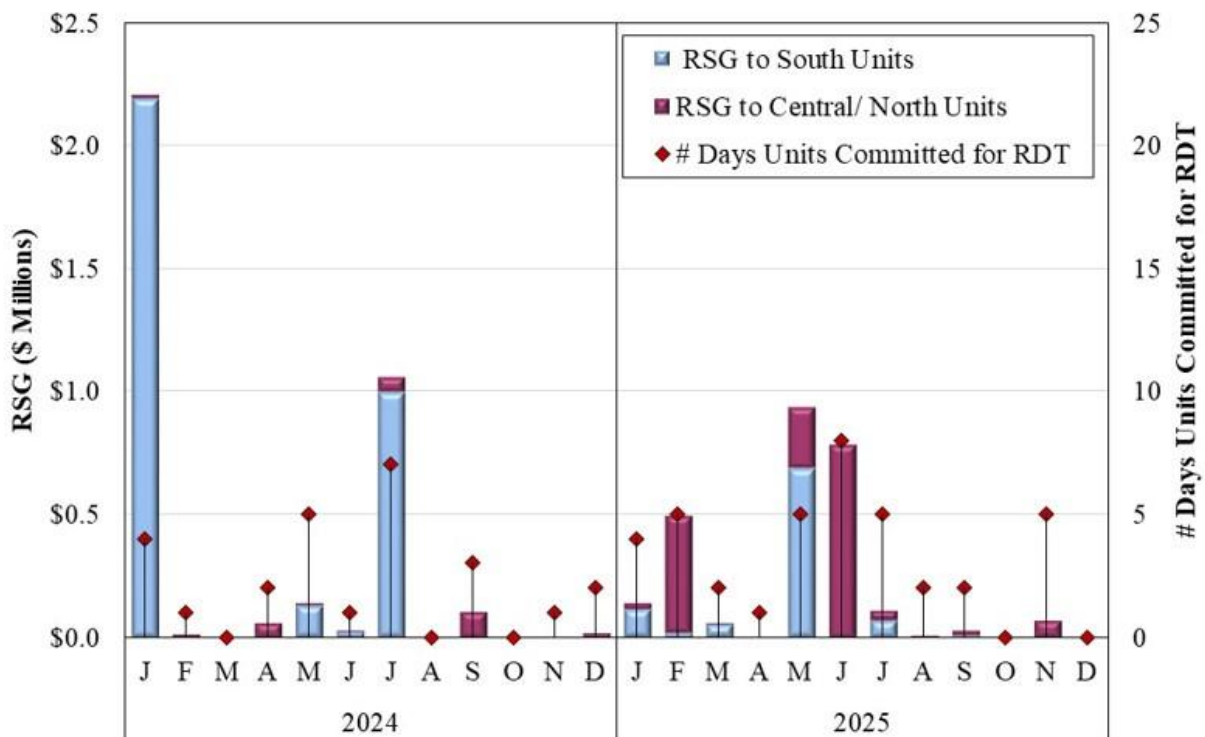
Figure A52: RSG for Units Committed for RDT

MISO has made many resource commitments in the Midwest or South to satisfy regional capacity needs when the Regional Directional Transfer constraint is binding or may bind. These commitments are not generally needed to manage dispatch flows over the RDT, but they ensure sufficient capacity is available in the importing region.

MISO makes these commitments outside the market because its markets do not include regional capacity requirements. MISO allocates the commitment costs across the entire footprint under the DDC rate. We evaluated the magnitude of these costs to assess the benefit of a regional reserve product, which FERC approved in January 2020. MISO implemented the “Short-Term Reserve” product in December 2021.

Figure A52 shows the total RSG MISO incurred for these commitments since January 2024 and the region in which the commitments were located (Midwest or South). The maroon bar segments show RSG payments to resources in the Midwest, and the blue bar segments show resources committed in the South region.

Figure A52: RSG for Units Committed for RDT
2024–2025

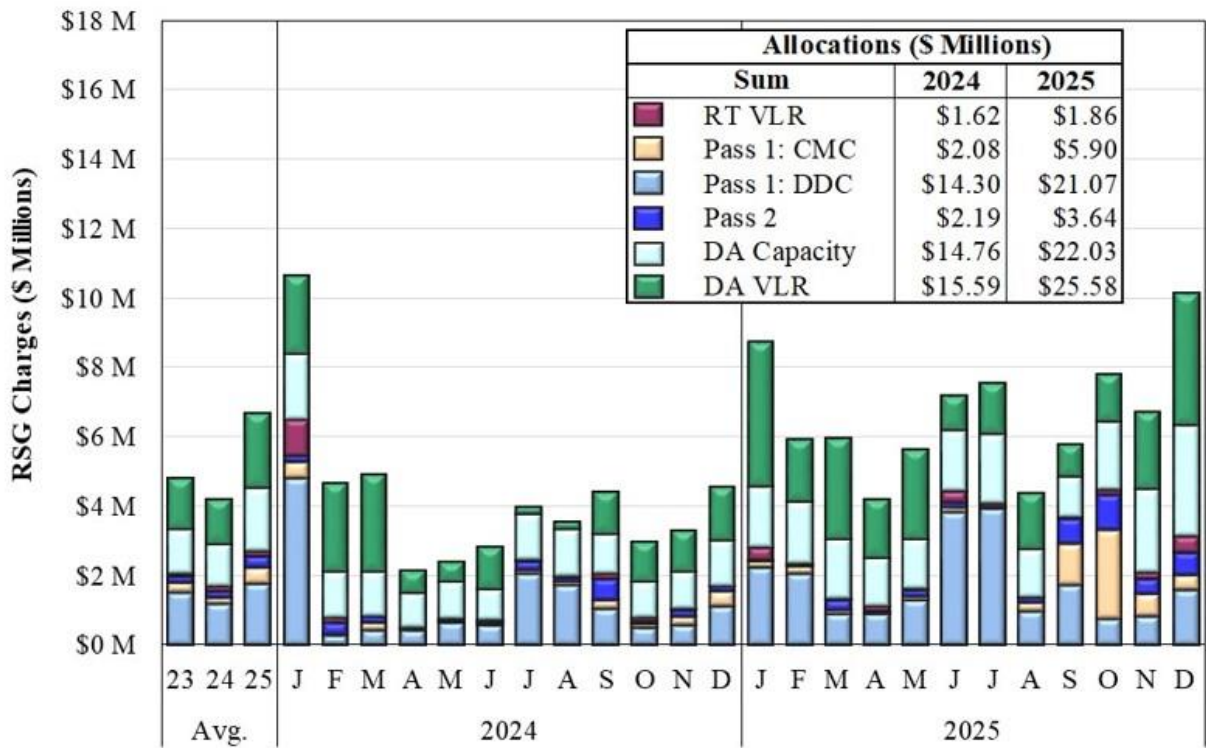
*Figure A53: Allocation of RSG Charges*

MISO substantively revised the RSG process in April 2011 to better reflect cost causation. Under the revised allocation methodology, RSG-eligible commitments are classified as satisfying either congestion management (or another local need) or a capacity need. When committing a resource for congestion management, MISO operators identify the particular constraint being relieved.

The Constraint Management Charge (CMC) rate allocates a share of the RSG costs to supply and demand deviations from the day-ahead market that contribute to the need for the commitment or increase flow on the identified constraint. It then allocates any residual RSG cost market-wide on a load-ratio-share basis (“Pass 2”).¹⁵

Figure A53 summarizes the monthly allocation of real-time RSG costs among the DDC, CMC, and Pass 2 charges from 2023 to 2025. Until March 2014, the CMC allocations were inappropriately limited based on the GSF of the committed unit. As a result, a significant portion of constraint-related RSG costs was allocated under the DDC charge. The figure also shows the RSG costs incurred to satisfy VLR requirements in the DA and RT markets, which are allocated locally. It also shows the RSG costs incurred to satisfy DA capacity, which are allocated market wide.

Figure A53: Allocation of RSG Charges
By Month, 2024–2025



L. Uplift Costs: Price Volatility Make-Whole Payments

MISO introduced the Price Volatility Make-Whole Payment (PVMWP) in 2008 to ensure adequate cost recovery from the real-time market for those resources offering dispatch flexibility. The payment ensures that suppliers following MISO’s dispatch signals do not incur financial harm, removing a potential disincentive to provide more operational flexibility.

¹⁵ A portion of constraint-related RSG costs may be allocated to “Pass 2” if they are associated with real-time transmission derates or loop flow.

The PVMWP consists of two payments: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Operating Revenue Sufficiency Guarantee Payment (RTORSGP). DAMAP is paid when a resource's day-ahead margin is reduced because it is dispatched in real time below its day-ahead schedule and must buy back its day-ahead scheduled output at real-time prices. This payment often results from short-term price spikes in the real-time market caused by binding transmission constraints or ramp constraints. Conversely, RTORSGP is paid to a qualified resource that cannot recover incremental energy costs when dispatched above its economic level in real time. Neither payment includes opportunity costs for potential revenues.

Table A6: Price Volatility Make-Whole Payments

Table A6 shows the annual totals for DAMAP and RTORSGP, along with the price volatility at the system level (SMP volatility) and at the unit locations receiving the payments (LMP volatility).

Table A6: Price Volatility Make-Whole Payments (\$ Millions)
2023-2025

	DAMAP		RTORSGP		Total	Market-Wide Volatility	Locational Volatility
	Midwest	South	Midwest	South			
2025	\$43.0	\$11.6	\$3.1	\$0.6	\$58.3	18.5%	21.2%
2024	\$44.8	\$8.1	\$3.4	\$0.6	\$56.8	20.9%	26.7%
2023	\$35.8	\$3.3	\$3.8	\$0.8	\$43.7	15.5%	21.0%

Table A7: Causes of DAMAP

In addition to the reliability consequences of resources failing to follow MISO's dispatch signals, prolonged dragging can cause substantial DAMAP. DAMAP costs arise when MISO dispatches generators below their day-ahead schedules when it is economic to do so, eroding margins earned in the day-ahead market.

This payment was intended to incentivize generators to be flexible and to hold them harmless if MISO directs them to dispatch down in response to real-time prices. DAMAP was not intended to hold generators harmless when they produce less output than would be economic because they are performing poorly. Previously, generators did not lose eligibility for DAMAP when they performed poorly, and we addressed this issue in our recommendations. In May 2019, MISO implemented changes to the Uninstructed Deviation (UD) thresholds and PVMWP formulations that reduced unjustified DAMAP payments.

Table A7 shows the causes of DAMAP in 2025 compared to 2024. It shows total DAMAP, the shares paid to units following MISO's dispatch signals, and the shares paid to units that do not follow dispatch signals well.

Table A7: Causes of DAMAP

Item Description	2024		2025	
	DAMAP (\$ Millions)	% Share	DAMAP (\$ Millions)	% Share
Following Instruction	\$32.0	82%	\$42.5	79%
SE Issue	\$0.8	2%	\$0.4	1%
Inferred Derate	\$1.6	4%	\$1.7	3%
Dragging - Failing New Threshold	\$1.2	3%	\$2.2	4%
Wind Unjustified	\$0.1	0%	\$0.1	0%
Dragging - Not Failing New Threshold	\$3.5	9%	\$7.2	13%
Total	\$39.2	100%	\$54.1	100%

M. Real-Time Commitment Patterns

Figure A54: Monthly Real-Time Capacity Commitments and RSG Costs

In 2021, we identified a pattern of increasing capacity-related commitments beginning in the summer months. To identify excess real-time capacity commitments and associated RSG (not needed to meet MISO’s requirements), we calculated the hourly difference between planned generation capacity and load¹⁶ in two ways: (1) using the forecast target load value for the run hour with the highest need¹⁷; and (2) using the actual load value in the run hour, assuming perfect foresight. Under these two scenarios, we flagged unit hours when planned generation capacity exceeded target load at the time of commitment. We ran these calculations for the Midwest and South subregions and for the MISO footprint¹⁸ – a unit had to be flagged as unneeded based on its own subregional needs and the MISO-wide needs to be considered excess.

Figure A54 shows RSG in millions of dollars for each month, as follows:

- “Actual Needed” RSG, denoted by green bars, from commitments not flagged as excess in either scenario;
- “Forecasted Needed” RSG, denoted by gray bars, from commitments flagged as excess under scenario (2) but not under scenario (1); and
- “Excess” RSG, denoted by dark blue bars, from commitments flagged as excess under both scenarios, delineated by the excess portion of the commitment.

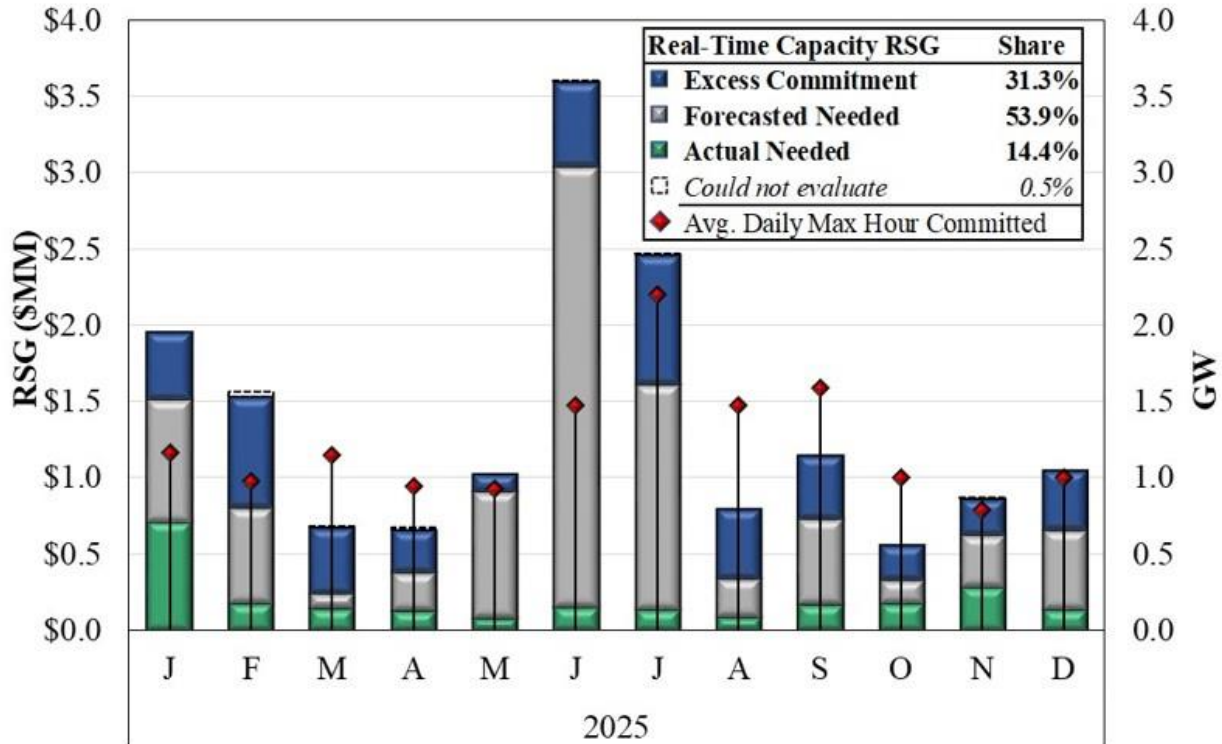
¹⁶ Planned generation capacity is Scheduled Generation MW + Reserves + Headroom, and Load is adjusted for NSI and the RDT (when assessed on a Subregional basis) and includes applicable reserve requirements.

¹⁷ We use hourly forecast data from the operating day. For each lead hour, we compare forecasted load (adjusted for scheduled NSI) to the generation in the plan prior to real-time commit decisions (e.g., day-ahead scheduled, must-run, reserves, and forecasted wind/solar) and all the available generation that can be started by the run hour. We use the target load from the lead hour with the tightest forecasted margin.

¹⁸ When evaluating the MISO footprint as a whole, we include offline units eligible for short-term reserves (STR) in planned generation and the prevailing STR requirement in the load (up to 4.5 GW). We additionally run an iteration where we omit offline STR units and only add the Contingency Reserve requirement to load (approximately 2.1 GW) to determine whether MISO was meeting online needs with commits.

The figure also plots the monthly average daily maximum commitment, in GW, against the right axis.

Figure A54: Monthly Real-Time Capacity Commitments and RSG Costs
2025



N. Generation Availability and Flexibility in Real Time

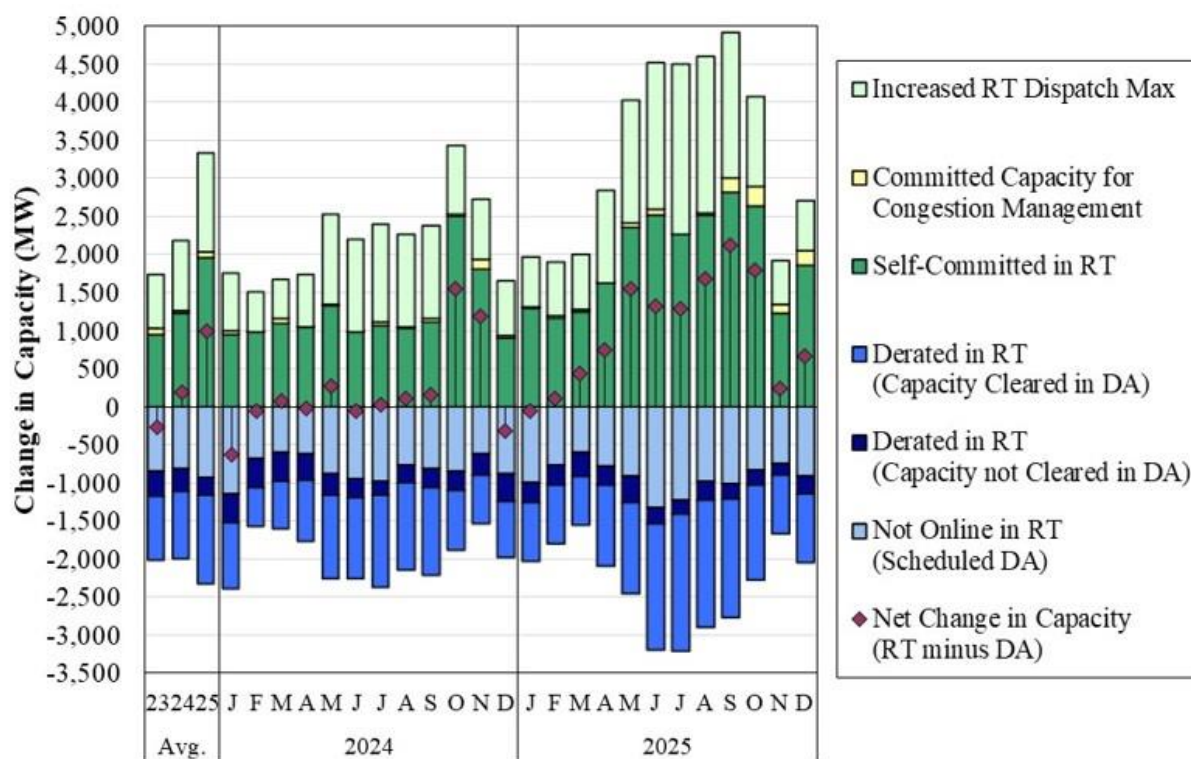
The flexibility of generation available to the real-time market allows MISO to manage transmission congestion and satisfy energy and operating reserve obligations. In general, the day-ahead market coordinates the commitment of most generation online and available for real-time dispatch. In real time, the dispatch flexibility of online resources allows the market to adjust supply every five minutes to accommodate NSI and load changes and manage transmission constraints.

Figure A55: Changes in Supply from Day Ahead to Real Time

Figure A55 summarizes changes in supply availability from the day-ahead to real-time markets. Differences between day-ahead and real-time availability generally result from real-time forced outages or derates and from real-time commitments and de-commitments by MISO or generation owners. The figure shows six types of changes: (1&2) generating capacity self-committed or de-committed in real time; (3) capacity scheduled in the day-ahead market but not online in real time; (4) capacity derated in real time, separated by resources cleared and not scheduled in the day-ahead market; (5) increased available capacity relative to day-ahead capacity; and (6) units committed for congestion management.

The figure separately shows the net change in capacity between the day-ahead and real-time markets. Net supply losses and other factors often cause MISO to commit additional capacity resources that the figure does not include.

Figure A55: Changes in Supply from Day Ahead to Real Time
2024–2025



O. Look Ahead Commitment Performance Evaluation

MISO’s Look Ahead Commitment (LAC) model minimizes the total production cost of committing sufficient resources to meet the short-term load forecast. It is MISO’s primary tool for making economic commitments of peaking resources in real time. To evaluate LAC performance, we compared its recommendations with the Unit Dispatch System results to determine whether the recommended commitments were economic. We also assess the extent to which MISO operators follow LAC recommendations.

Figure A56: Economic Evaluation of LAC Commitments

For this analysis, we labeled as “recommendations” resources that were online in a LAC solution but were not previously committed. We considered only recommendations that operators would have to act on before a new LAC case ran, based on the unit’s startup time, because operators generally wait to commit resources when possible. We ignored repeated recommendations within the unit’s minimum runtime to avoid overweighting repeated LAC recommendations that operators oppose. We determined whether recommendations would have been economic by comparing the unit’s estimated real-time revenues over its minimum runtime, using ELMP prices, to its total production cost, including start cost, no load costs, and incremental energy

costs. A unit was “started in real time” if it came online between the LAC recommendation and the end of the unit’s minimum runtime.

Figure A56: Economic Evaluation of LAC Commitments
2024–2025

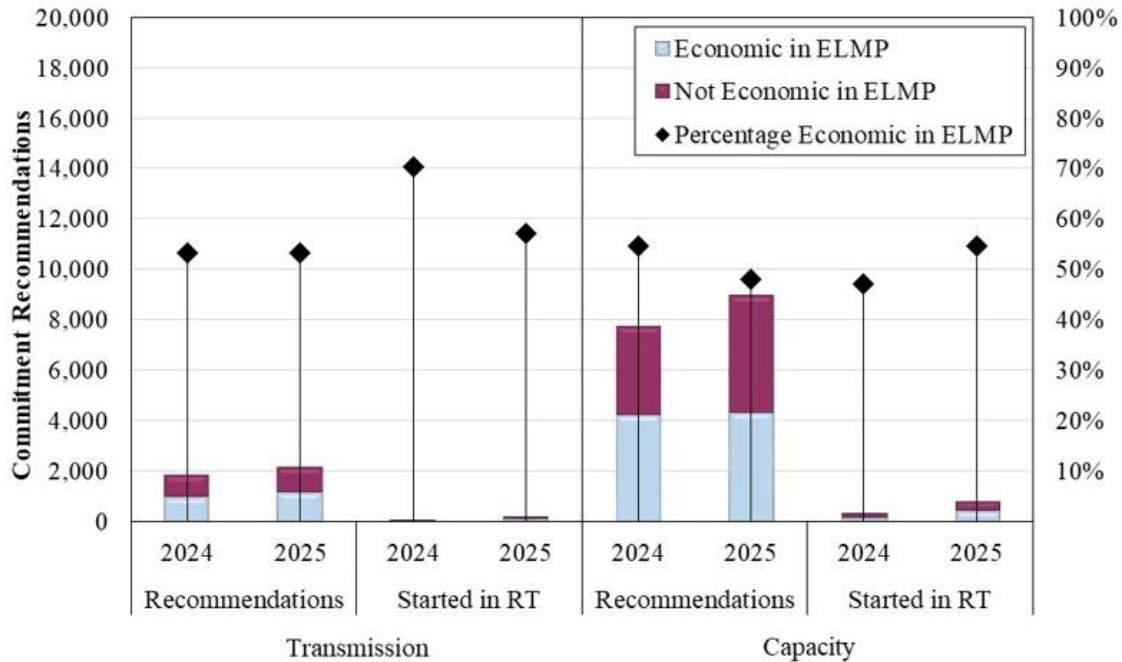


Figure A56 shows the results of our analysis. The left panel shows LAC commitment recommendations for transmission constraints, and the right panel shows all other LAC commitment recommendations. In each panel, the stacked bars on the left show the distinct recommendations that LAC made throughout 2024 and 2025 and indicate which recommendations were economic or not economic based on real-time ex-post energy prices. The stacked bars on the right show the share of recommended resources that actually started, distinguishing between those that were economic and not economic. The diamond in each bar indicates the share of recommendations that were economic.

P. Real-Time Dispatch Performance

MISO sends dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. Historically, MISO assessed penalties to generators if deviations from these instructions remained outside an eight-percent tolerance band for four or more consecutive intervals within an hour. However, in May 2019, MISO changed the UD threshold from output-based to a function of the offered ramp rate. MISO’s criteria for identifying deviations, including the percentage bands and the consecutive-interval test, were significantly more relaxed than those of most other RTOs.

A relatively relaxed tolerance band allowed resources to produce far less than their economic output level by responding poorly to MISO’s dispatch signals over many intervals (i.e., by “dragging” over an hour or more). Additionally, suppliers could effectively derate a unit by not moving over many consecutive intervals (i.e., “inferred derates”).

A resource can ignore its dispatch instruction as long as it remains within the allowable tolerance. Because the resource is still considered on dispatch, it can receive DAMAP and avoid the RSG charges it would otherwise incur if it were derated. These criteria exempt most deviation quantities from significant settlement penalties. In this section, we calculate two types of deviations to evaluate generator performance:

- Five-minute deviation is the difference between MISO's dispatch instructions and generators' responses in each interval.
- 60-minute deviation is the effect of generators not following MISO's dispatch instructions over 60 minutes.

We calculate the net 60-minute deviation as the difference between the energy generators would have produced if they had followed MISO's dispatch instructions over the prior 60 minutes and the energy they actually produced.

Figure A57 and Figure A58: Frequency of Net Five-Minute Deviations

Figure A57 shows a histogram of MISO-wide net five-minute deviations from 6 a.m. to 10 p.m., including MISO's high-ramp and peak hours in the summer and winter. Figure A58 shows the same results for the ramp-up hours. These hours are particularly important because MISO's need for generators to follow dispatch signals is greatest during them. When system demands increase rapidly and resources do not respond, MISO cannot satisfy its energy and reserve requirements. In each figure, the curve shows the share of deviations (on the right vertical axis) that are less than the deviation amount (on the horizontal axis). The markers on the curve indicate three points: the percentage of intervals with net positive deviations less than -500 MW, less than zero MW, and the median deviation.

Figure A57: Frequency of Net Deviations
Ramp and Peak Hours, 2025

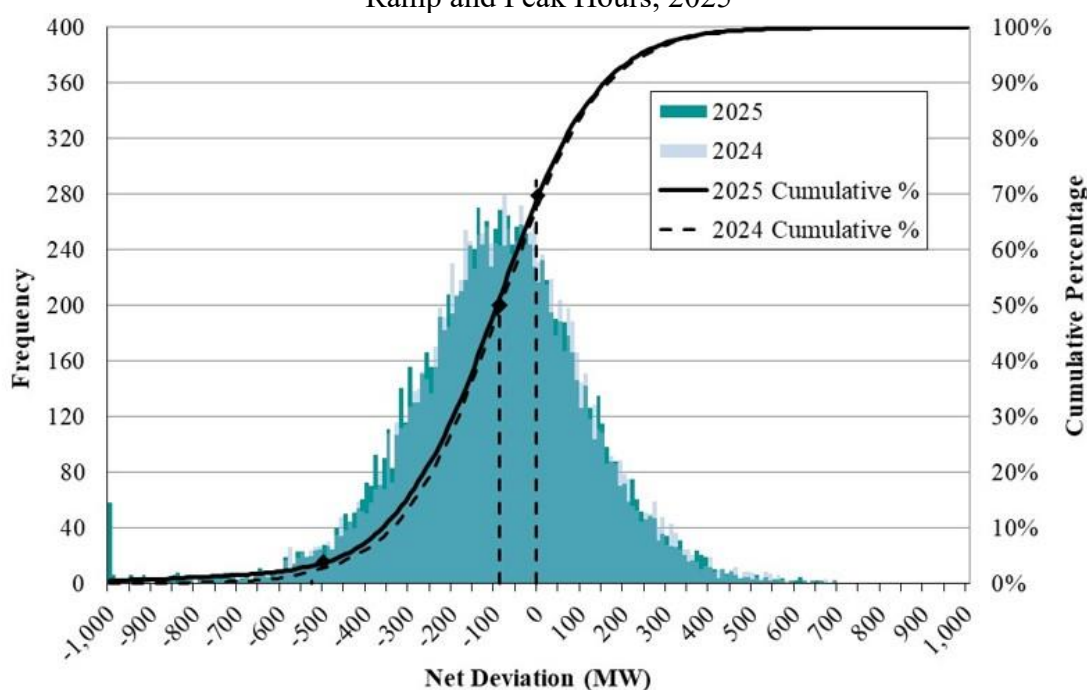


Figure A58: Frequency of Net Deviations
Ramp-Up Hours, 2025

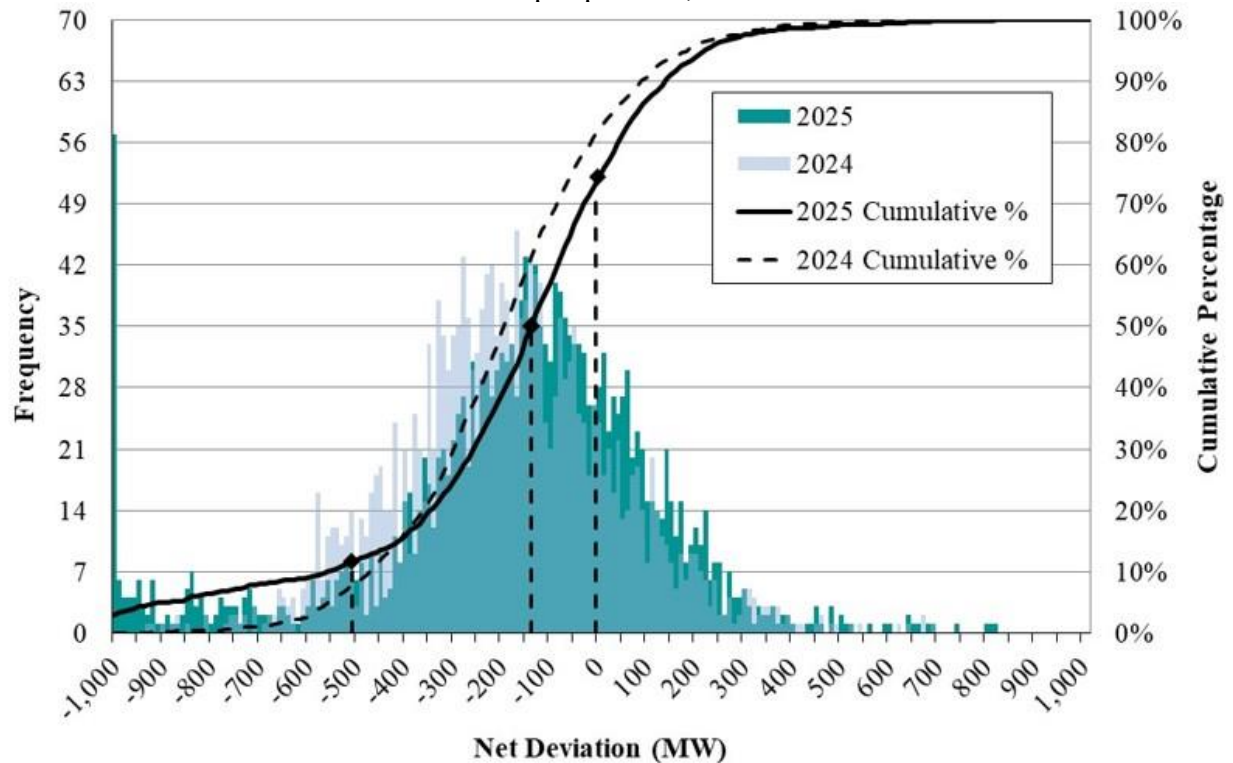


Table A8: Average Five-Minute and Sixty-Minute Net Dragging

Table A8 shows the size of the five-minute and 60-minute net deviations during ramp hours and all hours from 2021 through 2025. The columns to the right highlight the worst-performing 10 percent of resources and their average deviations.

Table A8: Average Five-Minute and Sixty-Minute Net Dragging
2021–5

	5-min Deviation Net		60-min Deviation Net		Worst 10%	
	Ramp Hours	All Hours	Ramp Hours	All Hours	Ramp Hours	All Hours
2025	(59)	(83)	(82)	(28)	226	174
2024	(129)	(149)	(96)	(26)	193	153
2023	(96)	(118)	(87)	(7)	247	182
2022	(218)	(312)	(87)	(11)	229	163
2021	(180)	(255)	(79)	(4)	165	186

Figure A59 to Figure A61: 60-Minute Deviation by Fuel and Hour

The next three figures show our estimates of the sources and impacts of 60-minute net deviations by fuel type. The stacked bars show the average 60-minute deviation for each hour (after 12 am): red for coal units, blue for gas units, and green for wind units. The three charts show the full year, winter only, and summer only.

Figure A59: 60-Minute Deviation by Fuel and Hour
2025

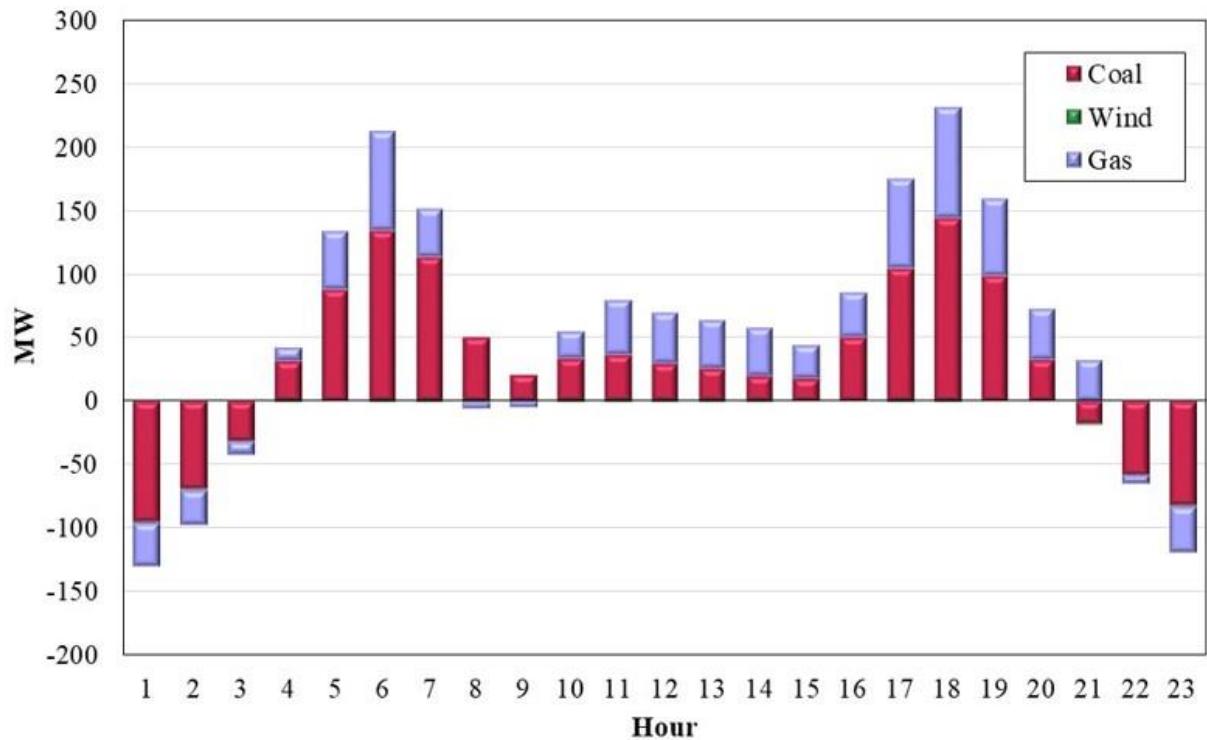


Figure A60: 60-Minute Deviation by Fuel and Hour
Summer 2025

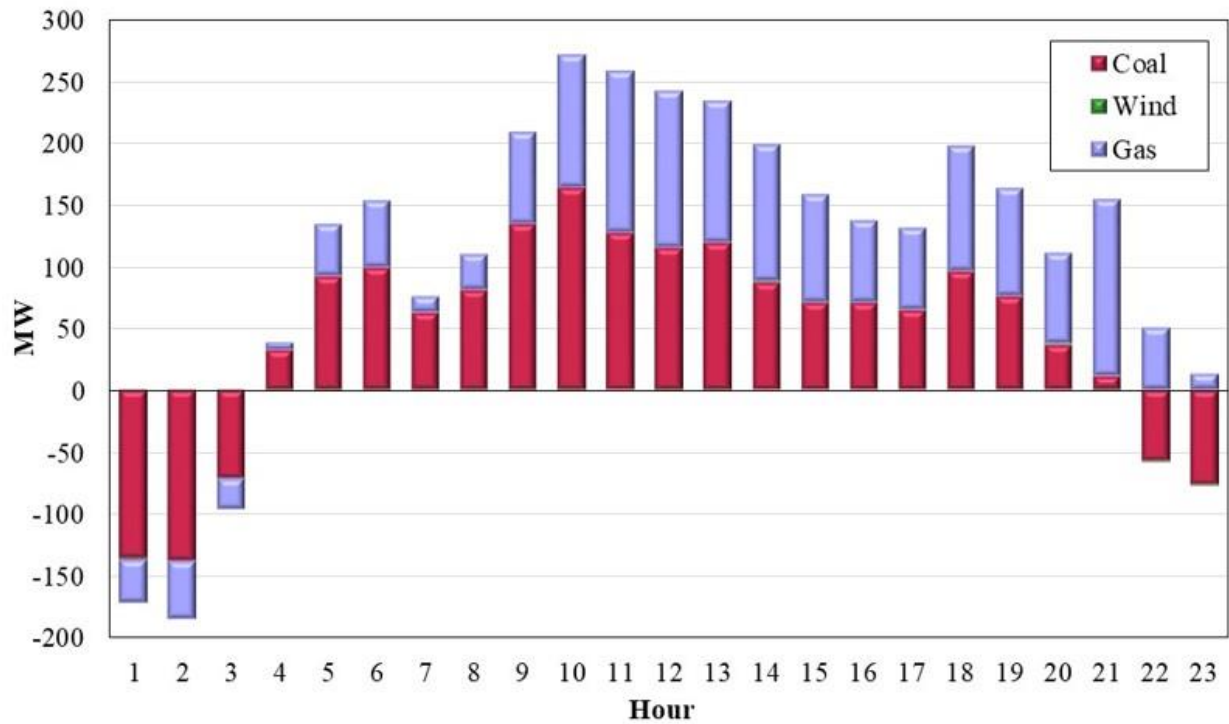


Figure A61: 60-Minute Deviation by Fuel and Hour
Winter 2025

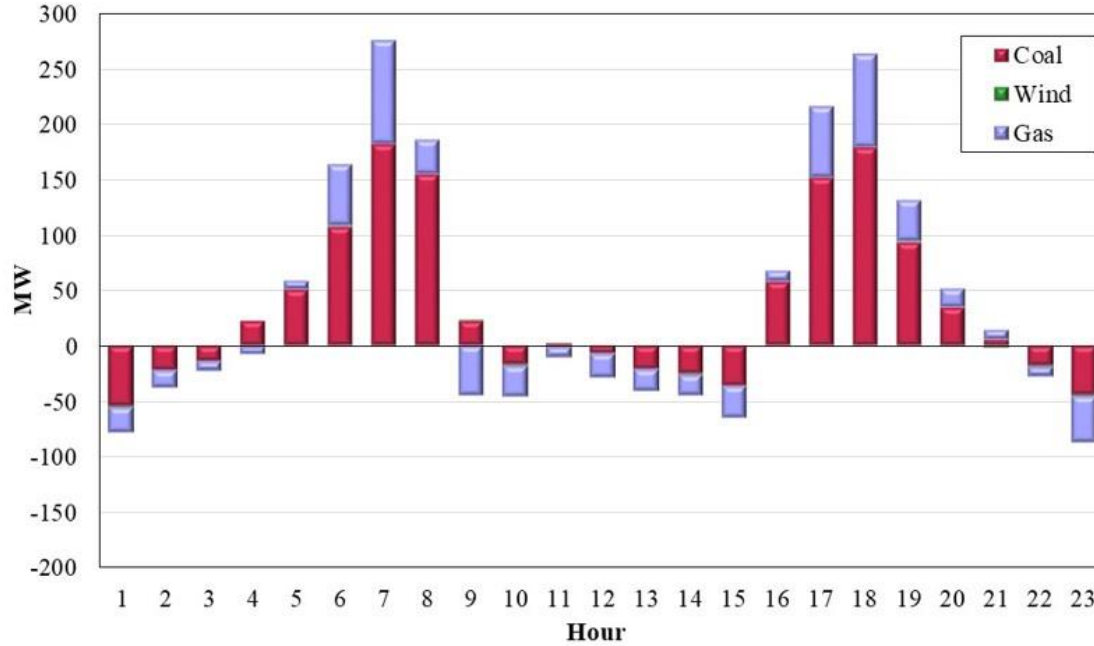


Figure A62: Hourly 60-Minute Deviations by Type of Conduct

To show the effects of the deviations more clearly, Figure A62 shows dragging by hour of the day and in the worst 10 percent of hours. The inset table shows the annual averages for dragging and overproduction across all hours.

Figure A62: Hourly 60-Minute Deviations by Type of Conduct
2025

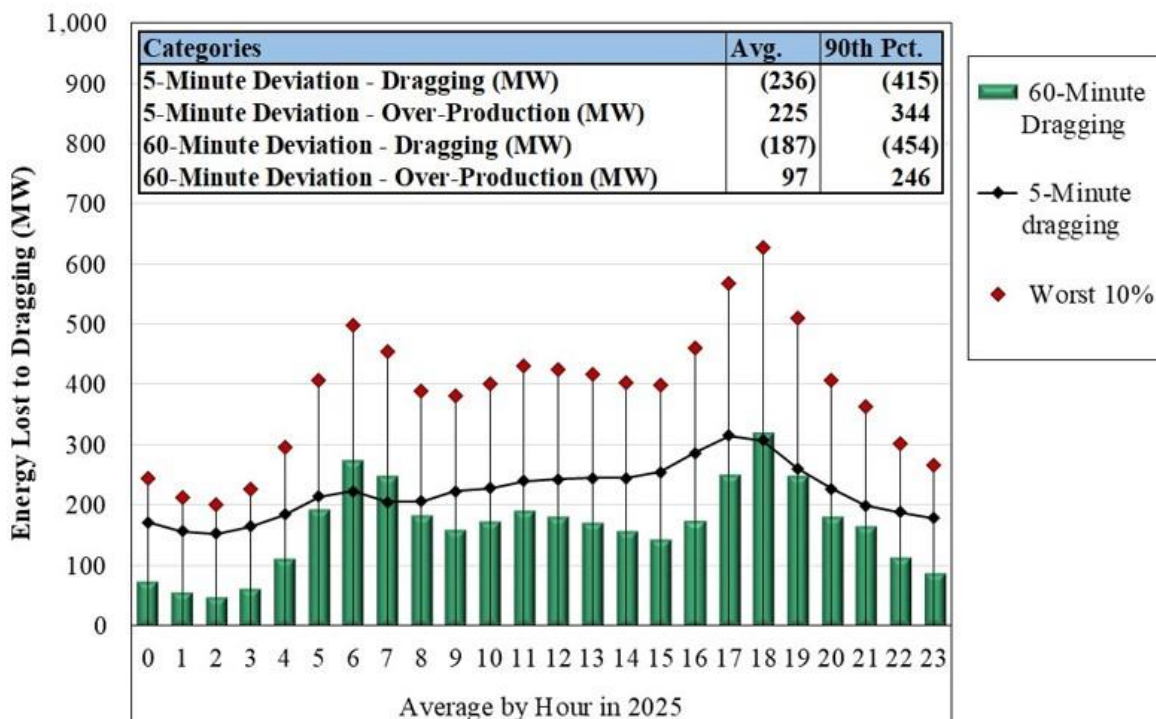


Figure A63: DAMAP to Dragging Units by Fuel Type

The next figure shows the DAMAP from 60-minute deviations. The vertical stacked bars show DAMAP in dollars for units with 60-minute deviations from their dispatch instructions for each hour (after 12 am). The bar colors represent fuel types: maroon for coal units, blue for gas units, and green for wind units.

Figure A63: DAMAP to Dragging Units by Fuel Type
2024–2025

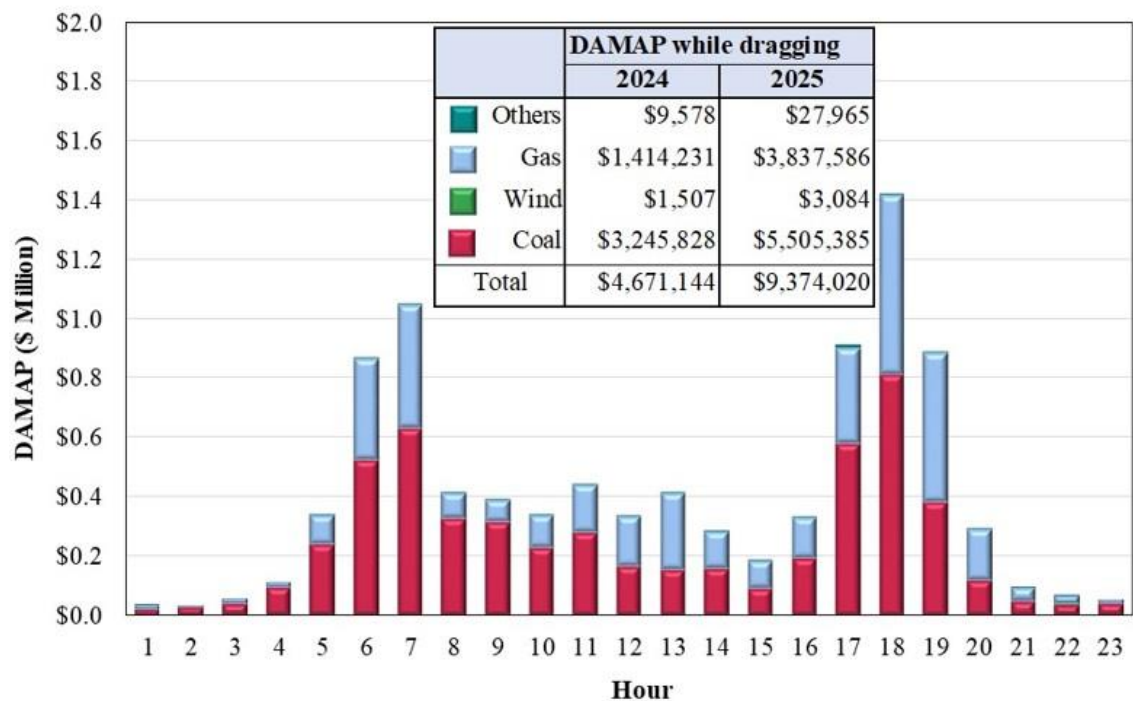


Table A9: Proposed Uninstructed Deviation Penalties and Effective Rate

The report shows that current settlement rules are insufficient for generation deviations outside the UD tolerance bands. For excessive or deficient energy that loads a constraint, we analyzed a penalty equal to an escalating share of the MCC, beginning at 25 percent in the first interval and rising to 100 percent by the fourth interval. Table A9 shows this penalty’s effects by unit type. Penalty rates are reported per MWh of deviation (columns 3 and 4) and per unit of total output (columns 5 and 6). The second column shows total penalties incurred during 2025.

Table A9: Proposed Uninstructed Deviation Penalties and Effective Rate

2025 Unit Type	Total Penalty	Avg. Deviation Penalty (\$/MWh)		Average Penalty (\$/MWh of Output)	
		Excessive	Deficient	Excessive	Deficient
Gas Turbine	\$234,649	\$8.42	\$0.51	\$0.003	\$0.000
Coal	\$222,404	\$2.98	\$0.30	\$0.001	\$0.000
Gas CC	\$249,526	\$3.87	\$1.53	\$0.001	\$0.001
Other	\$277,978	\$2.51	\$0.79	\$0.002	\$0.000
Solar	\$760,883	\$51.77	\$1.16	\$0.025	\$0.001
Wind	\$766,571	\$41.20	\$2.59	\$0.007	\$0.000

Figure A64: Excess Operating Reserve Payments to Units not Following Dispatch

We separately evaluated resources operating above or below their dispatch setpoint while clearing Operating Reserves. For resources in the Reserve Performance category, we used MISO’s existing hourly settlement performance factor, which MISO already calculates to determine eligibility for Real-Time PVMWPs. This factor is based on energy mileage and measures how closely a resource follows dispatch instructions over the market hour. Because it evaluates dispatch-following performance, it is also well suited to assess whether the resource’s real-time Operating Reserve capability is fully available.

We calculated each resource’s hourly Operating Reserve revenue and reduced it by applying the applicable settlement performance factor, using the lower of the current-hour and prior-hour factors. For resources operating above setpoint in the Reserve Excessive category, we estimated overpayments for spinning reserve, Short-Term Reserve, and Ramp Capability Up based on reserve MW in excess of the applicable Economic Maximum after accounting for the resource’s actual energy output. We further validated both analyses with a separate assessment based on five-minute generator dispatch and settlement data, which produced consistent results.

Figure A64: Excess Operating Reserve Payments to Units not Following Dispatch
2025

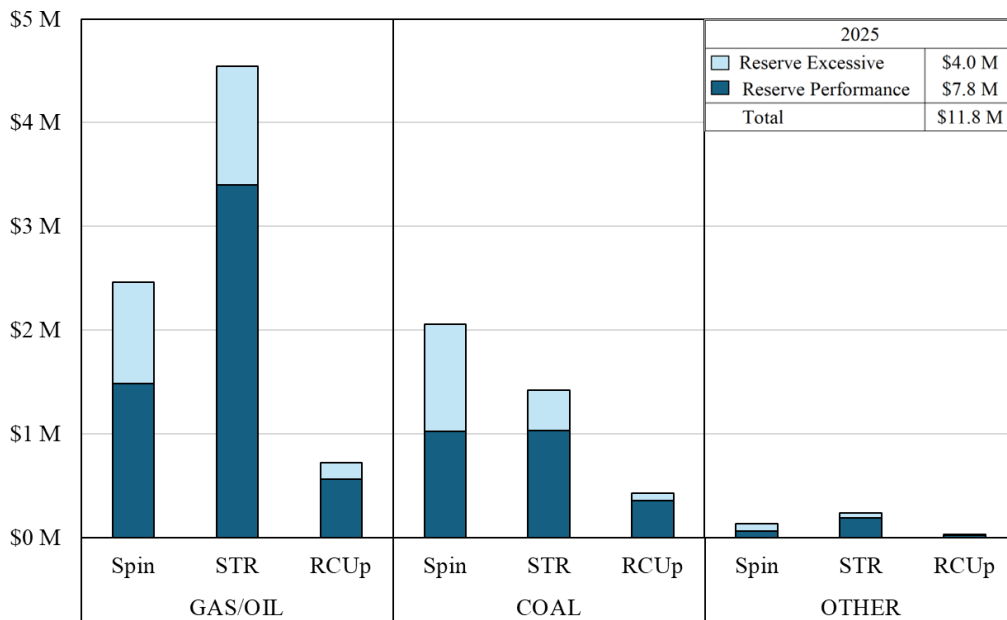


Table A10: Proposed Emergency-Range Penalties

We estimate the proposed penalties for generating resources that failed to follow dispatch instructions into their emergency ranges using generator performance from the two most recent capacity emergency days: June 23, 2025 and January 24, 2026. Our analysis applies penalty formulas similar to those for Load-Modifying Resources (LMRs), including existing LMP-based penalties and the Auction Clearing Price (ACP)-based penalties MISO filed with FERC in 2025.

We allowed a tolerance of 12 percent of the emergency range and included only units with at least six intervals of non-compliance. We excluded units in the South region because both emergencies concerned only units in the Midwest. We treated each unit's economic maximum during the first interval of the emergency as the bottom of the emergency range for the rest of the emergency. However, we did not penalize unit-intervals with emergency maximum and economic maximum within 1 MW.

The LMP-based penalties use the LMP at each resource's node and the resource's shortfall fraction in each qualifying penalty interval, summed across all qualifying intervals. The ACP-based penalties use each resource's average shortfall percent across all intervals when it was dispatched into its emergency range, the average UCAP value of the resource's emergency range, the applicable ACP, and the number of days in the applicable PRA season. Emergency-range capacity revenue equals the average UCAP value of emergency ranges multiplied by the number of days in the season and the applicable ACP.

Table A10: Proposed Emergency-Range Penalties

					ACP Penalty/Emergency- Range Capacity Revenue (%)	Emergency-Range Capacity Revenue (\$)
Fuel Type	Unit Type	LMP Penalty (\$)	ACP Penalty (\$)	Total Penalty (\$)		
June 23, 2025						
Coal	Steam Turbine	128,923	4,551,779	4,680,703	26%	17,546,819
Gas or Dual Fuel	Combined Cycle	8,123	350,659	358,783	3%	11,550,852
	Aggregate					
Gas or Dual Fuel	Combustion Turbine	273,257	6,439,012	6,712,269	24%	27,107,033
Gas or Dual Fuel	Other	11,747	346,057	357,804	86%	401,857
Gas or Dual Fuel	Other Peaker	20,055	69,943	89,998	100%	69,943
Gas or Dual Fuel	Steam Turbine	59,194	2,210,805	2,269,999	33%	6,637,271
Oil	Diesel	28,102	1,374,438	1,402,540	56%	2,461,110
Oil	Combustion Turbine	30,090	148,423	178,512	18%	816,098
Other	Other	34,197	298,918	333,115	68%	440,093
Pet Coke	Steam Turbine	5,556	200,278	205,834	30%	673,451
Water	Pumped Storage	10,634	341,278	351,912	31%	1,115,487
January 24, 2026						
Coal	Steam Turbine	250,384	668,701	919,085	16%	4,129,690
Gas or Dual Fuel	Combined Cycle	40,132	530,664	570,797	23%	2,284,268
	Aggregate					
Gas or Dual Fuel	Combustion Turbine	77,663	111,746	189,409	13%	884,983
Gas or Dual Fuel	Steam Turbine	3,485	3,197	6,681	1%	595,854
Oil	Diesel	66,395	36,283	102,678	59%	61,066
Oil	Combustion Turbine	1,062	110,369	111,430	24%	458,632
Pet Coke	Steam Turbine	27,399	13,581	40,980	58%	23,459
Waste	Steam Turbine	3,490	2,967	6,457	17%	17,574

Q. Coal Resource Operations

Table A11: Coal-Fired Resource Operation and Profitability

We screened every coal unit commitment between 2020 and 2025 and identified a commitment as economic when the committed resource:

- Offered economically and scheduled in the day-ahead market; or

- Offered with a must-run status and profitable, with market revenues covering commitment and variable operating costs by the first full day after commitment.¹⁹

In this analysis, we calculated hourly operating net revenue based on the units' reference prices. For coal units conserving coal, we used reference prices based on variable costs and excluded opportunity costs. For must-run units, we assumed start costs based on reference prices. We summed start costs across all starts and subtracted them from total operating revenues net of all operating costs.

Table A11 summarizes the results of this evaluation for three timeframes—2020 through 2023, 2024, and 2025—to distinguish among periods with different prevailing natural gas prices. In each timeframe, the third column summarizes the net operating revenues coal suppliers earned from their decisions to start and operate these resources. These values reflect the aggregate economic impact of the resource owners' decisions.

**Table A11: Coal-Fired Resource Operation and Profitability
2020–2025**

	2020-2023			2024			2025		
	Annual Starts	% of Starts	Net Rev. (\$/MWh)	Starts	% of Starts	Net Rev. (\$/MWh)	Starts	% of Starts	Net Rev. (\$/MWh)
Regulated Utilities	1687		\$9.60	1428		\$8.01	1304		\$17.43
Profitable Starts	1478	88%		1215	85%		1231	94%	
<i>Offered Economically</i>	757	45%		672	47%		513	39%	
<i>Must-Run and profitable</i>	721	43%		543	38%		718	55%	
Unprofitable (Must Run)	210	12%		213	15%		73	6%	
Merchants	101		\$12.16	39		\$7.50	38		\$18.37
Profitable Starts	101	100%		35	90%		38	100%	
<i>Offered Economically</i>	101	100%		29	74%		29	76%	
<i>Must-Run and profitable</i>	1	0%		6	15%		9	24%	
Unprofitable (Must Run)	0	0%		4	10%		0	0%	

R. Dispatch of Peaking Resources

Generator commitments in the real-time market often satisfy peak demand. Peaking resources typically account for a large share of real-time commitments because they are available on short notice and have attractive commitment-cost profiles (i.e., low startup costs and short startup and minimum-run times). These qualities make peaking resources good candidates to satisfy the system's incremental capacity needs. However, they generally have high incremental energy costs and often do not set the energy price because they are dispatched at their economic minimum level, causing them to run "out-of-merit" with an offer price higher than their LMP. When a peaking unit does not set the energy price or runs out of merit, it will not recover its startup and minimum generation costs. This revenue inadequacy results in real-time RSG payments.

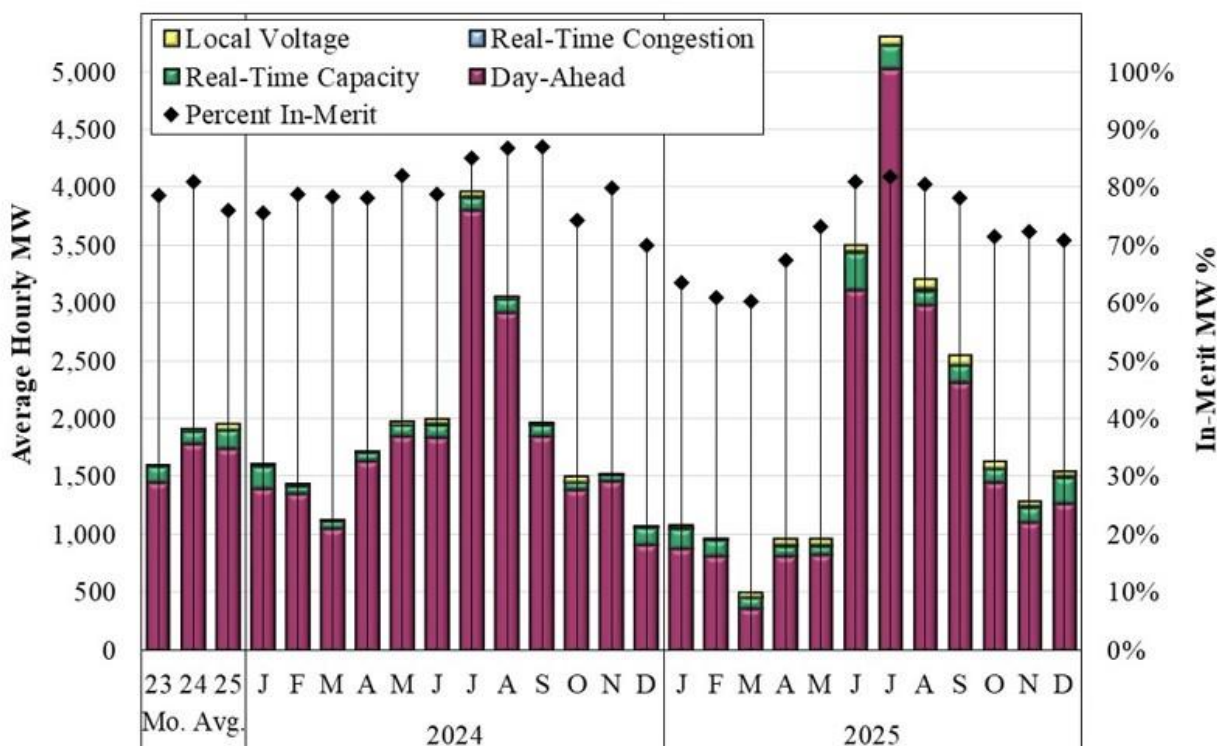
¹⁹ The resources' start-up costs are determined based on how long the resource has been offline – cold vs. hot start-up costs. The start-up costs are amortized over five days – a minimum typical cycle for coal resources.

MISO’s aggregate load peaks in the summer, so peaking-resource dispatch has the greatest impact during summer months, when system demand can at times require substantial commitments of these resources. Several other factors can also contribute to peaking-resource commitments, including day-ahead net scheduled load that is less than actual load, transmission congestion, wind forecasting errors, and changes in real-time NSI.

Figure A65: Dispatch of Peaking Resources

Figure A65 shows average hourly dispatch levels of peaking units in 2024 and 2025 and the consistency of peaking unit dispatch with market outcomes. It disaggregates the figure by the unit’s commitment reason and separately indicates the share of peaking resource output that is in merit order (i.e., the LMP exceeds its offer price).

Figure A65: Dispatch of Peaking Resources
By Commitment Reason, 2024–2025



S. Wind and Solar Generation

Wind generation in MISO has grown steadily since the markets began in 2005. Although wind generation promises substantial environmental benefit, its output is intermittent and presents unique operational and scheduling challenges.

Over 90 percent of MISO’s wind units are Dispatchable Intermittent Resources (DIR). DIRs can respond to dispatch instructions and can therefore set the real-time energy price. DIRs can submit offers in the day-ahead market, are eligible for all uplift payments, and are subject to typical operating requirements. For both DIR and non-DIR wind units, MISO uses short- and

long-term forecasts to estimate wind output. Because DIRs are prevalent, MISO rarely uses manual curtailments to ensure reliability. Wind resources can also sell capacity under Module E of the Tariff based on their contribution to satisfying MISO's planning requirements.²⁰

Table A12: Day-Ahead and Real-Time Wind and Solar Generation

Table A12 shows the hourly average real-time wind and solar generation scheduled in the day-ahead market. The second-to-last set of columns shows the top five percent of average hourly output by season, and the far-right columns show the average and absolute value of the real-time forecast error.

Table A12: Day-Ahead and Real-Time Wind and Solar Generation
2022–2025

	Nameplate Capacity	Avg. Output (GW)			RT Seasonal Avg. Output (GW)			RT Top 5% Hrly Avg. Output (GW)			2 Hr Forecast Error (%)	
		RT	DA	%	Jan.-Apr.	May-Aug.	Sep.-Dec.	Jan.-Apr.	May-Aug.	Sep.-Dec.	Avg. Error	Abs. Avg.
2025	49,538	14.6	12.7	-13.1	17.2	12.2	14.3	29.4	27.3	28.2	0.3%	5.6%
%*	13%	13%	11%		18%	16%	7%	19%	28%	14%		
2024	43,819	12.9	11.4	-11.6	14.6	10.6	13.5	24.8	21.3	24.7	-0.9%	5.6%
2023	35,608	11.1	9.8	-12.0	13.5	8.2	11.8	22.4	18.6	21.8	-1.2%	6.2%
2022	30,916	11.8	10.5	-10.8	14.0	9.1	12.3	21.9	18.8	21.9	-0.2%	6.1%

Note 1: % Change between 2024 and 2025.*

Wind suppliers often schedule less output in the day-ahead market than they produce in real time. Some suppliers' contracts and the financial risk of being allocated RSG costs when day-ahead wind output is over-forecasted contribute to this practice. Under-scheduling output in the day-ahead market can create price convergence issues and create uncertainty about the need to commit resources.

Net virtual suppliers partially address convergence issues by selling energy in the day-ahead market in place of wind suppliers. Because the most significant effect of day-ahead wind under-scheduling is on transmission flows and the associated congestion in the day-ahead and real-time markets, we evaluate the extent to which virtual transactions offset those flow effects.

We calculated the percentage of flows from wind units on every constraint in the day-ahead and real-time markets. We estimated profits from virtual positions on those constraints and aggregated them by year and monitored element. We identified constraints where wind-related flows exceeded 20 percent in either the day-ahead or real-time market and sorted them by virtual profitability.

Figure A66 and Table A13: Virtual Transaction Effects on Day-Ahead Constraints Affected by Wind Scheduling

Figure A66 shows the top 10 constraints identified in our analysis. The blue bars show the average day-ahead flow from wind generators, the red diamonds show the real-time equivalent,

²⁰ Capacity credits for wind resources are determined by evaluating a unit's performance during the peak hour of the relevant season of each of the prior 3 years' 8 highest-load days (24 hours per season). For the 2025–2026 Planning Year, the system-wide capacity credit for wind is 20.8 percent in the summer season, with individual credits ranging from 4 to 36 percent, and 29 percent in winter season, with individual credits ranging from 6 to 47 percent.

and a transparent green bar over each blue bar shows day-ahead virtual flow. These values are expressed as a percentage of the rating on the affected constraints. We masked the identity of the constraints in the figure.

Figure A66: Virtual Impacts on Top 10 Constraints Affected by Wind
2025

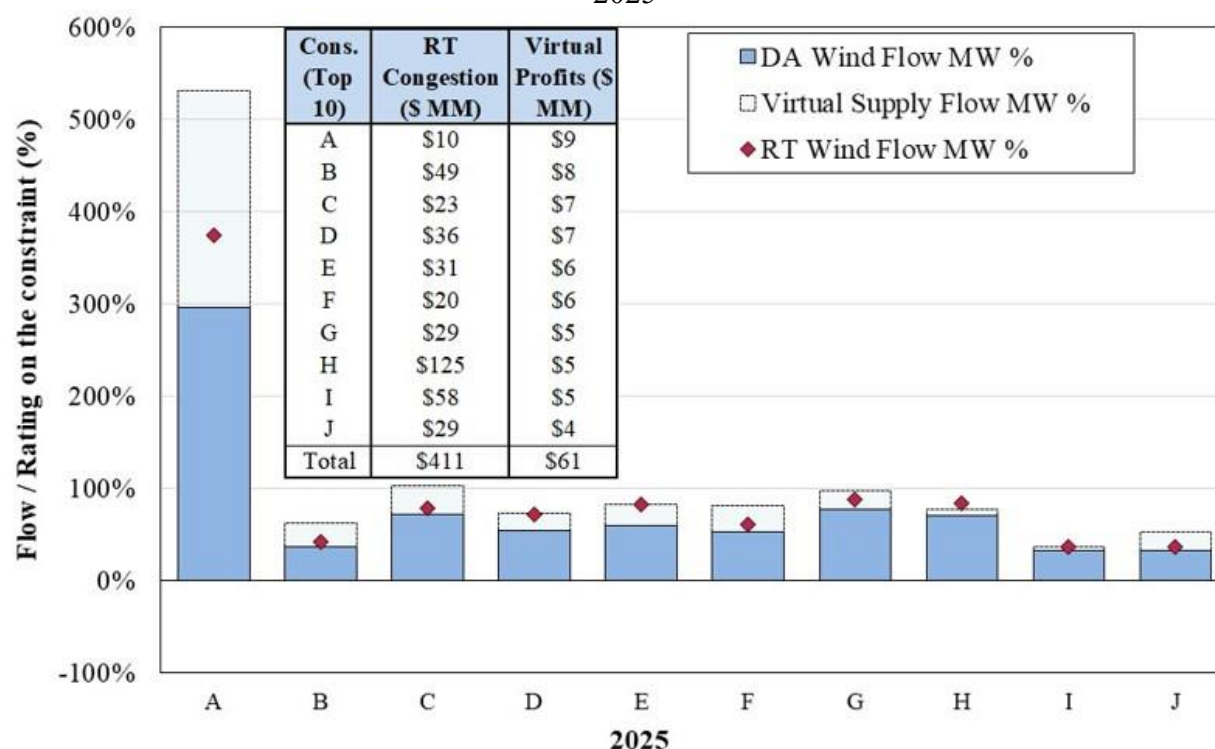


Table A13 shows the number of wind-impacted constraints we identified in each of six categories, the aggregate congestion associated with the constraints in each category, and the virtual profitability in each category.

Table A13: Aggregate Virtual Impacts on Constraints Affected by Wind
2025

Wind-Impacted Constraints Categories(2025)	Number of Constraints	RT Congestion (\$ MM)	Virtual Profitability (\$ MM)
All Wind-Impacted Constraints	399	\$1431	\$55
RT Wind Flow > DA Wind Flow	356	\$1371	\$48
DA Wind Flow > RT Wind Flow	43	\$60	\$7
RT Wind Flow > DA Wind Flow and Virtual Supply > 0	301	\$1133	\$48
RT Wind Flow > DA Wind Flow and Virtual Supply < 0	55	\$238	\$0
DA Wind Flow > RT Wind Flow and Virtual Supply > 0	0	\$0	\$0

Figure A67: Generation Wind Over-Forecasting Levels

In 2016, we identified significant concerns with certain wind resources that frequently and substantially over-forecasted their wind output. These forecasts are important because MISO

uses them to establish wind resources' economic maximums in the real-time energy market. Because wind resources typically offer at lower prices than other resources, their forecasted output also typically matches their MISO dispatch instructions, absent congestion. Dispatch deviations arise because an over-forecasted resource produces less than its dispatch instruction. Figure A67 shows the monthly absolute average forecast errors for wind resources in the bars and the average forecast error as a line on the right axis in 2024 and 2025. MISO changed its forecasting methodology in early 2020, significantly reducing both absolute average and average forecast errors.

**Figure A67: Generation Wind Over-Forecasting Levels
2024-2025**

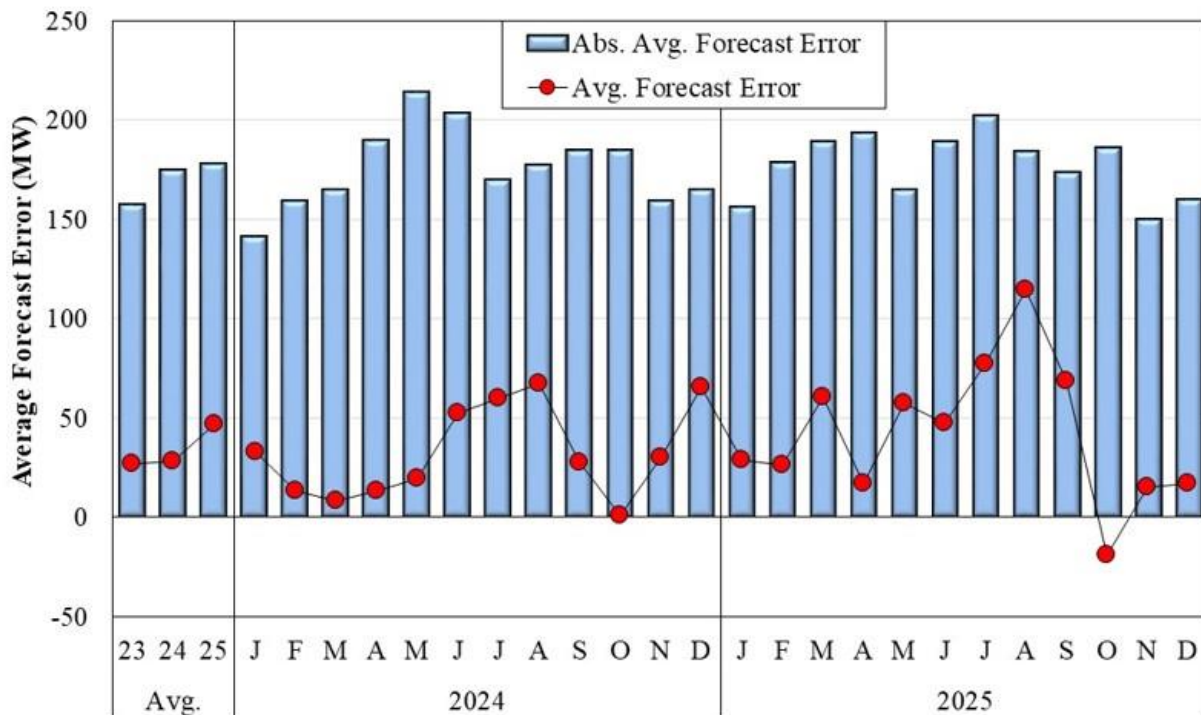


Figure A68: Wind Forecast Methodology Improvement

Real-time wind forecasts are important because MISO uses them to establish wind resources' economic maximums in the real-time market. MISO's settlement rules incentivize participants to use MISO's forecast, and most wind resources do so. MISO's near-term forecast is primarily a "persistence" forecast that assumes future wind resource output will match the most recent output observation.

We developed a persistence-based forecast methodology that also incorporates the recent direction of output changes. The IMM Forecast uses a trended-persistence approach based on the prior 10 minutes of actual output to project output 10 minutes into the future. The forecasted change is limited to half of the headroom (capacity minus current output) for upward changes and half of the current output for downward changes. Figure A68 shows the results of the IMM's approach compared to the incumbent vendor forecast.

Figure A68: Wind Forecast Methodology Improvement

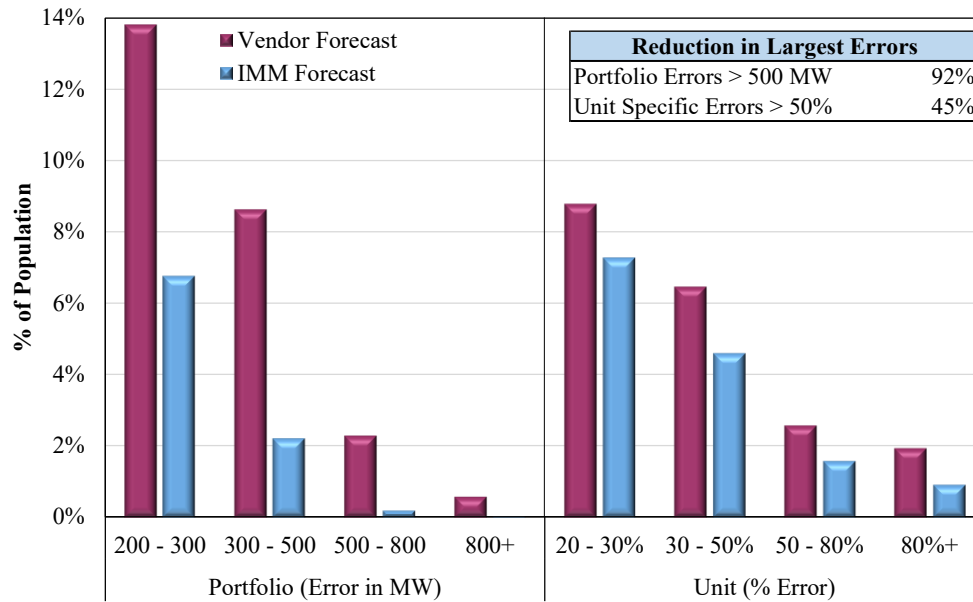


Figure A69: Wind Generation Volatility

Wind output can be highly variable and must be managed through curtailment, redispatch of other resources, or commitment of peaking resources. Figure A69 summarizes the monthly wind-output volatility for 2024 and 2025 by showing: (a) the average absolute value of the 60-minute change in wind generation in the blue line; (b) the largest five percent of hourly decreases in wind output in the blue bars; and (3) the maximum hourly decrease in each month in the drop lines. We exclude changes in wind output from economic curtailments from this analysis.

Figure A69: Wind Generation Volatility
2024–2025

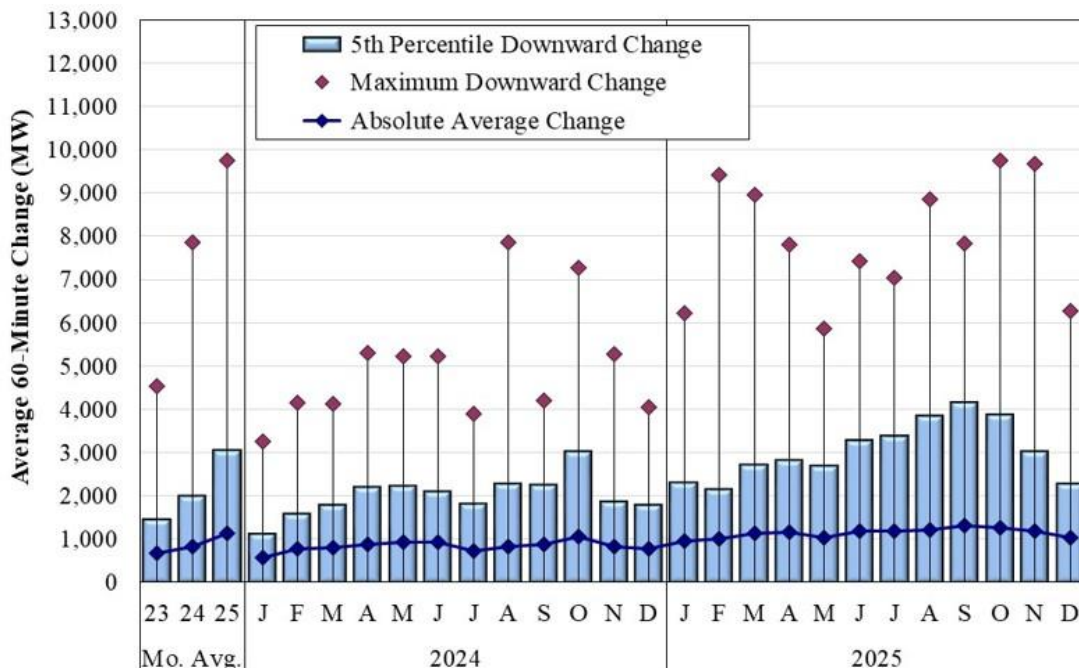
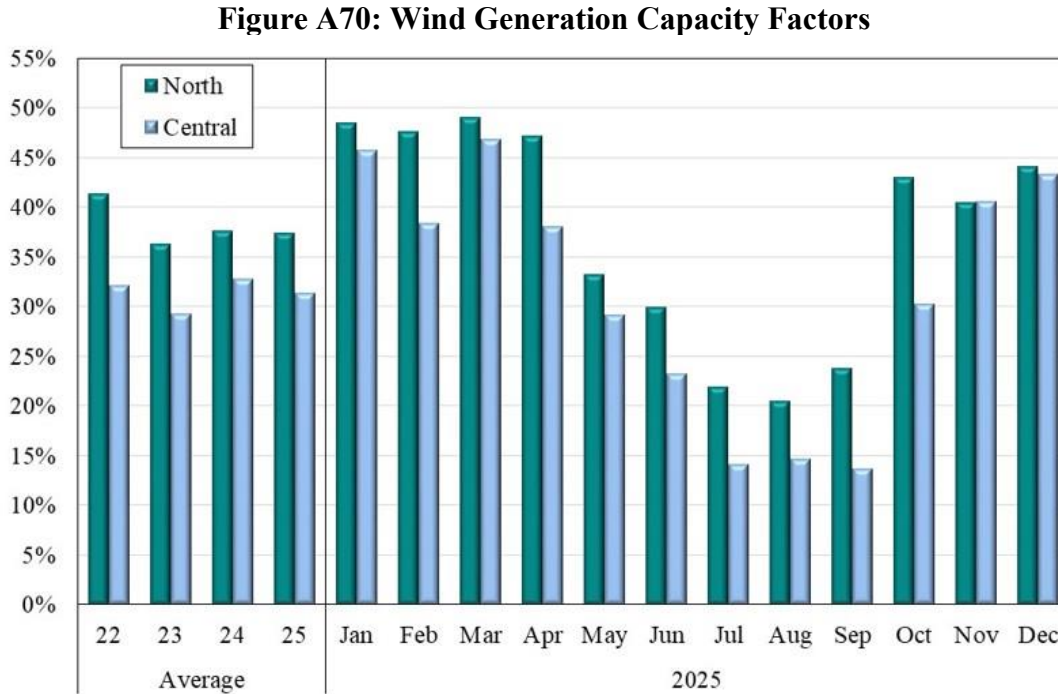


Figure A70: Wind Generation Capacity Factors

Wind capacity factors measure actual output as a percentage of nameplate capacity and can vary by season and location. Figure A70 shows average hourly wind capacity factors by month for two MISO Coordination regions (North and Central).



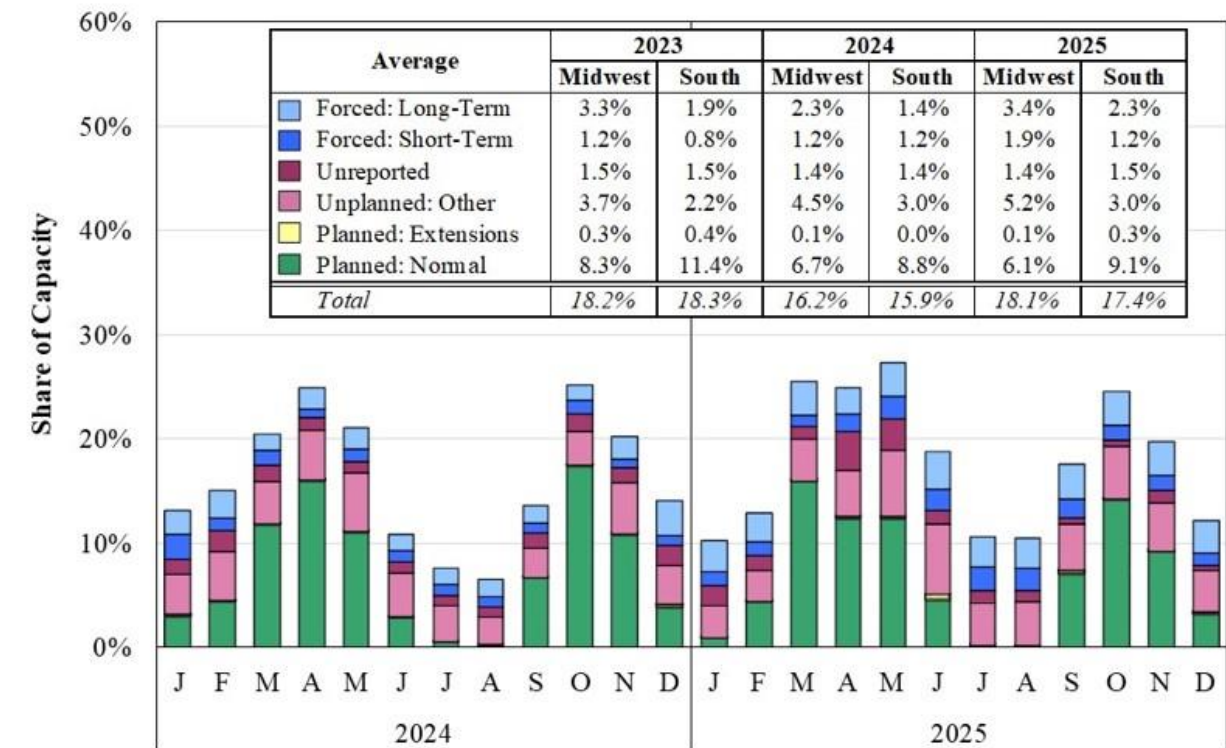
T. Outage Scheduling

Figure A71: MISO Outages

Figure A71 shows the monthly average planned and unplanned generator outage rates for the two most recent years and annual averages for the last three years. It includes only full outages, not partial outages or deratings. The figure also distinguishes between short-term unplanned outages, which last fewer than seven days, and long-term unplanned outages, which last seven days or longer. In addition, it distinguishes between normal planned outages and short-notice planned outages scheduled within seven days of the actual outage start. Planned outages are often scheduled in low-load periods when economics favor maintenance, although short-notice planned outages and short-term unplanned outages often result from emergent operating problems.

Short-notice and short-term outages warrant review because they are more likely to reflect attempts by participants to physically withhold supply from the market. It costs less to withhold resources for short periods when conditions are tight than to take a long-term outage. Section VIII.F shows market power concerns related to potential physical withholding.

Figure A71: Generation Outages
2024–2025



V. TRANSMISSION CONGESTION AND FTR MARKETS

Managing transmission congestion is one of MISO’s most important roles. MISO monitors thousands of potential network constraints across its system and manages network flows by altering resource dispatch to avoid overloading them. This process establishes efficient, location-specific prices that represent the marginal cost of serving load at each location.

Transmission congestion arises when limited transmission capability prevents MISO from fully dispatching the lowest-cost resources. As a result, MISO must dispatch higher-cost units instead of lower-cost units to avoid overloading transmission facilities. In LMP markets, the congestion component of locational prices reflects this generation re-dispatch, or “out-of-merit,” cost. The congestion component of LMPs can vary substantially across the system, causing higher LMPs in “congested” areas.

These congestion-related price signals are valuable not only because they induce generation resources to produce at levels that manage network congestion efficiently, but also because they provide longer-term economic signals that support efficient investment in and maintenance of generation and transmission facilities.

A. Real-Time Value of Congestion

This subsection reviews the value of real-time congestion, which differs from the congestion revenues MISO collects. The value of congestion equals the marginal value, or shadow price, of the constraint times the power flow over the constraint. If a constraint is not binding, the shadow price and congestion value are zero. This means the constraint does not affect the economic dispatch or increase production costs. MISO does not collect the full value of congestion on its system for at least two reasons.

First, the congestion value is based on the total flow over the constraint, but MISO settles only part of the flow on its constraints. Generators serving loads outside MISO contribute to flows over MISO’s system, known as “loop flows”, and do not pay MISO for their congestion value. In addition, PJM and SPP have entitlements to flow power over MISO’s system, and their real-time flows up to those entitlement levels do not settle with MISO.

Second, most flows are settled through the day-ahead market. Once a participant has paid for flows over a constraint in the day-ahead market, it does not have to pay again in the real-time market, which settles only deviations from the day-ahead market. Therefore, when day-ahead prices do not foresee or fully anticipate congestion, MISO collects less congestion revenue in the day-ahead market than the real-time value of congestion on its system.

Figure A72: Value of Real-Time Congestion by Coordination Region

Figure A72 shows the total monthly value of real-time congestion by MISO’s Reliability Coordination regions in 2024 and 2025. The bars in the left panel show the average monthly value for the past three years.

Figure A72: Value of Real-Time Congestion by Coordination Region
2024–2025

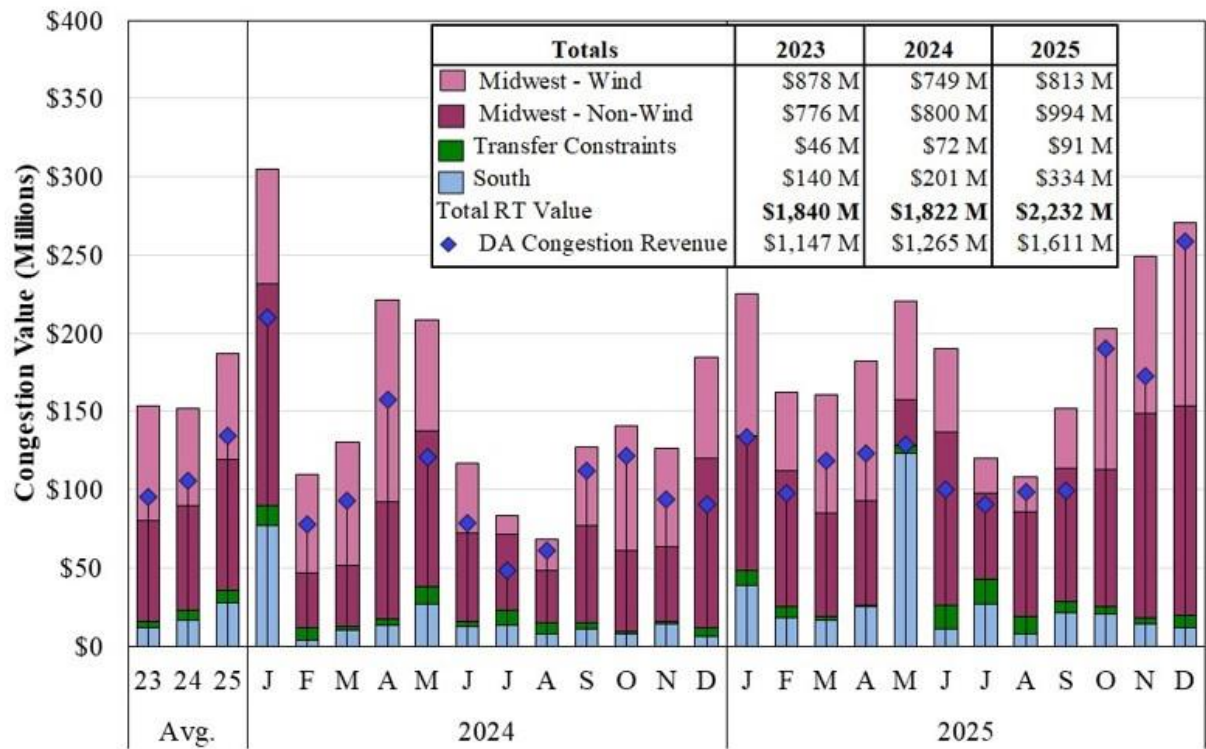


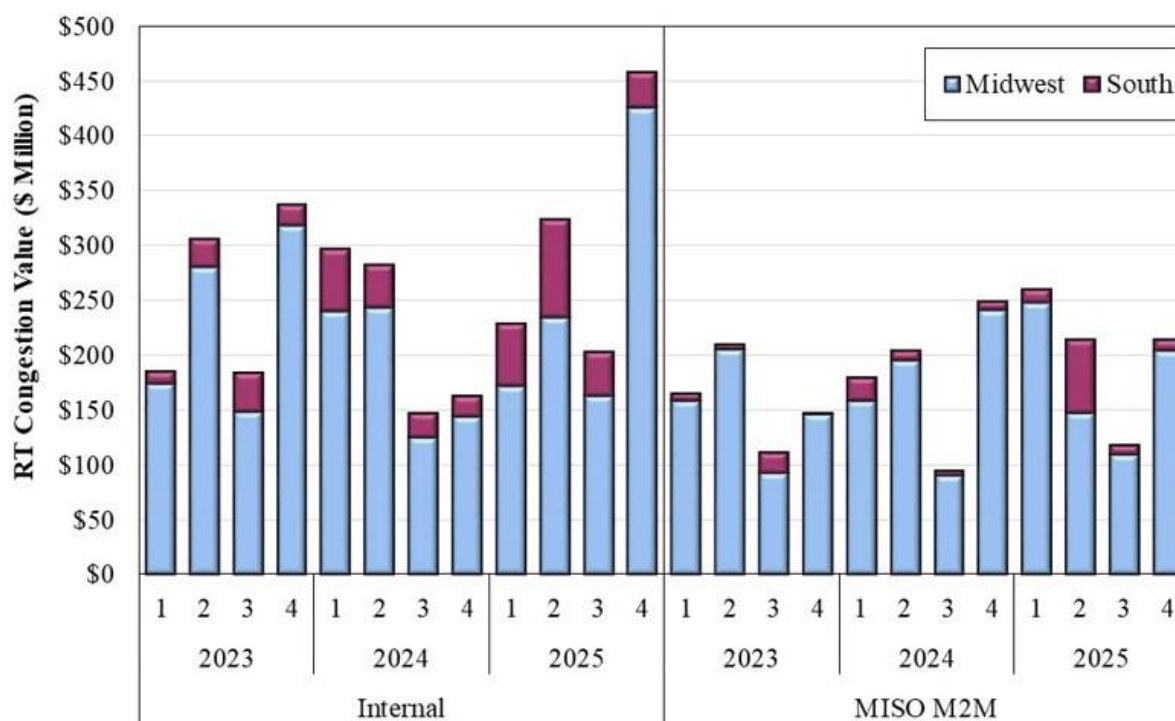
Figure A73: Value of Real-Time Congestion by Type of Constraint

Figure A73 disaggregates the real-time congestion value by MISO subregion and by two types of constraints to better identify its drivers:

- Internal Constraints: Constraints internal to MISO for which MISO is the Reliability Coordinator and that are not coordinated with PJM or SPP.
- MISO market-to-market (M2M) Constraints: MISO constraints that MISO coordinates with SPP and PJM through the M2M process.

The flow on PJM and SPP M2M constraints is limited to the MISO market flow, which we use to measure congestion value. Market flow is MISO’s flow on the constraints in MISO’s dispatch model and does not represent the total flow on these constraints. By contrast, the internal constraints in the MISO dispatch model include total flow.

Figure A73: Value of Real-Time Congestion by Type of Constraint
By Quarter, 2023–2025



B. Day-Ahead Congestion and FTR Funding

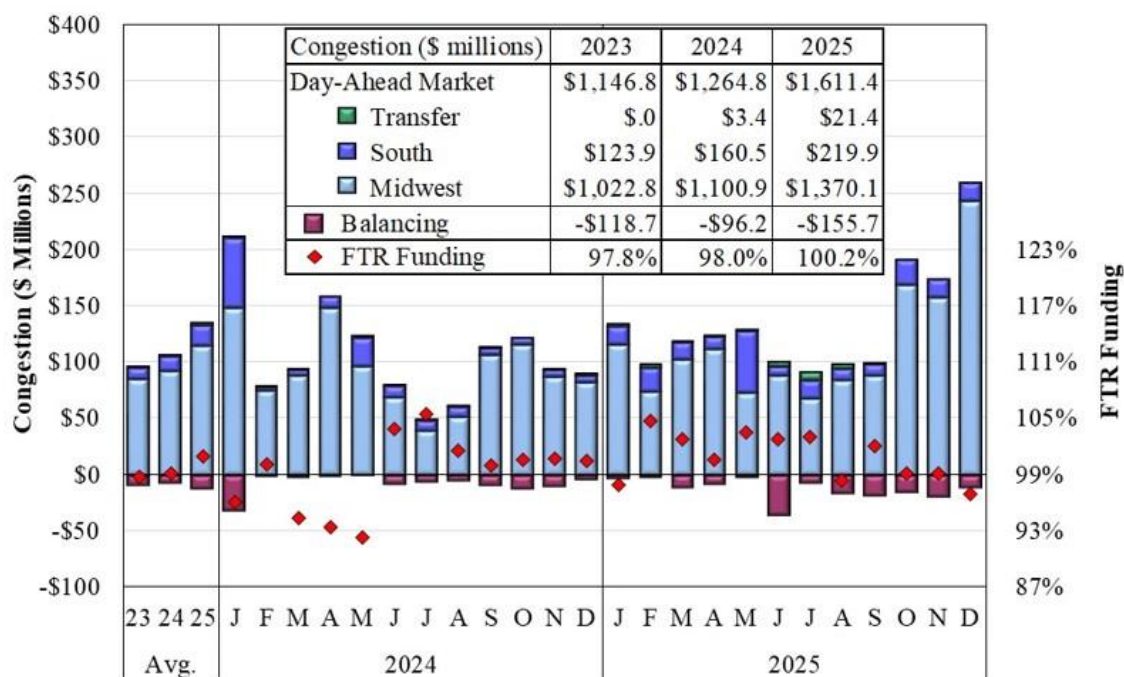
MISO’s day-ahead energy market is designed to send accurate and transparent locational price signals that reflect congestion and losses on the network. MISO collects congestion revenue in the day-ahead market based on the differences in the LMPs at locations where energy is scheduled to be produced and consumed.

MISO pays the resulting congestion revenue to the FTR holders. FTRs represent the economic property rights of the transmission system and entitle the holder to the day-ahead congestion revenues between two points on the network. MISO allocates a large share of the value of these rights to market participants. It sells the residual unallocated FTR capability in the FTR markets, and the resulting revenues help recover network costs. FTRs allow market participants to hedge day-ahead congestion costs. If the FTRs issued by MISO are physically feasible, meaning they do not imply more flows over the network than the limits in the day-ahead market, MISO will always collect enough congestion revenue through its day-ahead market to “fully fund” the FTRs—to pay FTR holders 100 percent of the FTR entitlement.

Figure A74: Day-Ahead and Balancing Congestion and FTR Funding

Figure A74 shows the total day-ahead congestion revenues for constraints in MISO Midwest, MISO South, and on the transfer constraints between MISO Midwest and MISO South for 2024 and 2025. It also shows balancing congestion revenue (net congestion collections in real time) and the FTR funding level.

Figure A74: Day-Ahead and Balancing Congestion and FTR Funding
2024–2025



An FTR is a forward purchase of day-ahead congestion costs that allows participants to manage day-ahead congestion risk. Because transmission customers pay the embedded costs of the system, they are entitled to the system’s economic property rights. MISO allocates these property rights by assigning Auction Revenue Rights (ARRs) to transmission customers based on their historical network usage, load, and generating resources. ARRs are a MW value defined between two locations on the network. They give customers the right to receive the FTR revenues MISO collects when it sells FTRs that correspond to the ARRs. Customers can also convert their ARRs directly into FTRs.

MISO must pay FTR holders the FTR quantity times the per-unit congestion cost between the FTR source and sink.²¹ Congestion revenues from MISO’s day-ahead market fund these FTR obligations. Surpluses and shortfalls are limited when participants hold FTR portfolios consistent with network capability. Shortfalls or surpluses can occur when MISO sells FTRs that reflect network capability different from what is available in the day-ahead market. Reasons for differences between FTR capability and day-ahead capability include:

- Loop flows caused by generators and loads outside the MISO region;²² and
- Transmission outages or other factors that cause system capability modeled in the day-ahead market to differ from capability assumed when FTRs were allocated or sold.

²¹ An FTR obligation can be in the counter-flow direction and can require a payment from the FTR holder.

²² “Loop Flows” cannot be directly calculated and, in this context, would be measured as real-time flows less the calculated real-time market flows from PJM, SPP, and the MISO commercial flows (which include MISO market flows and the impacts of physical transactions). For example, when Southern Company generation serves its own load, some of this would flow over the MISO transmission system and this would be “loop flow.” The day-ahead model includes assumptions on loop flows that are anticipated to occur in real time.

Transactions that cause unanticipated loop flows are a problem because MISO collects no congestion revenue from them. If MISO allocates FTRs for the full capability of its system, loop flows can create an FTR revenue shortfall because MISO participants who pay congestion charges use only part of the network.

Each month, MISO funds FTRs by applying surplus revenues from overfunded hours *pro rata* to shortfalls in other hours. Monthly congestion revenue surpluses accumulate until year-end, when MISO prorates them to reduce any remaining FTR shortfalls. MISO has continued to improve the FTR and ARR allocation processes.

Figure A75: FTR Funding by Control Area

At an aggregate level, MISO's FTRs were fully funded in 2025. However, examining funding in more detail helps identify inconsistencies between the FTR market and the day-ahead market. Funding by Local Balancing Authority (LBA) can also illuminate potential cost-shifting among participants.

Figure A75 shows monthly FTR surpluses and shortfalls by LBA for 2025 in both dollars and percentage terms. The LBAs are masked with sequential letters. The constraints in each LBA include all internal and MISO-coordinated M2M constraints. The coordinating RTO summarizes external M2M constraints.

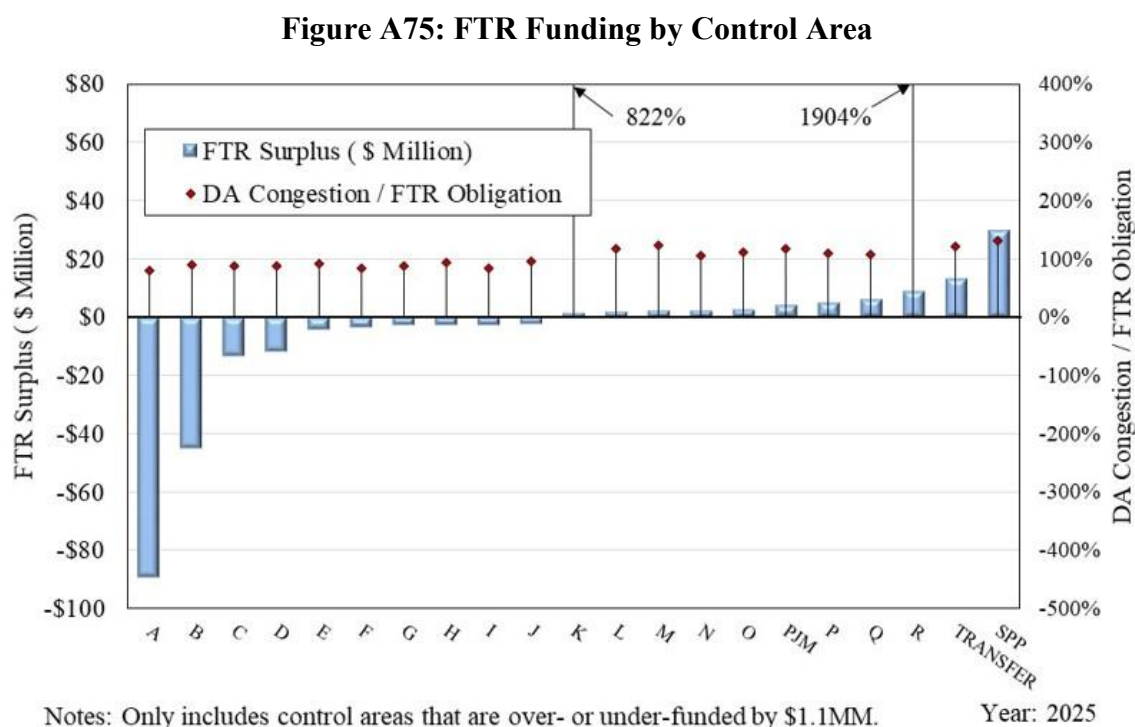


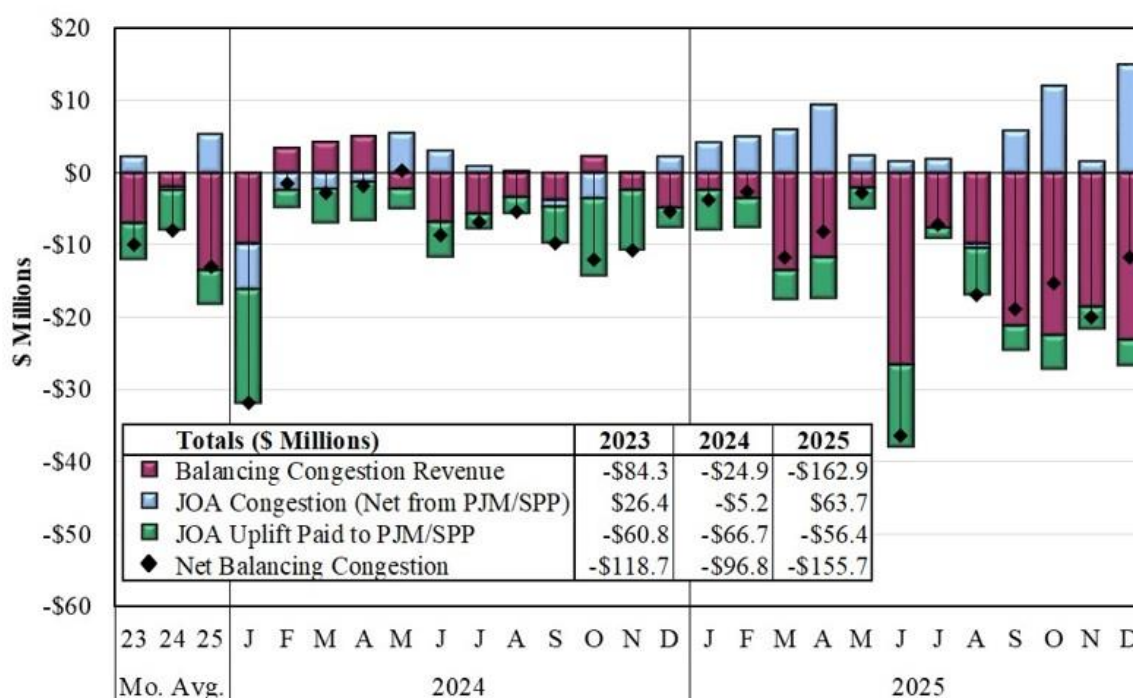
Figure A76: Balancing Congestion Revenues and Costs

Balancing congestion revenues are congestion collections in the real-time market based on deviations from day-ahead congestion outcomes. The magnitude of balancing revenues should be small if the day-ahead market accurately forecasts the real-time network capabilities. However,

balancing congestion revenue shortfalls occur when the day-ahead model is not fully consistent with the real-time network topology. For example, if MISO does not model a constraint in the day-ahead market and it binds in real time, MISO can accumulate substantial negative balancing congestion costs. In that case, day-ahead scheduled flows over the constraint can exceed the real-time limit. MISO must collect the costs to “buy back” the day-ahead flows, or balancing congestion costs, through an uplift charge to its customers.

Figure A76 disaggregates balancing congestion revenues into (1) the real-time congestion revenues (costs) collected when MISO must increase or reduce flows over binding transmission constraints and (2) the M2M payments made by or to PJM and SPP under the Joint Operating Agreements (JOAs). For example, when PJM exceeds its flow entitlement on a MISO-managed constraint, MISO will re-dispatch to reduce its flow, generating a cost shown as negative in the figure. PJM’s payment to MISO for this excess flow appears as positive revenue to MISO. We also include JOA uplift in real-time balancing congestion costs. JOA uplift results when MISO exceeds its Firm Flow Entitlement (FFE) on PJM M2M constraints and must buy that excess back from PJM at PJM’s shadow price. Like other net balancing congestion costs, JOA uplift is part of the revenue neutrality uplift costs collected from load and exports.

Figure A76: Balancing Congestion Revenues and Costs
2024–2025



C. FTR Market Performance

Because an FTR represents a forward purchase of day-ahead congestion costs, FTR markets perform well when FTR prices accurately reflect the expected value of day-ahead congestion. When this occurs, FTR profits are low because they equal the FTR price minus the day-ahead congestion payments. However, even if FTR prices represent a reasonable expectation of

congestion, several factors may cause actual congestion to be much higher or lower than the values established in the FTR markets. MISO currently runs the FTR market in two timeframes: an annual auction for the June to May planning year and the MPMA for the current and future months. The MPMA facilitates FTR trading for future months or seasons remaining in the planning year. Monthly auctions sell residual transmission capacity not sold in the seasonal auction. MISO also facilitates bilateral FTR trades in the monthly FTR auctions.

Figure A77: FTR Profits and Profitability

Figure A77 evaluates the profitability of these auctions by showing the seasonal profits for FTRs sold in each market. We calculate the values seasonally even though the FTRs are sold for one year, one season, or one month. In this figure, the “Monthly” values are the prompt month in the MPMA, while the “MPMA” values are for future months and seasons remaining in the planning year.

Figure A77: FTR Profits and Profitability
2024–2025

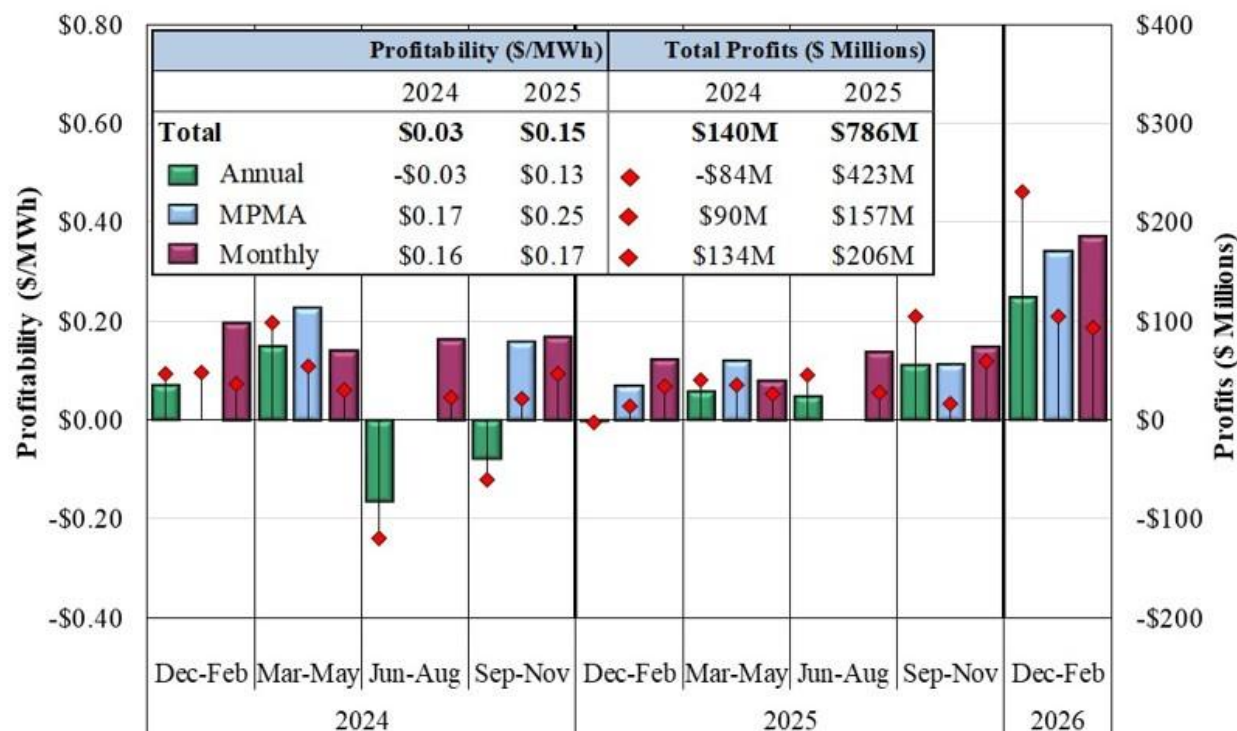


Figure A78 to Figure A80: FTR Profitability

The next three figures show the profitability of FTRs purchased in the annual, seasonal, and monthly auctions from 2023 to 2025. The bottom panel shows total profits and losses, while the top panel shows profits and losses per MWh. The results include both purchased and sold FTRs, with sold FTRs netted against purchased FTRs. For example, if an FTR purchased in round one of the annual auction is sold in round two, the purchase and sale net to zero.

Figure A78: FTR Profitability
2023–2025: Annual Auction

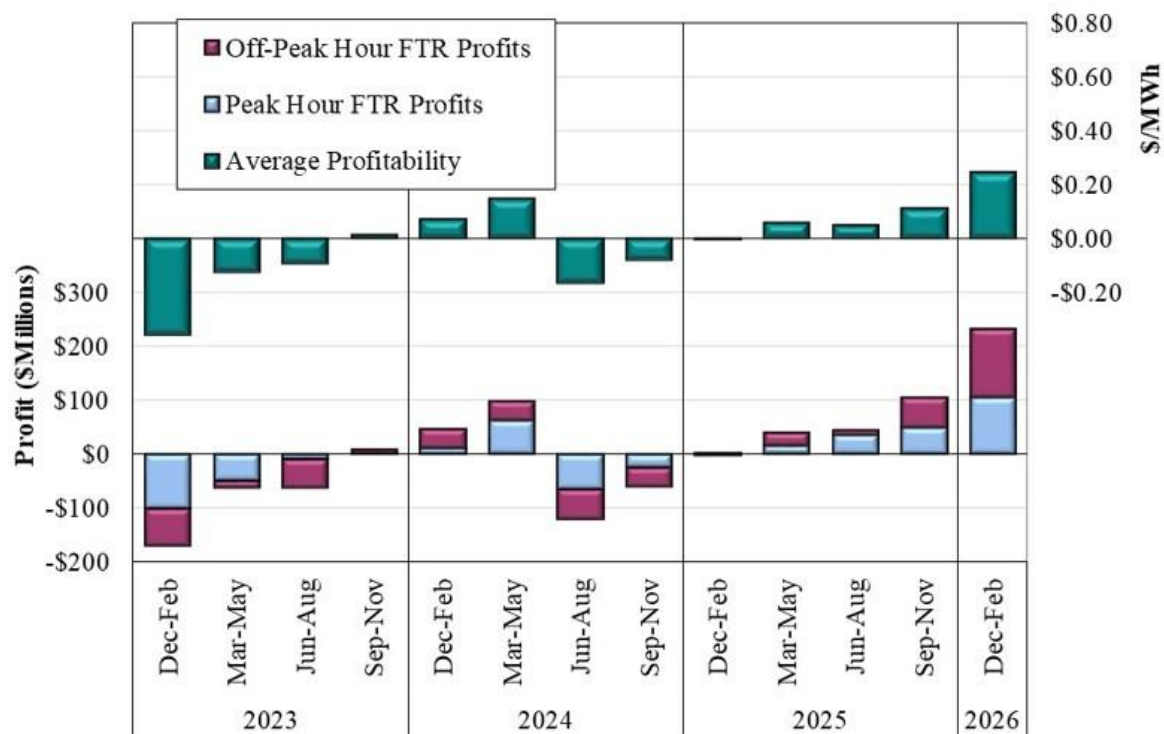


Figure A79: FTR Profitability
2024–2025: Monthly Auction

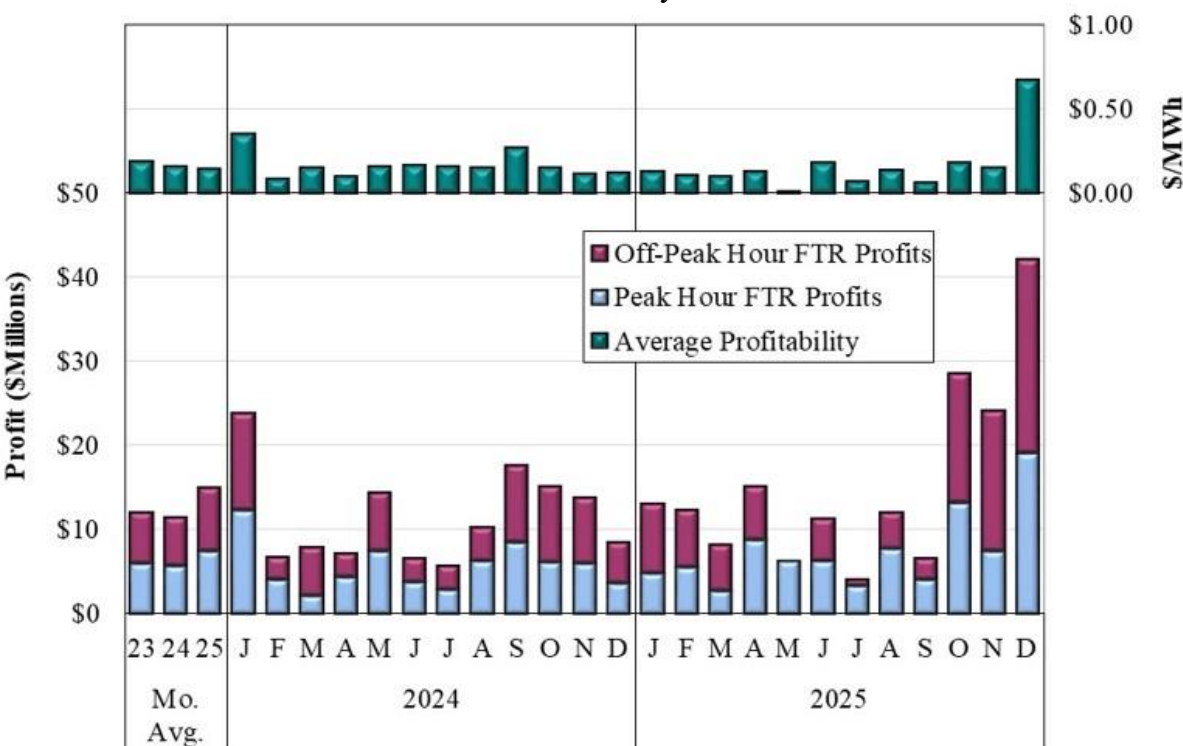


Figure A80: FTR Profitability
2023–2025 Seasonal Auction MPMA

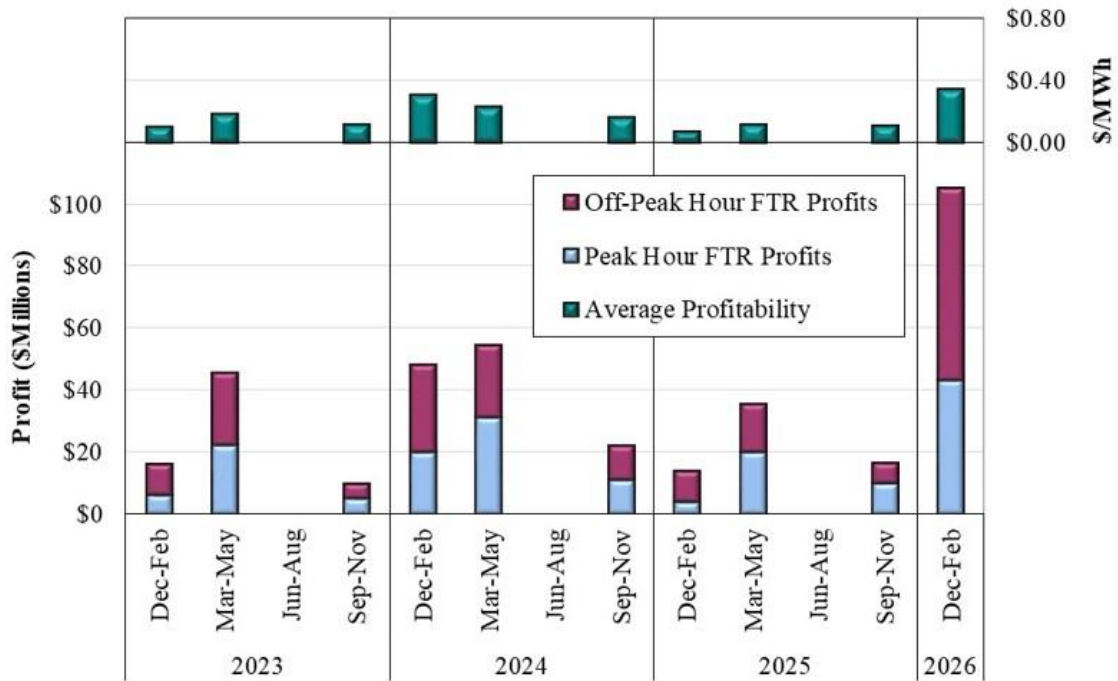


Figure A81 to Figure A92: Comparison of FTR Auction Prices and Congestion Values

The next 12 figures compare monthly FTR auction revenues with day-ahead FTR obligations at four Midwest locations and three South locations in peak and off-peak hours.

Figure A81: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2024–2025: Off-Peak Hours

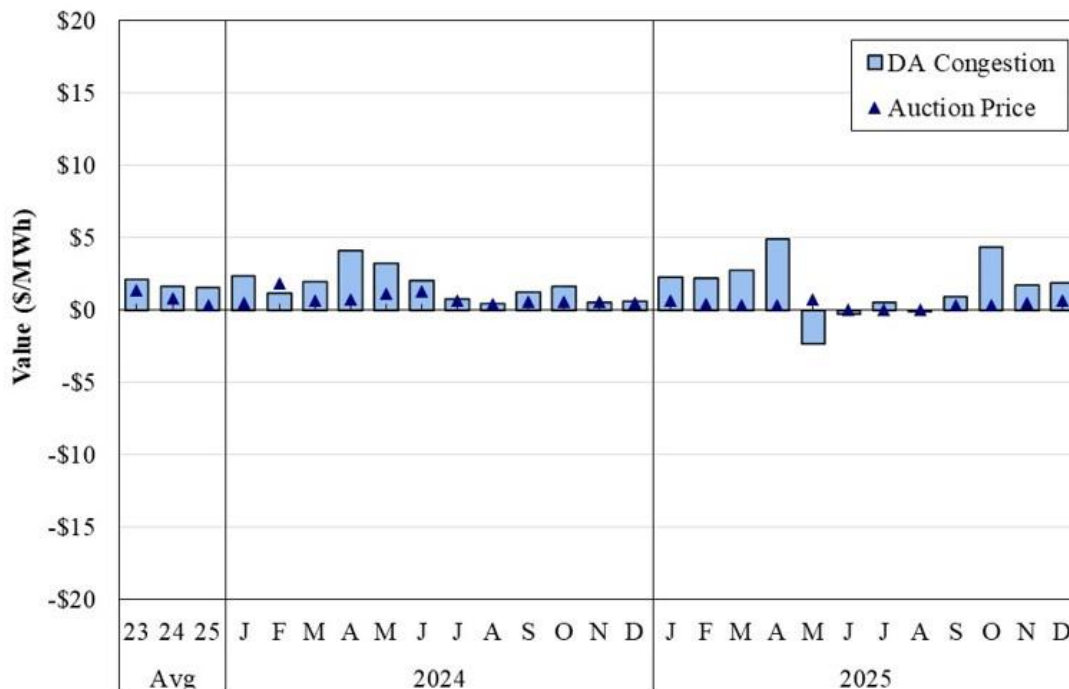


Figure A82: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2024–2025: Peak Hours

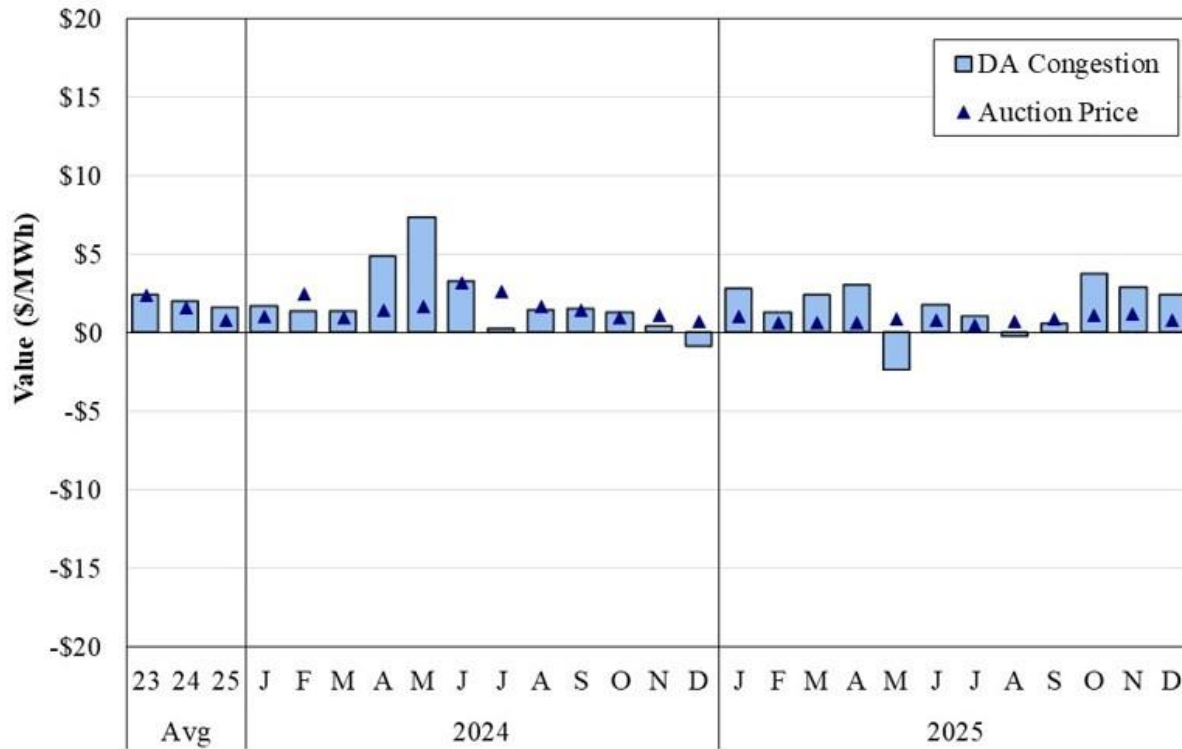


Figure A83: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2024–2025: Off-Peak Hours

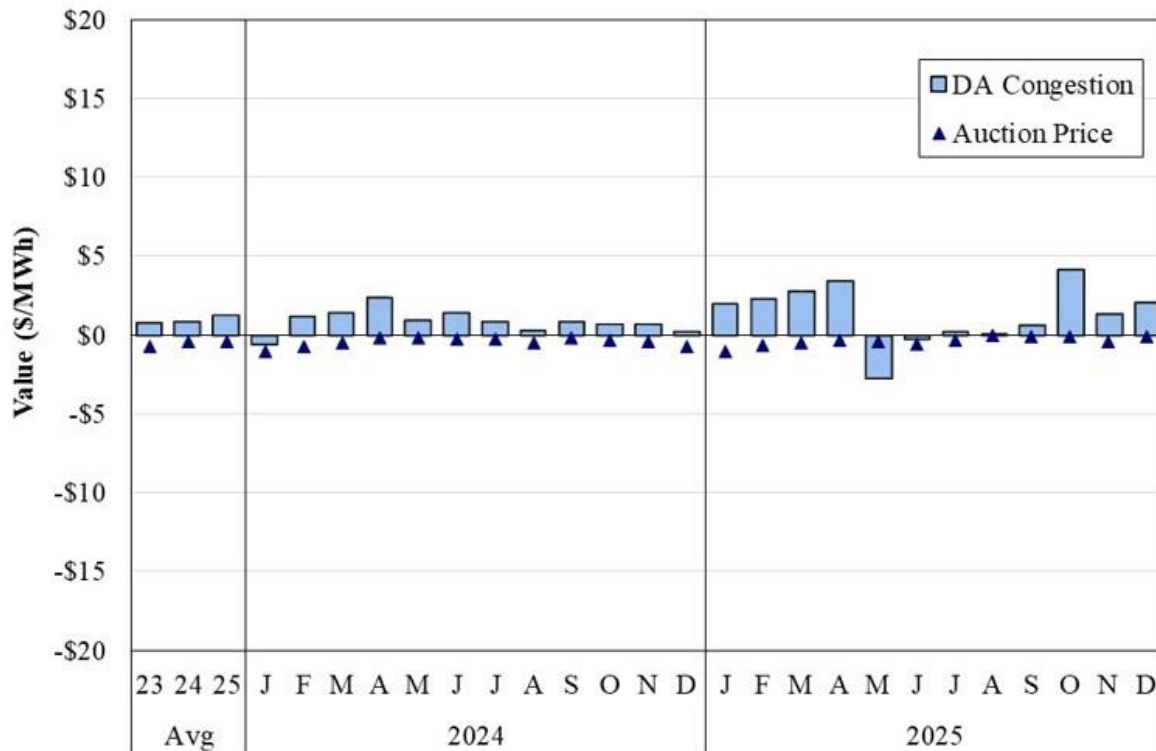


Figure A84: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2024–2025: Peak Hours

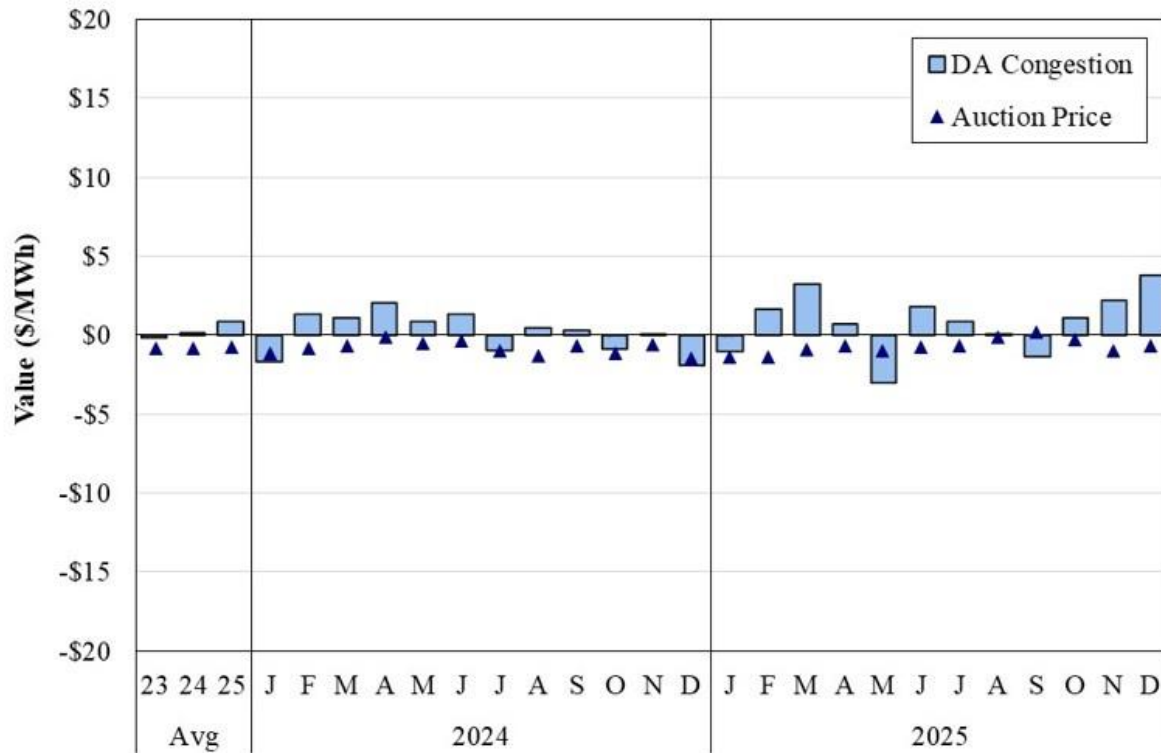


Figure A85: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2024–2025: Off-Peak Hours

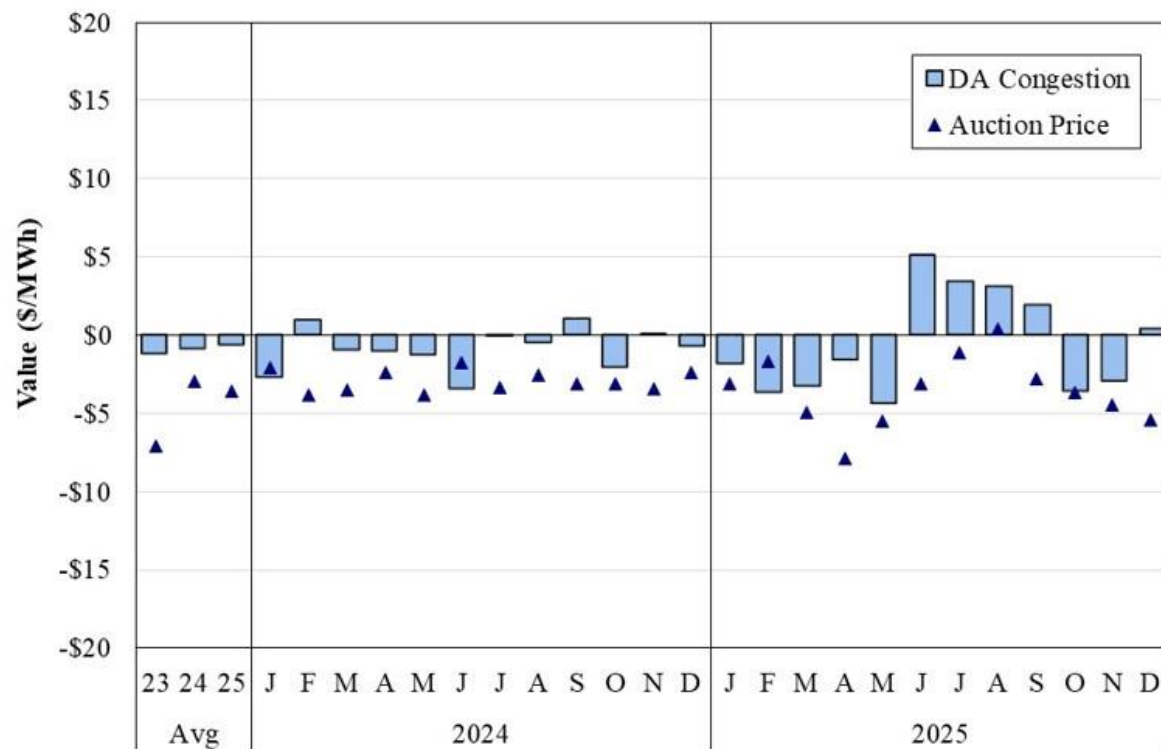


Figure A86: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2024–2025: Peak Hours

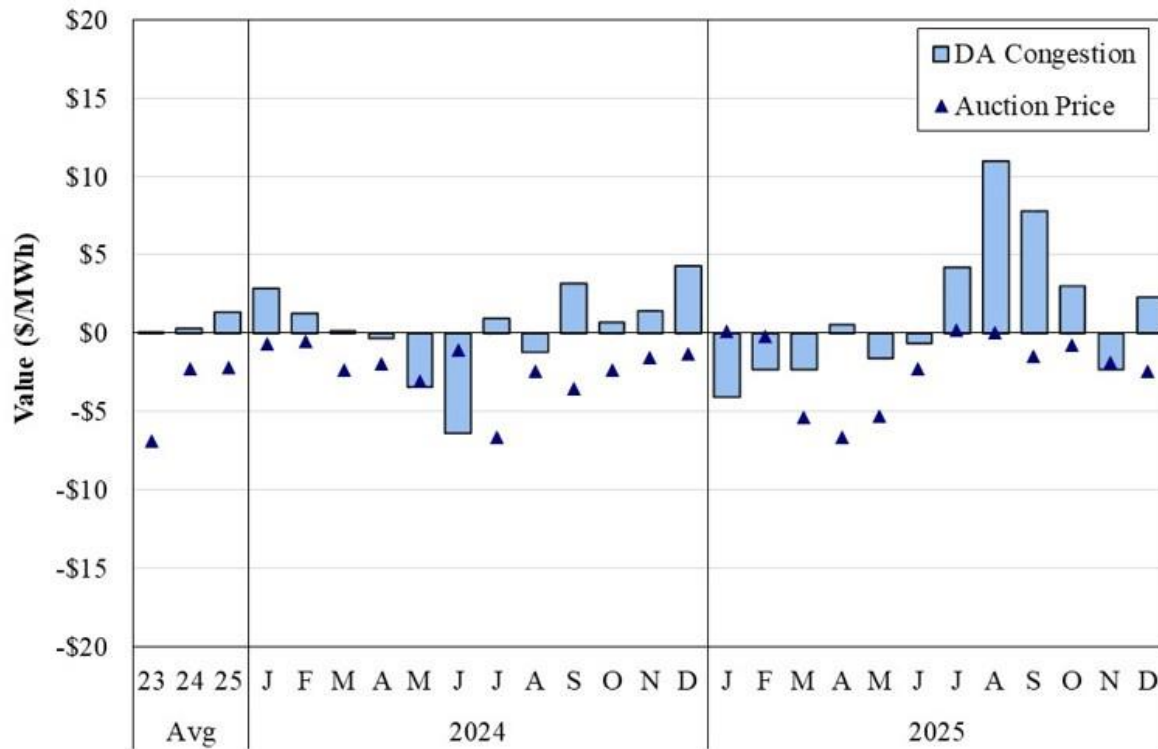


Figure A87: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2024–2025: Off-Peak Hours

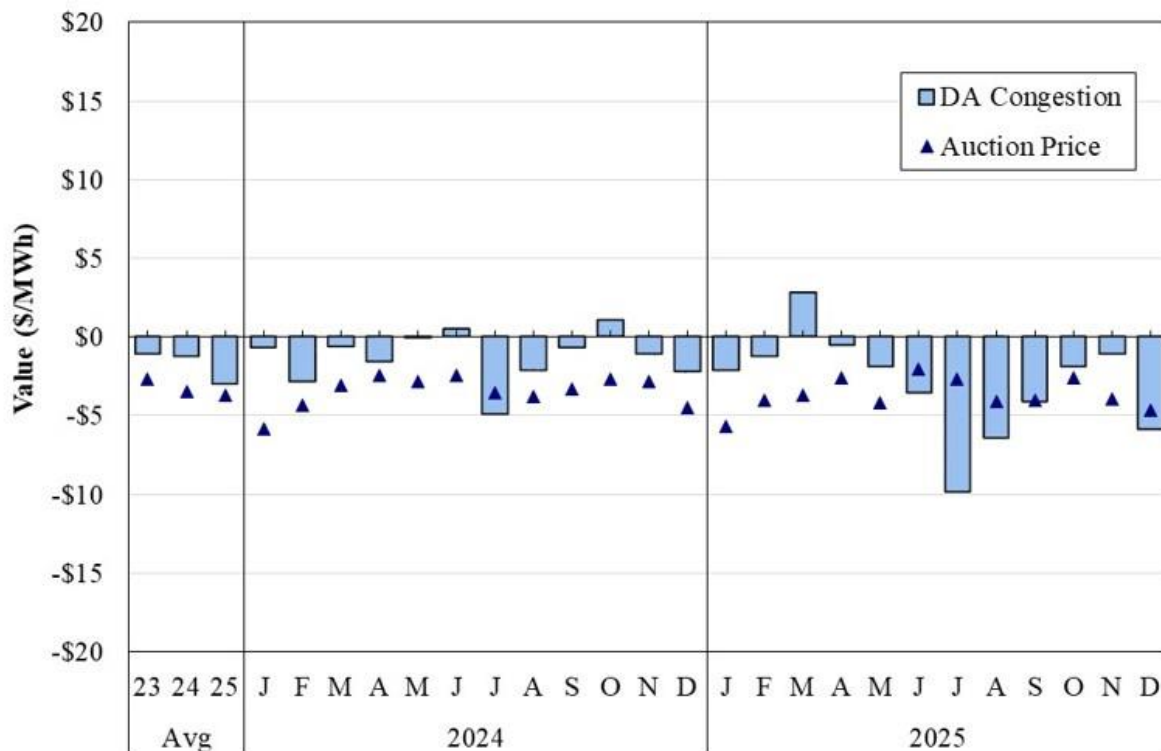


Figure A88: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2024–2025: Peak Hours

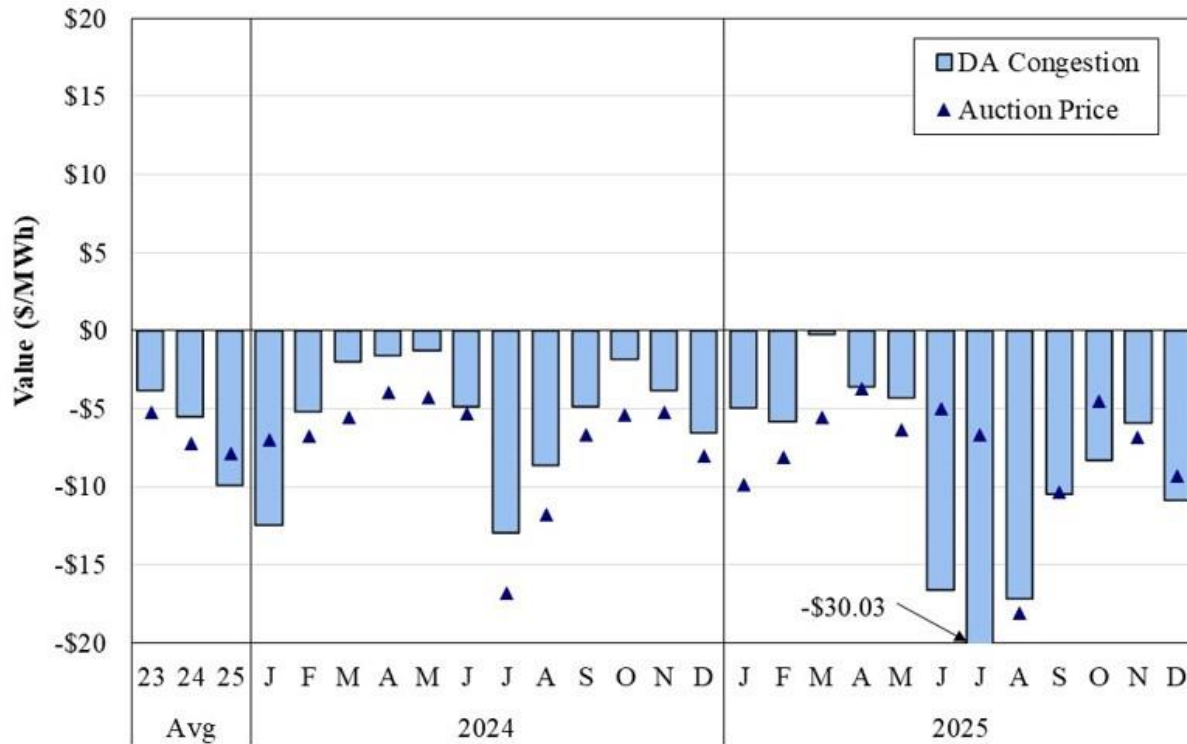


Figure A89: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2024–2025: Off-Peak Hours

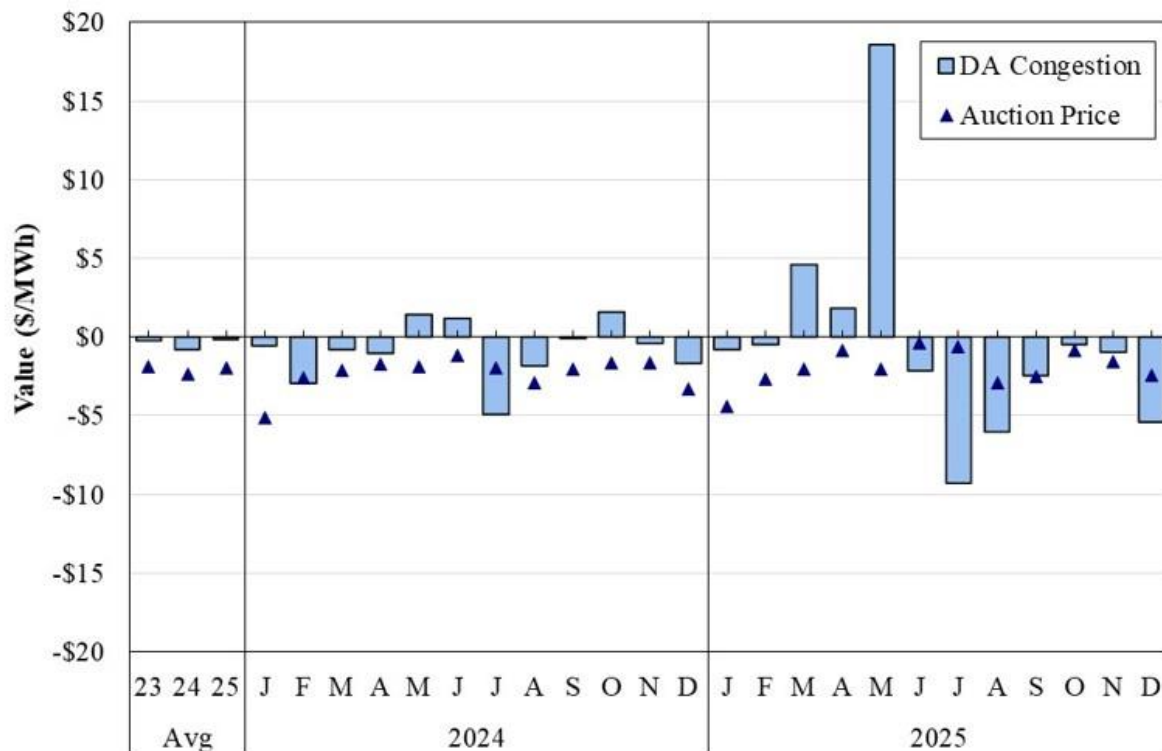


Figure A90: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2024–2025: Peak Hours

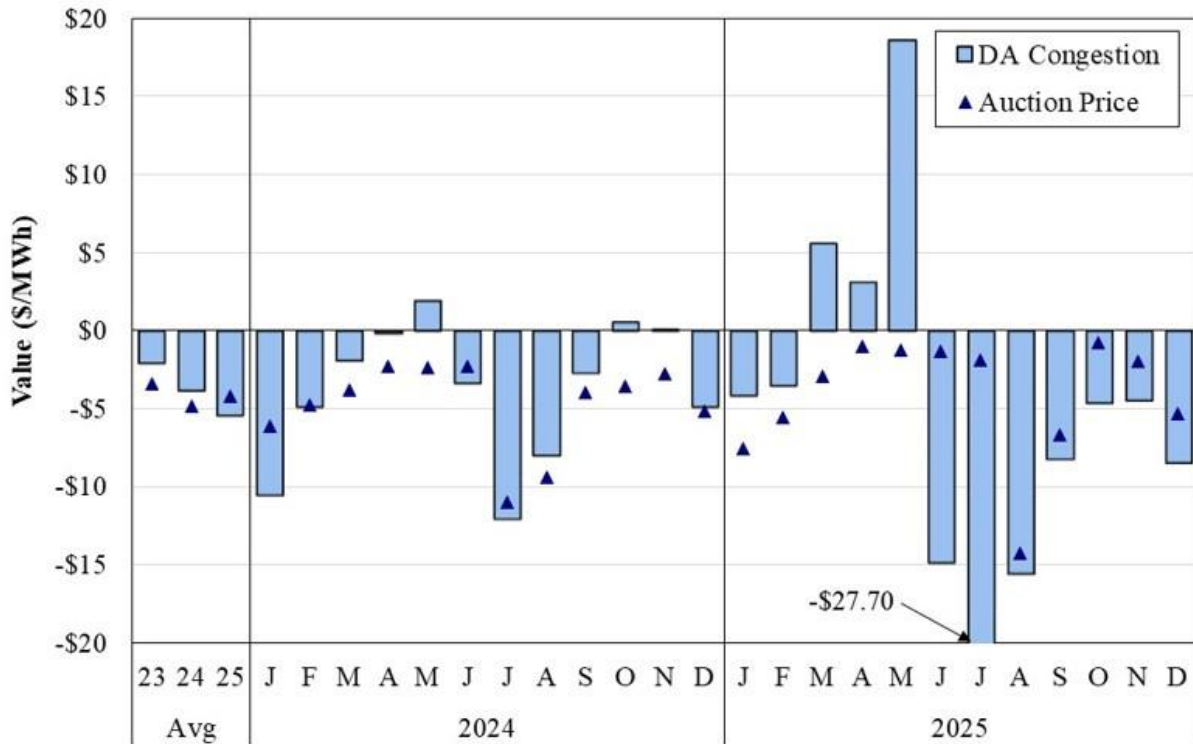


Figure A91: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2024–2025: Off-Peak Hours

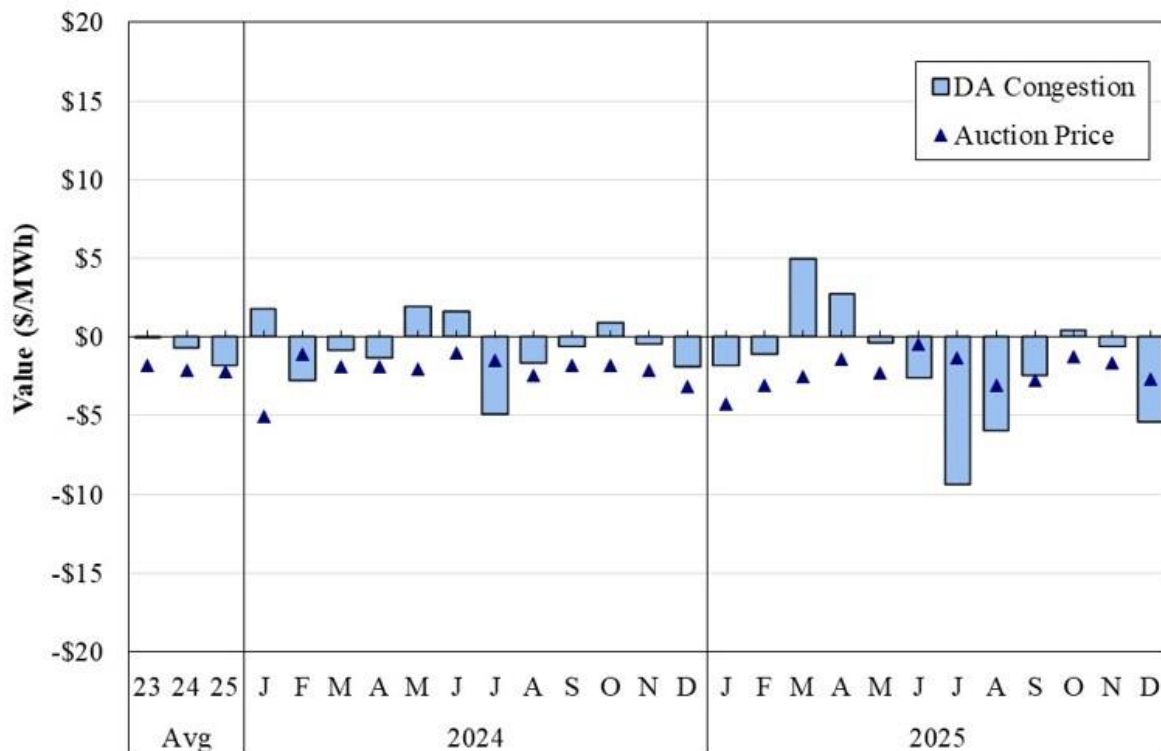
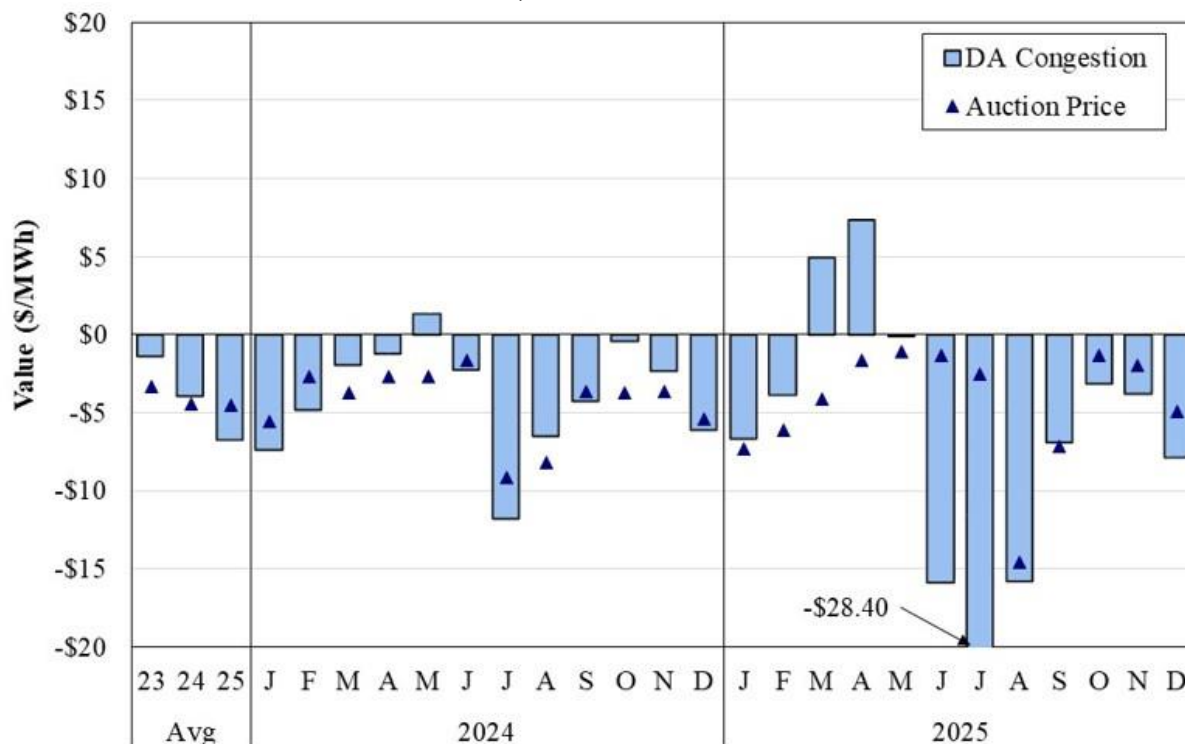


Figure A92: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2024–2025: Peak Hours



D. Multi-Period Monthly FTR Auction Revenues and Obligations

In the MPMA FTR auctions, MISO generally makes additional transmission capability available for sale and sometimes buys back capability on oversold transmission paths. MISO buys back capability by selling “counter-flow” FTRs, which are negatively priced FTRs on oversold paths. In essence, MISO pays a participant to accept an FTR obligation in the opposite direction, offsetting excess FTRs on that transmission path. For example, if MISO issues 250 MW of FTRs over a path that now can accommodate only 200 MW of flow, it can sell 50 MW of counter-flow FTRs so that its net FTR obligation in the day-ahead market is only 200 MW.

MISO cannot do this freely because it is prohibited from clearing the MPMA or monthly FTR auctions with a negative financial residual. Hence, it can sell counter-flow FTRs only to the extent that it sold forward-flow FTRs in the same auction. This limits MISO’s ability to resolve feasibility issues through the MPMA FTR auctions. In other words, when MISO knows a path is oversold, as in the example above, it often cannot reduce FTR obligations on the path by selling counter-flow FTRs. This is not always bad because selling counter-flow FTRs may cost more than simply incurring the FTR shortfall in the day-ahead market.

Figure A93: Prompt-Month MPMA FTR Profitability

Figure A93 evaluates MISO’s sale of forward-flow and counter-flow FTRs by comparing monthly FTR auction revenues with the day-ahead FTR obligations associated with the FTRs sold. The figure separately shows forward-direction and counter-flow FTRs. Net funding costs

equal the difference between auction revenues and day-ahead obligations. A negative value indicates that MISO sold FTRs at a price below their value.

Figure A93: Prompt-Month MPMA FTR Profitability
2024–2025

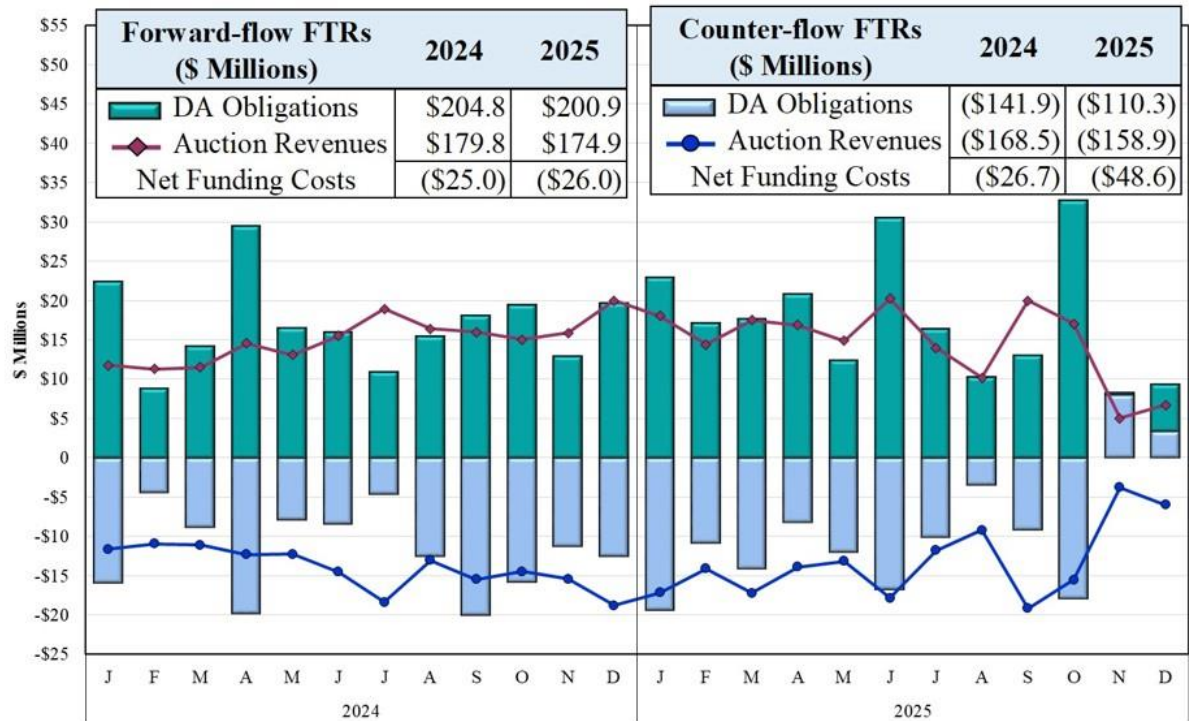


Figure A94: CROW Outage Tickets by Creation Date

Figure A94 depicts how outage reporting aligns with the annual, seasonal, and monthly auctions. The bars classify tickets by the date they were first entered into the CROW system relative to the FTR auction process and by the date the outage began. The left axis shows the number of tickets in the FTR-year for planned transmission line outages of 230kV or more that lasted 5 days or more, categorized by CROW ticket creation date relative to the FTR auctions. The right axis shows the same information as a share of total outage tickets for the year.

This analysis uses the first date the outage was created, regardless of any subsequent revisions to the ticket. It uses the ticket’s actual start date to assign the ticket to the relevant strip outage month. If an outage ticket was first created before the annual auction, it was timely for the annual auction (labeled “Prior to Annual”). Of the remaining tickets, if an outage ticket was first created one month before the first day of the first month of the season, but after the annual auction, it was timely for the MPMA seasonal auction (labeled “Prior to Season”). If an outage ticket was created one month before the start of the relevant outage month, but not before the season, it was timely for the prompt month-monthly auction (labeled “Prior to Month”). Tickets classified as “Month of Outage” were first entered into CROW too late to be included in any of the FTR auctions.

Figure A94: CROW Outage Tickets by Creation Date
2023–2025

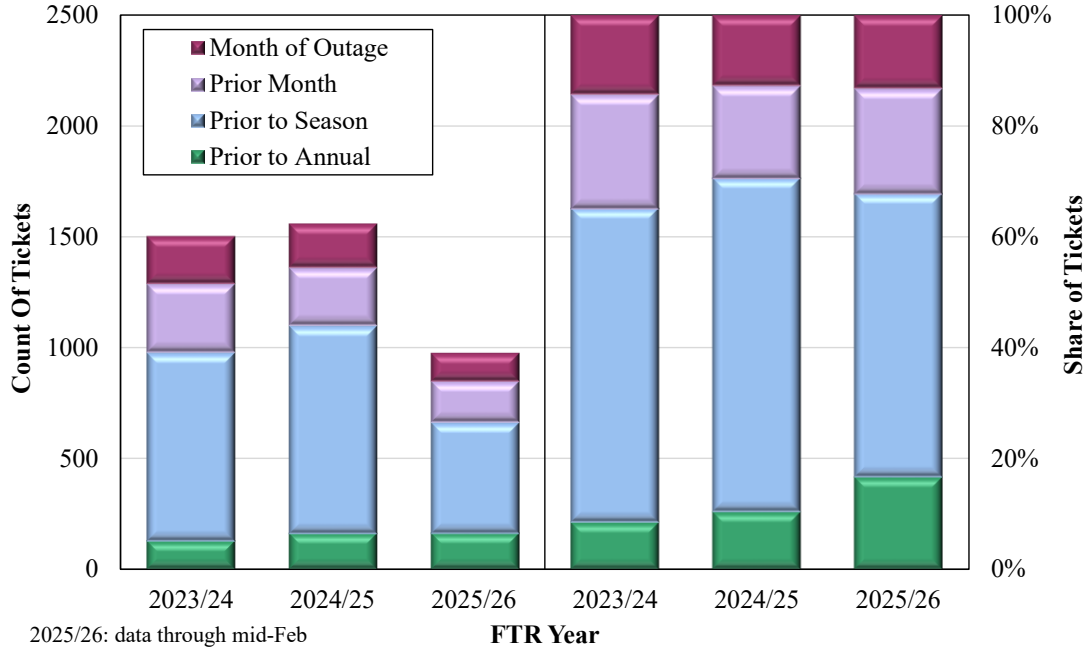
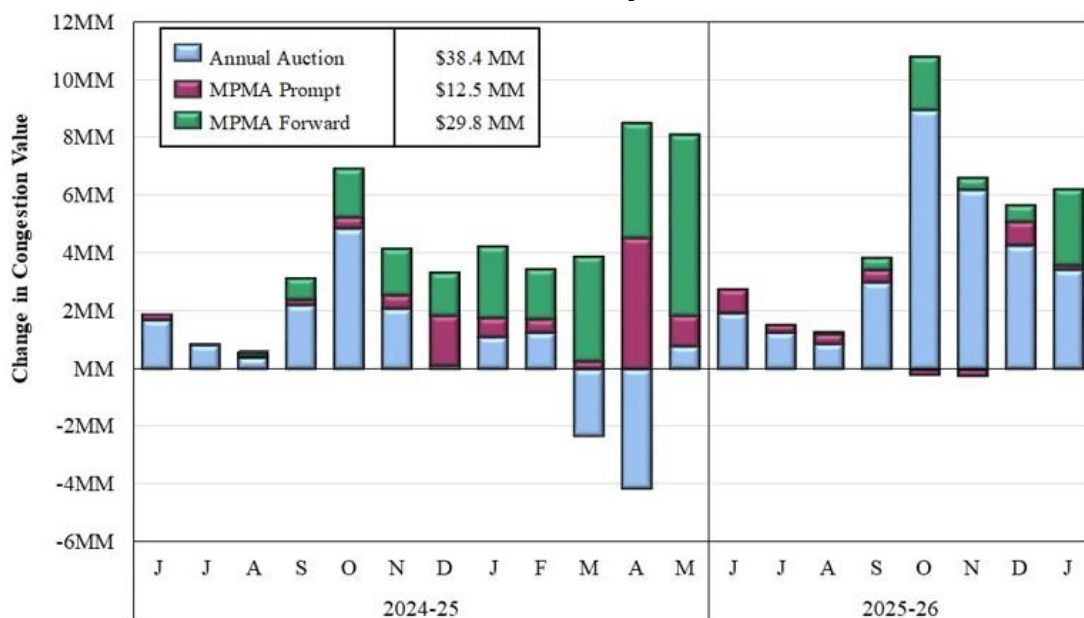


Figure A95: Monthly FTR Valuation Changes for Aggregate Nodes

The redefinition of aggregate nodes is a key issue because it can substantially change the value of FTRs sourcing and sinking at these nodes and cause significant underfunding. Figure A95 shows the monthly change in valuation from redefining aggregate nodes in the current and prior FTR year. The bars are grouped by positions taken in the annual auction (blue), the prompt month of the MPMA (burgundy), and the forward months of the MPMA (green).

Figure A95: Monthly FTR Valuation Changes for Aggregate Nodes
June 2023 – January 2025



E. Market-to-Market Coordination with PJM and SPP

The separate JOAs between MISO and PJM and SPP establish M2M processes to coordinate congestion management for designated transmission constraints on each RTO's system. These processes aim to support reliable congestion management, efficient generation re-dispatch on these constraints, and consistent prices between the markets.

The monitoring RTO (MRTO) is responsible for the security of the flowgate and for monitoring physical flow on it. When an M2M constraint is activated, the MRTO provides its shadow price to the counterparty market along with the requested relief (i.e., the desired reduction in flow). The shadow price measures the MRTO's marginal cost to relieve the constraint. The requested relief varies considerably by constraint and over its coordinated hours. It is based on market conditions and is generally automated, although Reliability Coordinators can select it manually. When the non-monitoring RTO (NMRTTO) receives the shadow price and requested relief quantity, it uses both values in its real-time market to provide as much requested relief as it can at a marginal cost up to the MRTO's shadow price. For settlements, each market is allocated FFE on each M2M constraint. Settlements between the RTOs are based on their flows over the constraint relative to their FFEs.

Figure A96 and Figure A97: PJM and SPP Market-to-Market Events

Figure A96 and Figure A97 show the total M2M constraint-hours coordinated with PJM and SPP, respectively. The top panel shows flowgates coordinated by PJM/SPP, and the bottom panel shows MISO flowgates. The darker-shaded bars show the number of peak hours when M2M flowgates were active, and the lighter shaded bars show the total for off-peak hours.

Figure A96: Market-to-Market Events: MISO and PJM
2024–2025

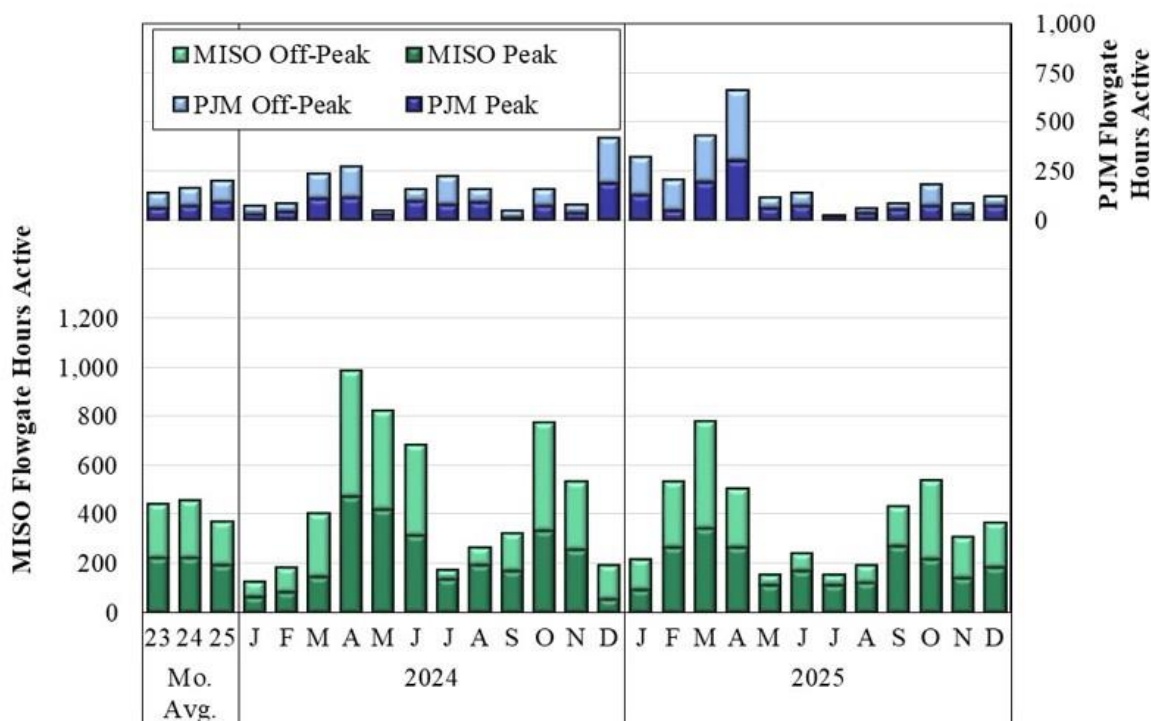


Figure A97: Market-to-Market Events: MISO and SPP
2024–2025

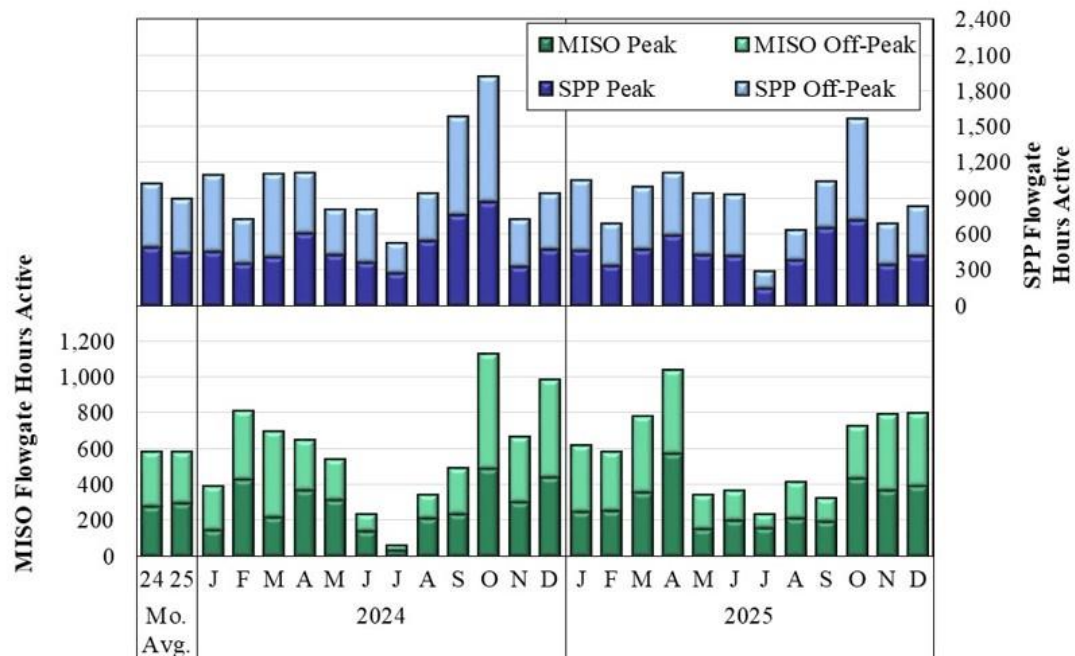
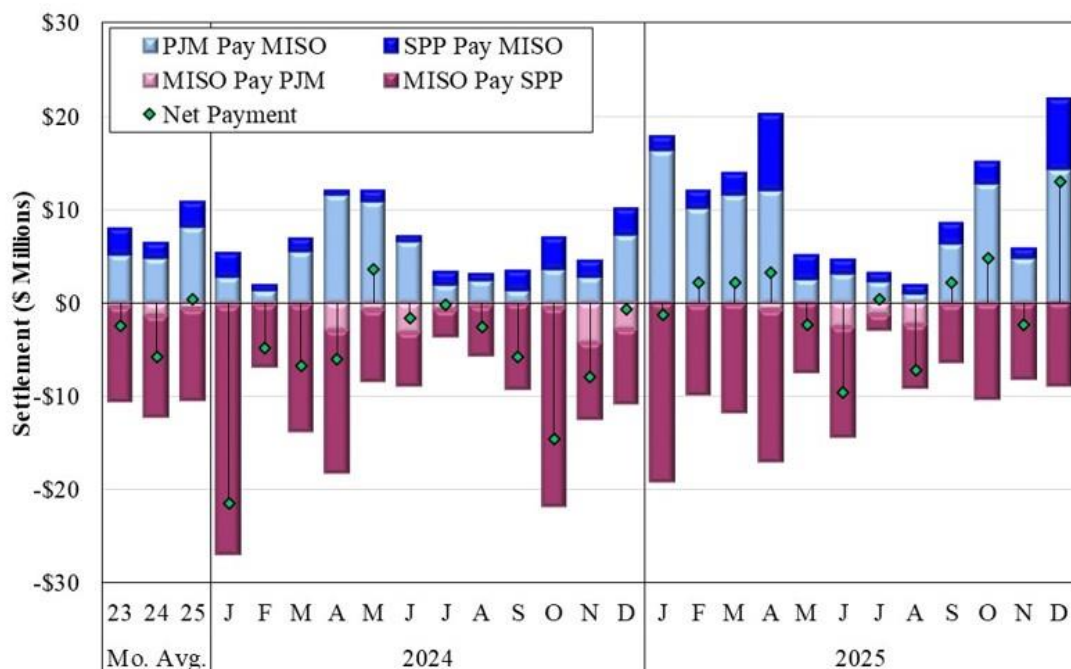


Figure A98: Market-to-Market Settlements

Figure A98 shows MISO's M2M settlements with SPP and PJM. If the NMRTTO's market flow is less than its FFE, the MRTO pays it for the difference at the cost of providing relief. If the NMRTTO's flow exceeds its FFE, it pays the difference times the MRTO's congestion cost.

Figure A98: Market-to-Market Settlements
2024–2025



In the figure, positive values represent payments made to MISO on coordinated flowgates and negative values represent payments from MISO to PJM and SPP on coordinated flowgates. The diamond marker shows net payments to or from MISO in each month.

Table A14: Real-Time Congestion on Constraints Affected by Market-to-Market Issues

M2M coordination allows MISO and neighboring RTOs to coordinate congestion relief on qualifying flowgates. We evaluate the performance of this process by tracking the convergence of the shadow prices of M2M constraints in each market. When coordination is effective, the NMRTTO will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the marginal cost of the MRTTO's relief.

While the M2M process improves efficiency overall, there are three issues that can reduce the efficiency and effectiveness of coordination:

- Failure to test constraints that would likely qualify as M2M constraints;
- Delays in testing constraints after they start binding to determine whether they should be classified as M2M; and
- Delays in activating M2M constraints when they are binding.

These issues can prevent coordination of M2M congestion, causing inefficient dispatch and inappropriately high congestion costs. Serious equity concerns can also arise if the external area exceeds its flow entitlement on the constraint without compensating the MRTTO. Therefore, we identified constraints that were not coordinated because of these issues. The screens identified non-M2M constraints that should have been coordinated as M2M with either PJM or SPP in 2025. We then quantified congestion on these constraints, as shown in Table A14.

Our screening accounts for the time required to identify, test, and activate a M2M:

- *Never Classified as M2M.* MISO did not request testing for most of these constraints. To exclude transitory constraints that would not warrant testing, we exclude constraints that bound on only one day during the year.
- *Delay in Testing.* We removed the first two days a constraint bound in real time to account for the time needed to perform the tests.
- *Delay in Activation.* We did not remove any days for constraints previously identified as M2M.

**Table A14: Real-Time Congestion on Constraints Affected by Market-to-Market Issues
2023–2025**

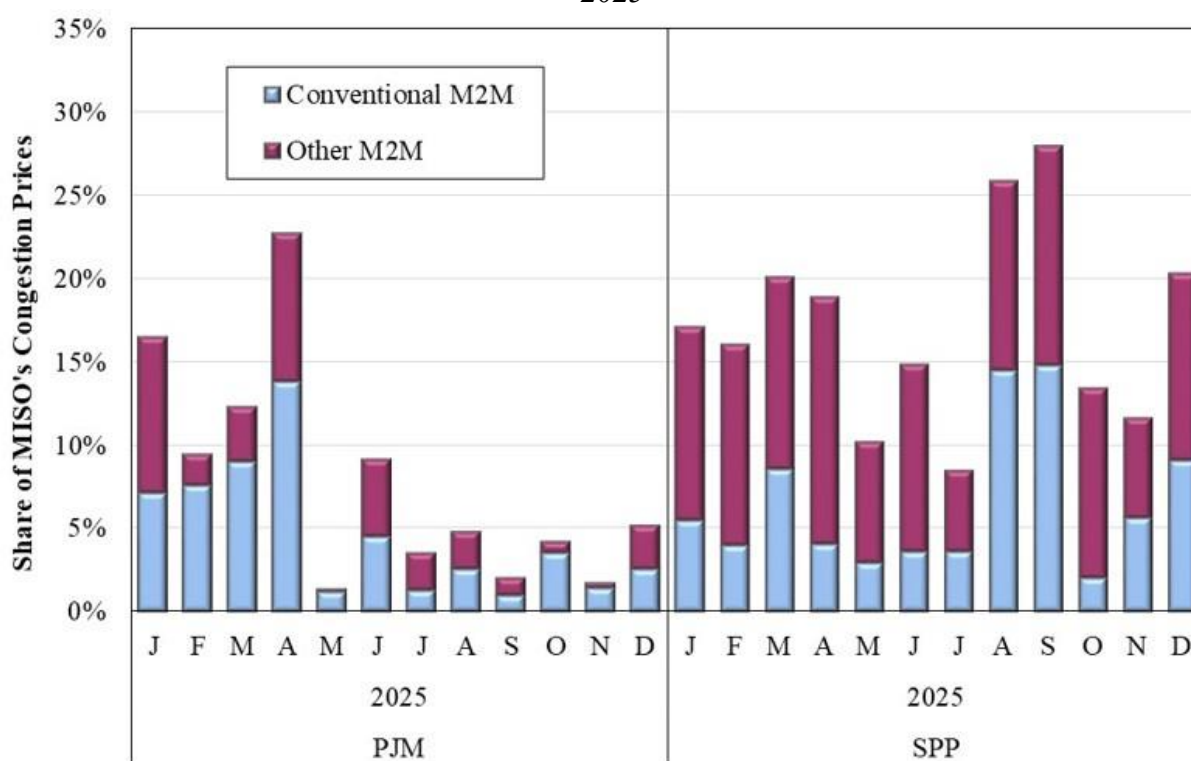
Item Description	PJM (\$ Millions)			SPP (\$ Millions)			Total (\$ Millions)		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Never classified as M2M	\$5	\$38	\$25	\$33	\$4	\$4	\$38	\$42	\$29
M2M Testing Delay	\$5	\$2	\$9	\$40	\$22	\$34	\$45	\$24	\$43
M2M Activation Delay	\$0	\$2	\$1	\$1	\$1	\$24	\$2	\$3	\$25
Total	\$10	\$42	\$35	\$74	\$27	\$62	\$84	\$69	\$97

Figure A99: Congestion Costs on PJM and SPP Flowgates

Because MISO market flows comprise a small share of their physical capability, external M2M constraints account for a small share of congestion value in MISO's market. However, these external constraints significantly affect locational pricing and market revenues for MISO generators. Figure A99 shows the contribution of SPP and PJM transmission constraints to congestion pricing in MISO markets. It shows the total share of locational congestion prices in MISO's LMPs that PJM and SPP constraints coordinated through the M2M process cause.

The figure subdivides the price effects into conventional and non-conventional M2M procedures (i.e., using overrides, safe operating modes, TLRs, or other processes to manage congestion). Although often justified, these non-conventional procedures are less efficient and lead to higher congestion costs. Therefore, understanding the extent of their use is valuable.

Figure A99: Congestion Costs on PJM and SPP Flowgates
2025



Market-to-Market Test Criteria Software

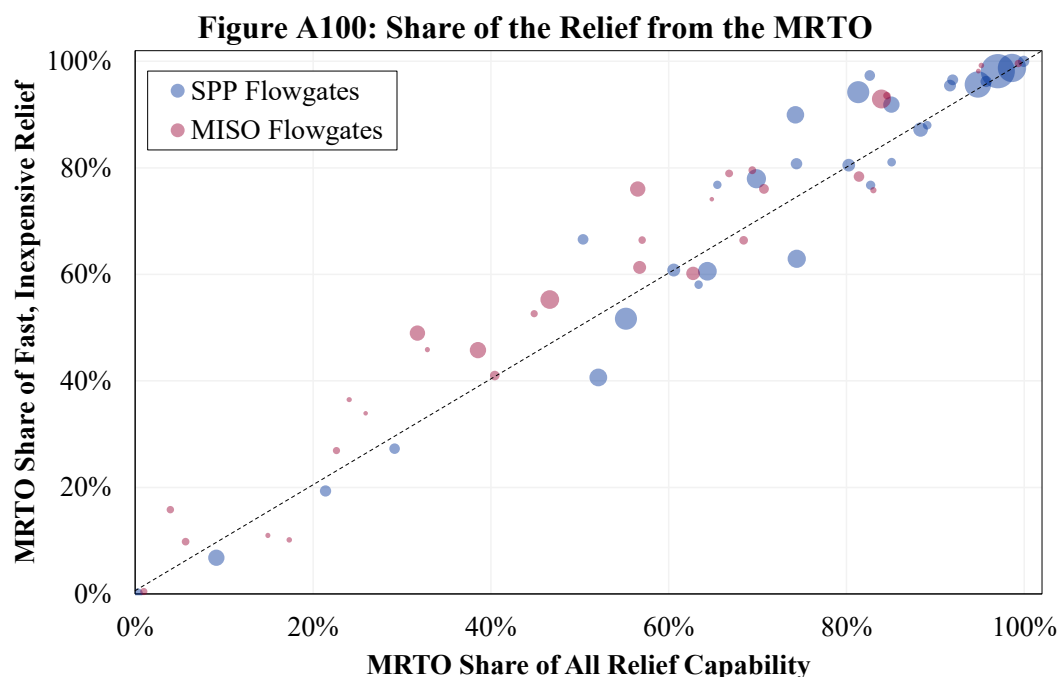
Identifying the constraints to coordinate helps ensure efficient, reliable coordination, establish equitable settlements, and improve price signals in the NMRTO market. Currently, a constraint is identified as a M2M constraint when the NMRTO has:

- a generator with a shift factor greater than five percent; or
- Market flows over the MRTO's constraint greater than 25 percent of total flows (SPP JOA) or 35 percent of total flows (PJM JOA).

These two tests do not identify constraints that would benefit from coordination well because they do not consider the economic relief the NMRTTO will likely have available. The single-generator test is particularly questionable because it ignores the unit's size and economics, so it does not ensure that the NMRTTO has any economic relief.

Figure A100: Share of the Relief from the MRTTO

Figure A100 evaluates the effectiveness of the coordination process by showing the share of economic relief from SPP and MISO for their respective M2M constraints that bound from June 2018 through May 2019. The x-axis shows the portion of the total relief held by the MRTTO, and the y-axis shows the available economic relief held by the MRTTO. Bubble size indicates the amount of congestion associated with each constraint, and color identifies MISO and SPP constraints. Under perfect convergence, the data points would lie on the dashed 45-degree line. Even if observations fall on this line, convergence may still be poor during some events or periods. When both percentages are high, coordinating the constraint provides limited value because the NMRTTO has a small share of the relief capability.



Evaluation of Relief Request Software

The MRTTO coordinates management of the constraint with the NMRTTO by sending its marginal cost of providing relief on the constraint (i.e., the “shadow price”) and the quantity of relief it wants the NMRTTO to provide (at a cost not to exceed the shadow price). Therefore, successful M2M coordination depends in part on optimizing the amount of relief the MRTTO requests. If the request is too low, the NMRTTO will not provide all available economic relief, resulting in higher congestion costs and potentially higher settlement costs for the NMRTTO. If the request is too high, it can cause congestion oscillation and raise costs. This section describes and evaluates the effectiveness of the relief request software.

Table A15: Shadow Price Convergence on M2M Flowgates with SPP in 2025

MISO and its partners can agree to transfer monitoring responsibilities of a flowgate to the NMRTTO, i.e., “reverse role” flowgate configuration. The NMRTTO accepts control and acts as the MRTTO, modeling the physical limit of the flowgate in its market dispatch. The reverse role configuration can improve efficiency and reliability when the NMRTTO has more effective relief. MISO has accepted monitoring responsibilities for many SPP flowgates.

The quantity of relief requested by the MRTTO is based on the difference between physical flow and the transmission facility’s limit. The M2M software contains two parameters (“P1” and “P2,” more commonly known as “Adders”), which increase the relief request quantity by a given percentage. These Adders are applied when the constraint is binding but not violated in the MRTTO dispatch model. Without them, the relief request would not rise even if the MRTTO shadow price is much higher than the NMRTTO’s, which is inefficient. MISO sets both Adders to five percent by default, but Operations can override this value on a per-flowgate basis. Over the past two years, SPP has requested that MISO set both adders to zero on all Reverse Role flowgates, and MISO has complied. As a result, SPP-owned flowgates controlled by MISO have exhibited persistent shadow price separation.

We evaluated M2M shadow price convergence with SPP for reverse role and standard flowgates. Table A15 shows the convergence the markets’ real-time shadow prices for every flowgate under MISO control and the cost of non-convergence on those flowgates. If a flowgate was transferred during 2025, we considered each configuration as a separate flowgate.

We calculate the cost of non-convergence for each 5-minute interval as one-twelfth the product of MISO’s shadow price (in dollars per MWh) times MISO’s state-estimated flow. The MISO and SPP shadow prices shown are averages of all 5-minute intervals when the flowgate was binding in either partner’s real-time market dispatch software. The final shadow price ratio for each group (standard and reverse-role) is the average real-time shadow price for each flowgate weighted by congestion value, which controls for both the frequency and severity of binding.

Table A15: Shadow Price Convergence on M2M Flowgates with SPP in 2025

Type	# Flowgates	Avg. % Convergence with MISO Shadow Price	Cost of Non-Convergence (\$ Millions)
Standard	90	92%	\$36
Reverse-Role	46	151%	\$85

Figure A101: Share of Economic Relief on SPP-Owned Flowgates

We also evaluated the share of economic generation relief available in each partner’s market to assess appropriate use of the Reverse Role configuration. We calculate economic generation relief by comparing estimated cost data for each generator with MISO LMPs in every interval when the constraint was binding in either MISO or SPP. We then calculate each partner’s share of total economic relief, excluding small quantities from other regions. In Figure A101, we show each partner’s share of economic generation relief for all SPP-owned flowgates in 2025.

The left panel shows SPP flowgates that MISO controls under Reverse Role configuration, and the right panel shows SPP flowgates that SPP controls. Each stacked bar represents one flowgate. The red bars show SPP's percentage share of total economic relief, and the blue bars show MISO's percentage share.

Figure A101: Share of Economic Relief on SPP-Owned Flowgates in 2025

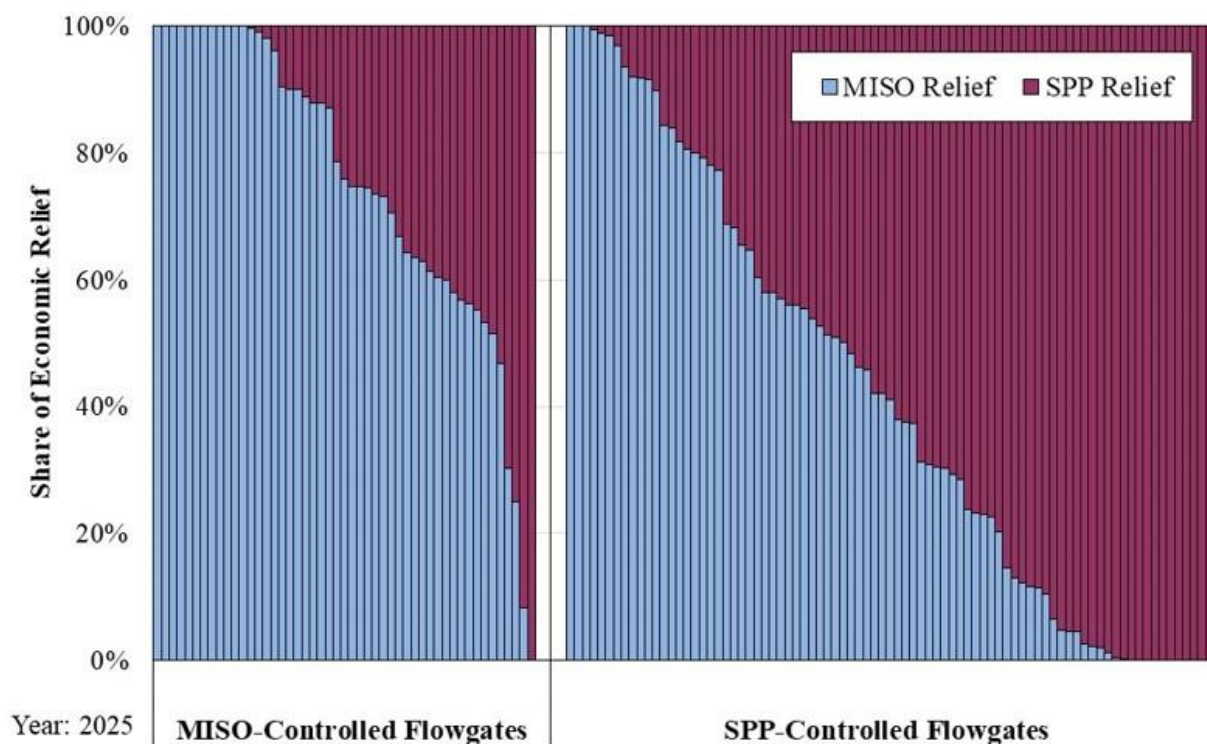


Figure A102 and Figure A103: Shadow Price Convergence MISO-SPP and MISO-PJM

Figure A102 and Figure A103 evaluate the effectiveness of the coordination process by showing average shadow price convergence on individual constraints during the hours when they are activated. The figures show the MRTTO's average shadow price on the x-axis and the NMRTTO's average shadow price on the y-axis. The bubble size indicates the amount of congestion associated with each constraint, and the colors identify MISO and SPP or PJM constraints. Under perfect convergence, the data points would lie on the dashed 45-degree line. The figures label the constraints with the highest congestion during the last year for each RTO.

Figure A102: Shadow Price Convergence MISO-SPP in 2025

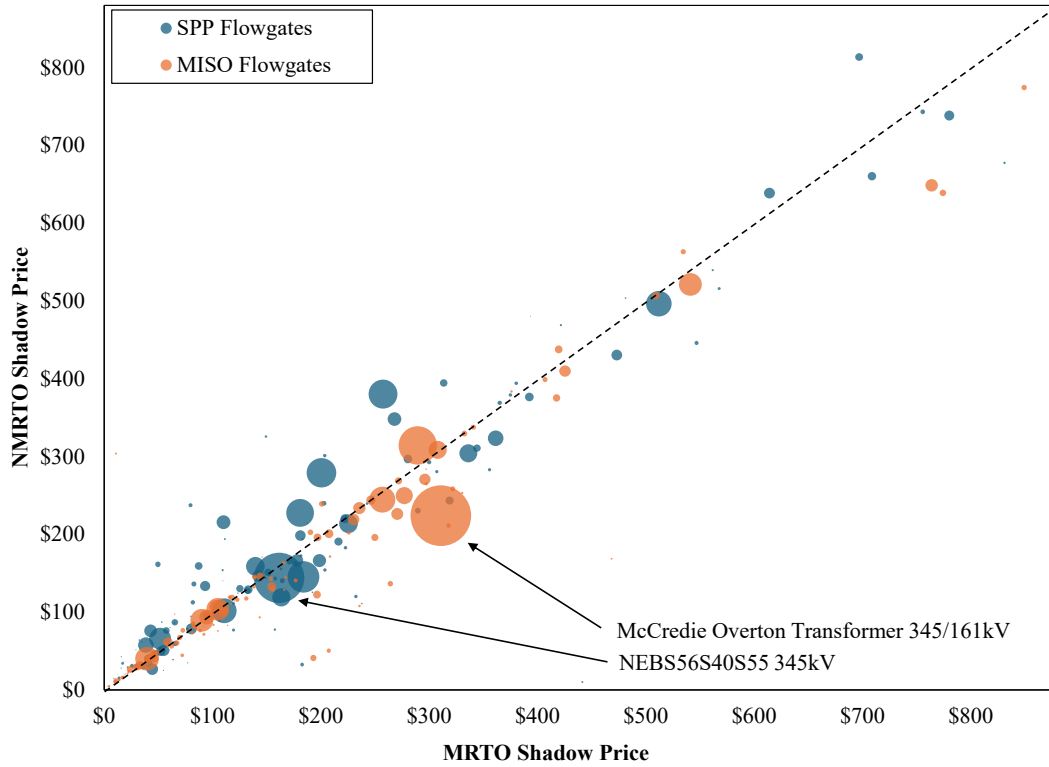


Figure A103: Shadow Price Convergence MISO-PJM in 2025

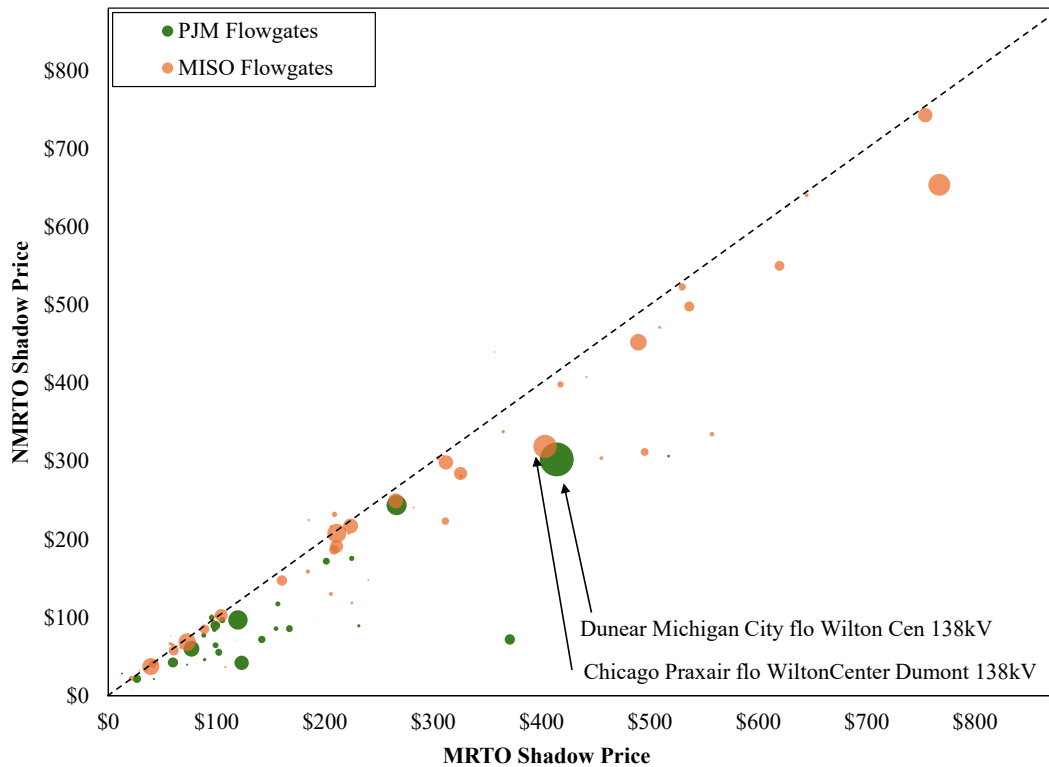


Figure A104 and Figure A105: Shadow Price Convergence MISO-SPP and MISO-PJM

Figure A104 and Figure A105 evaluate the effectiveness of the coordination process by showing average shadow price convergence on individual constraints during the hours when the constraints are activated. The green bar shows the portion of the JOA settlement attributable to shadow price differences on excess market flows as the NMRTTO. Because congestion revenues fall short, these JOA payments must be uplifted through Revenue Neutrality Uplift (RNU). The blue bar represents the opposite case: the MRTTO collects net congestion revenue when the NMRTTO is under its FFE and provides relief at a lower shadow price. In this case, the MRTTO pays for congestion relief at a lower cost than it charges market participants loading the constraint.

Figure A104: JOA Uplift Impact of Shadow Price Non-Convergence MISO-SPP
2020–2025

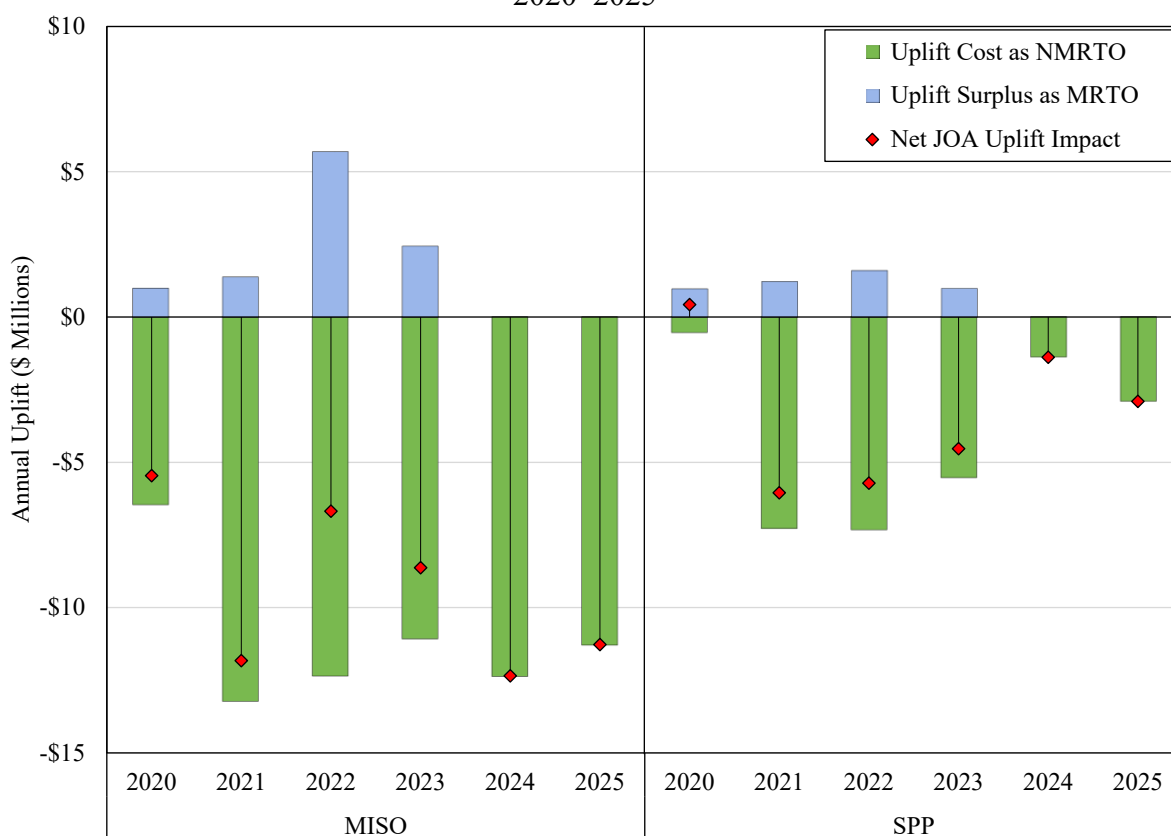
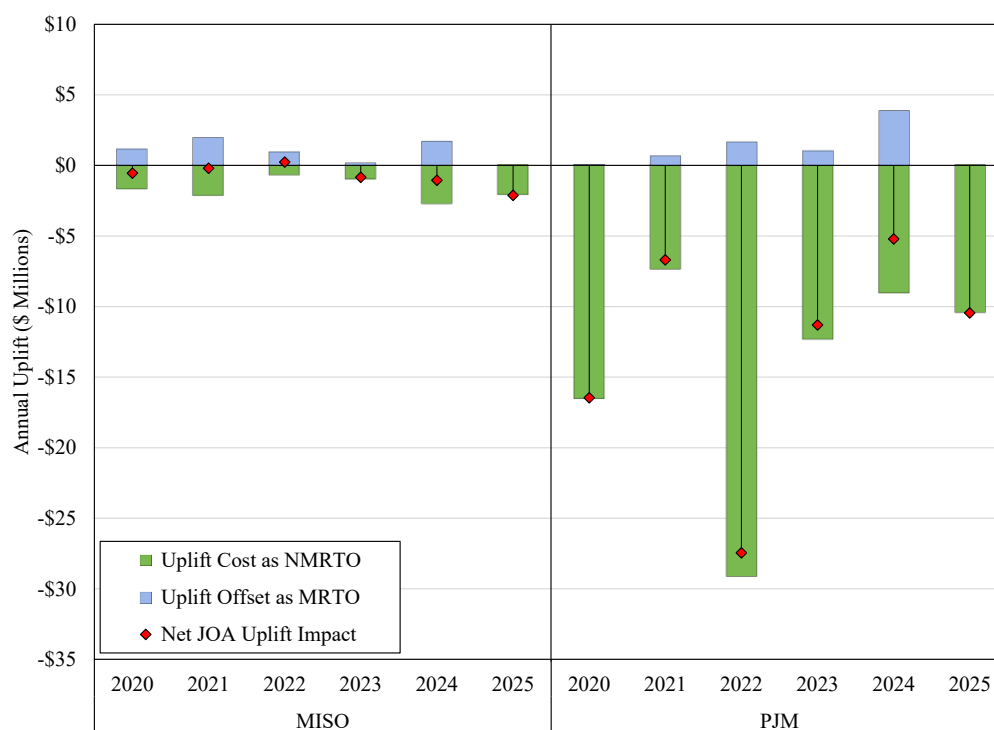


Figure A105: JOA Uplift Impact of Shadow Price Non-Convergence MISO-PJM 2020–2025***Day-Ahead Modeling of M2M Constraints***

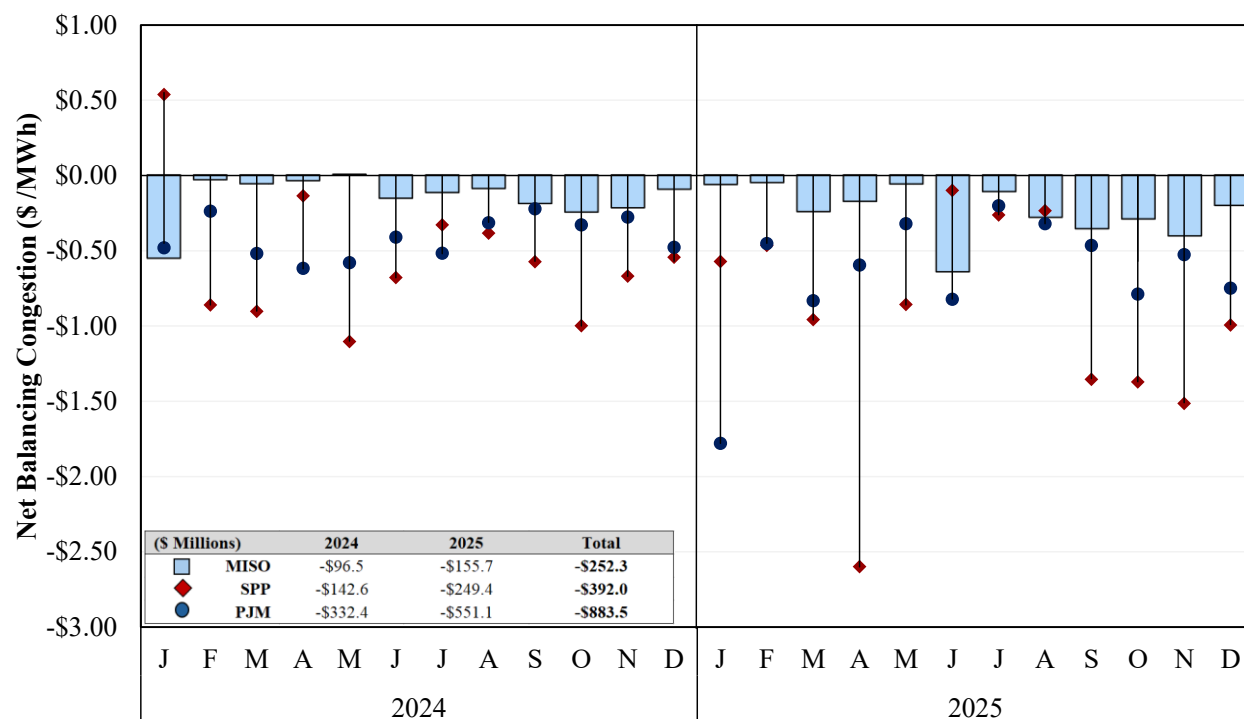
RTOs' day-ahead modelling of their neighbor's M2M constraints can also lead to suboptimal coordination or increased costs under the M2M processes.

The JOA between MISO and SPP or MISO and PJM requires each RTO to model the other's M2M constraints in its day-ahead market. This is valuable because the day-ahead market coordinates the generation that will be committed and dispatched and establishes financially binding schedules (generation injections, load withdrawals, and resulting network flows). When a constraint is not modeled, market participants can purchase flows over the constraint that far exceed its limit. This can result in sizable real-time costs to buy back the excess flows.

Figure A106: Monthly Balancing Congestion Revenue

Balancing congestion occurs when day-ahead flows scheduled over a constraint exceed the flows that the real-time market can accommodate. This can occur when the constraint limit falls because of an outage or another factor, or when the day-ahead market does not fully model the constraint. Although we do not have the data needed to quantify these amounts for MISO constraints, Figure A106 shows net balancing congestion per MWh in MISO, SPP, and PJM over the past two years. Data for MISO and SPP comes from the respective Revenue Neutrality Report (RNU), while data for PJM comes from the Balancing Transmission Congestion Credit Rate (\$/MWh) times load.

Figure A106: Monthly Balancing Congestion Revenue
2024–2025



F. Congestion on Other External Constraints

This subsection analyzes congestion on external constraints in adjacent systems that the M2M processes do not coordinate. MISO incurs congestion on external constraints when a neighboring system calls a TLR for a constraint. When this occurs, MISO activates the constraint as it would an internal constraint and seeks to reduce its flow over the constraint by the required relief amount. To provide the requested relief, MISO calculates its market flows before the TLR call and sets a limit equal to those market flows less the requested relief. This process is efficient only if the cost of providing relief is lower than the other system's cost to manage flow on the constraint. Historically, this has not been true. One concern is that relief obligations are based on forward flows, not MISO's net flows, which may be lower because of counterflow on the constraint. Because the relief obligation may be outsized, providing relief is often very costly, and MISO includes its marginal cost of providing the relief in its LMPs.

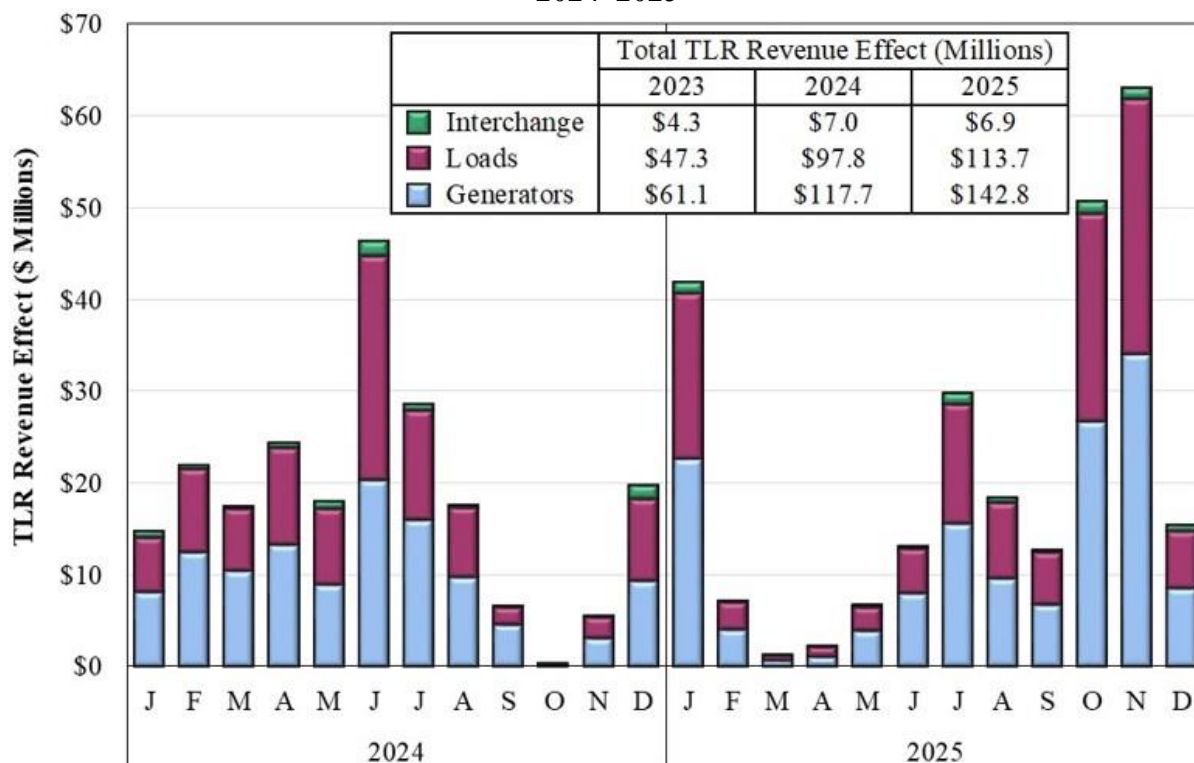
Figure A107: Real-Time Valuation Effect of TLR Constraints

Because external constraints can substantially change LMPs in MISO, we estimate these effects by calculating the increase in real-time payments by loads and the reduction in payments to generators that the external constraints cause.²³ Figure A107 shows the increases and decreases in hourly revenues that result from binding TLR constraints. The reported congestion value for these constraints is low because MISO's market flow on external flowgates is generally low or

²³ External constraints also affect interface prices settlements, an issue that is further evaluated in Section VII.C.

negative. Therefore, it masks the larger effect these constraints have on MISO's dispatch and pricing.

Figure A107: Real-Time Valuation Effect of TLR Constraints
2024–2025



With the exception of M2M coordination between MISO and PJM, MISO and SPP, and NYISO and PJM, Reliability Coordinators in the Eastern Interconnect continue to rely on TLR procedures and the North American Electric Reliability (NERC) Interchange Distribution Calculator (IDC)²⁴ to manage congestion caused in part by schedules and the dispatch activity of external entities.

Before energy markets were introduced in 2005, the TLR process managed nearly all congestion on MISO transmission facilities. TLR is an Eastern Interconnection-wide process that allows Reliability Coordinators to obtain relief from external entities with scheduled transactions that load the constraint. When an external, non-M2M constraint is binding and a TLR is called, the IDC assigns MISO a relief obligation. MISO responds by activating the external constraint so that the real-time dispatch model redispatches its resources to reduce MISO's market flows over the constrained transmission facility by the requested amount.

External entities not dispatched by MISO also contribute to flows on MISO flowgates. If external transactions contribute more than five percent of the total flow on a MISO binding

²⁴ To implement TLR procedures on defined flowgates, Reliability Coordinators depend upon the IDC. The IDC provides Reliability Coordinators with the amount of relief available from curtailment of physical transactions. In addition, MISO, PJM, and SPP provide their market flow impacts to the IDC for Reliability Coordinators to use in the TLR process.

facility, MISO can invoke a TLR to curtail those transactions and reduce flow over the constrained facility.

Compared to economic generation dispatch through LMP markets, the TLR process is an inefficient, rudimentary means of managing congestion. TLR provides less timely, less certain control of power flows over the system. Prior studies found that the TLR process resulted in approximately three times more curtailments, on average, than economic redispatch would require.

Table A16: Economic Relief from TVA and AECI Generators on MISO Constraints

Table A16 illustrates the potential savings that could be achieved by utilizing TVA and AECI generation to provide lower cost relief on constraints binding in MISO. Our analysis focuses on economic relief on MISO’s internal constraints and quantifies the potential value of a joint operating agreement to coordinate economic congestion management with TVA. The left column indicates the value of real-time congestion when economic relief is available from TVA and AECI, while the right column shows the potential savings from economic coordination.

Table A16: Economic Relief from TVA and AECI Generators on MISO Constraints

Year: 2025	Total Congestion Value (\$ Millions)	Re-dispatch Savings (\$ Millions)
TVA Generators	\$238.9 M	\$8.0 M
AECI Generators	\$293.6 M	\$25.0 M
Total*	\$381.8 M	\$32.5 M

* Total represents the total impact of TVA generators that includes AECI generators, avoiding any double counting.

G. Congestion Manageability

MISO uses its real-time market model to maintain flow on each activated constraint at or below the operating limit while minimizing total production cost. As flow over a constraint approaches its limit, MISO activates the constraint in the market model. This causes MISO’s energy market to alter the dispatch of generators that affects the transmission constraint as determined by their GSFs.²⁵

While this is intended to reduce the flow on the constraint, some constraints can be difficult to manage if the available relief from generating resources is limited. The available relief is reduced when the most effective generators: (a) are not online; or (b) have inflexible operating parameters (lower than actual physical capabilities).

When available relief capability is insufficient to control the flow over the transmission line in the next five-minute interval, we refer to the constraint as “unmanageable”. The presence of an

²⁵ GSFs are the share of a generator’s output that will flow over a constraint. A negative shift factor means it is providing relief (or “counter-flow”) and a positive shift factor means flow is in the direction of the constraint.

unmanageable constraint does not mean the system is unreliable because MISO’s performance criteria allow up to 20 minutes to restore control on most constraints. If control is not restored within 30 minutes, a reporting criterion is triggered. MISO operates constraints most critical to system reliability (e.g., those that could lead to cascading outages) more conservatively.

Figure A108: Constraint Manageability

Figure A108 shows the monthly frequency of manageable and unmanageable binding constraints from 2024 to 2025.

Figure A108: Constraint Manageability
2024–2025

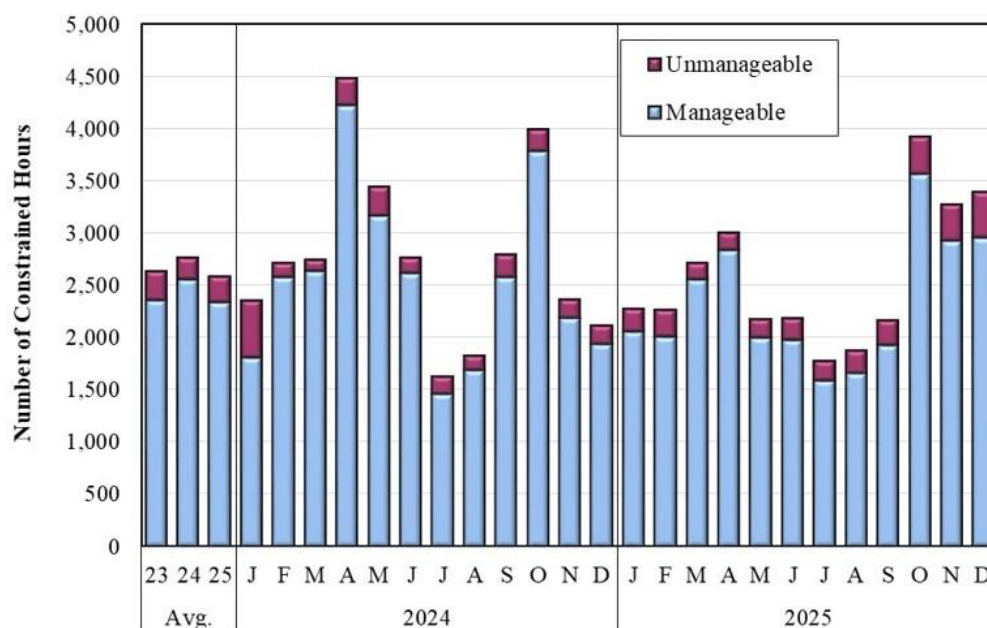


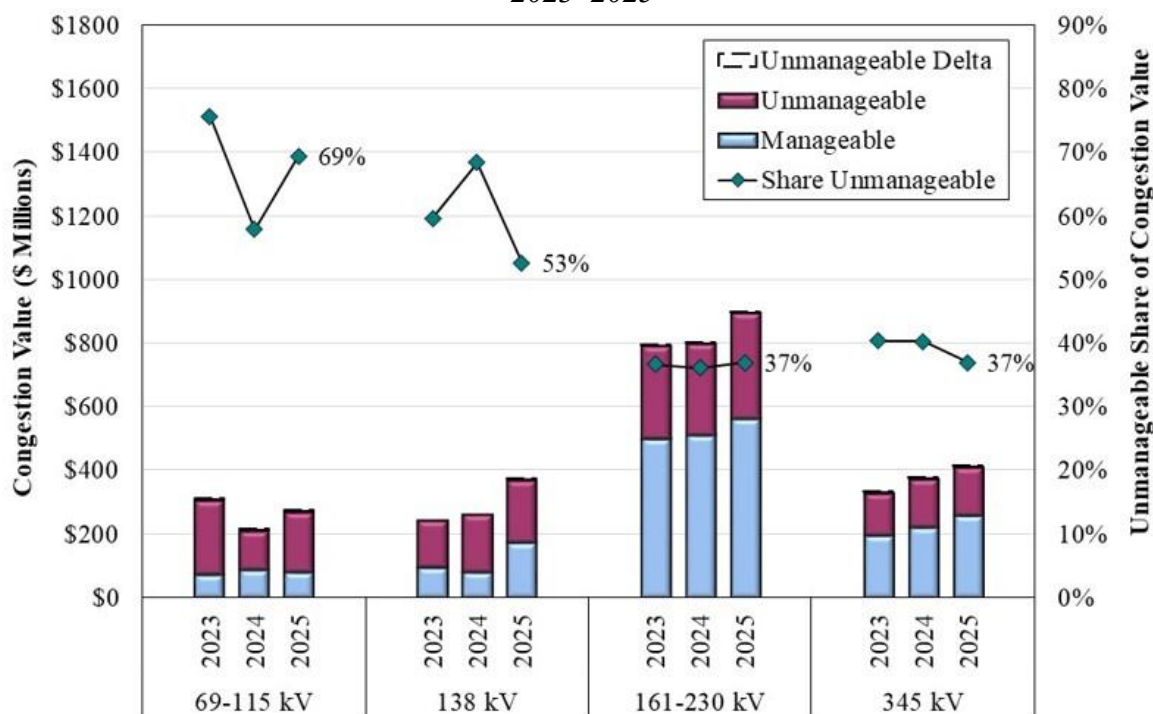
Figure A109: Real-Time Congestion Value by Voltage Level

Because constraints are frequently unmanageable, unmanageable congestion must be priced efficiently and reflected in MISO’s LMPs. The real-time market model uses Transmission Constraint Demand Curves (TCDCs) to cap the marginal cost (shadow price) the energy market incurs to reduce constraint flows to their limits. These TCDCs set the shadow price and, thus, the congestion component of the LMPs at all locations affected by the violated constraints. Therefore, efficient market performance requires the TCDC to reflect the reliability cost of violating the constraint.

Figure A109 examines constraint manageability by voltage level. Because of the physical properties of electricity, more power flows over higher-voltage facilities. As a result, resources and loads over a wide geographic area affect higher-voltage constraints. Conversely, operators typically must manage low-voltage constraints with a smaller set of resources. Figure A109 separately shows results for constraints that are not in violation (i.e., “manageable”), those that are in violation (i.e., “unmanageable”), and the congestion not priced when constraints are in

violation. Unpriced congestion is the difference between the full reliability value of the constraint (i.e., the TCDC) and the relaxed shadow price used to calculate prices.²⁶

Figure A109: Real-Time Congestion Value by Voltage Level
2023–2025



H. Transmission Ratings and Constraint Limits

For most transmission constraints, the amount of power that can flow through a facility is related to the heat caused by the power flow. When ambient temperatures are cooler than the typical assumptions used to rate facilities, the facilities can accommodate additional power flows.²⁷ Therefore, Ambient Adjusted Ratings (AARs) for temperature would allow MISO to operate at higher transmission limits and achieve substantial production cost savings if transmission owners develop and submit them. Most transmission owners do not currently provide AARs.

For contingency constraints, ratings should correspond to the short-term emergency rating level (i.e., the flow level that the monitored facility can reliably accommodate in the short term if the contingency occurs). Most transmission owners provide MISO with both normal and emergency limits, as required under the Transmission Owner’s Agreement.²⁸ However, some transmission owners provide only normal ratings for most facilities.

²⁶ This figure excludes some less common voltages, such as 120 and 500 kV, and about six percent of total congestion value due to constraints that could not be classified according to voltage class.

²⁷ In some areas where wind speed is a more important ambient factor than temperature, permissible ratings could be significantly impacted by the wind speed. We have not estimated benefits of improved ratings due to wind speed measurements or other factors that if measured could allow for a dynamic increase in ratings.

²⁸ The Transmission Owners Agreement calls for transmission owners to submit normal transmission ratings on base (non-contingency) constraints and emergency ratings on contingency constraints (“temporary” flow levels that can be reliably accommodated for two to four hours). Most constraints are contingency constraints.

Estimated Benefits of Using AARs and Emergency Ratings

This subsection examines the value of more fully utilizing the existing transmission network through temperature-adjusted emergency ratings for MISO's transmission facilities.

Figure A110: Potential Value of Additional Transmission Capability

To estimate the congestion savings of using temperature-adjusted ratings, we performed a study using NERC/IEEE estimates of ambient temperature effects on transmission ratings. Using the formulae and data from IEEE Standards (IEEE Std C37.30.1™-2011), we derived ratios of allowable continuous facility current (flow) at prevailing ambient temperatures to the Rated Continuous Current for different classes of transmission elements (e.g., Forced Air-Cooled Transformers and Transmission Lines). We used the most conservative class of permissible ratings increases under the Standard for the type of element (Line or Transformer). We then used prevailing ambient temperatures in the area to estimate the AAR. We estimated the value of raising transmission limits by multiplying the limit change by the real-time shadow price.

To estimate the benefits of emergency ratings, we identified transmission elements with identical normal and emergency ratings. For these elements, we assumed that the short-term emergency rating would increase by 10 percent. This is a reasonable assumption because average emergency ratings provided by transmission owners are 9 to 17 percent higher for each facility type and voltage class combination. Figure A110 shows the estimated benefits of using temperature-adjusted emergency ratings by month and region for the last two years.

Figure A110: Potential Value of Additional Transmission Capability
2024–2025

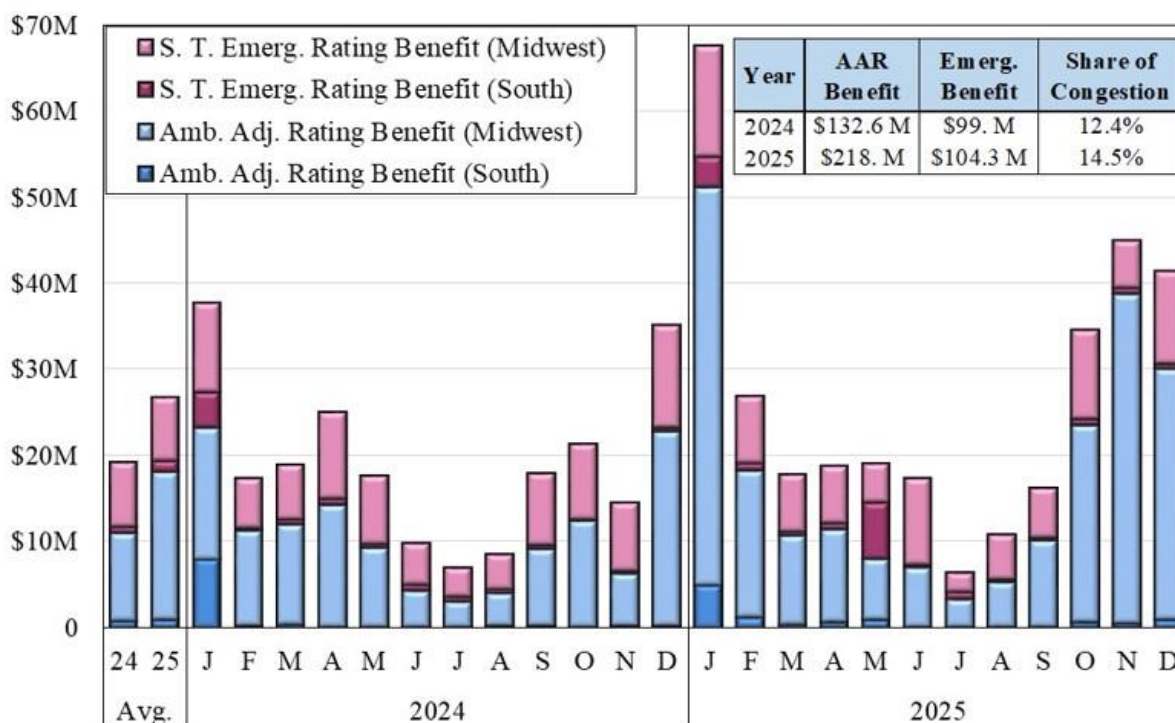


Figure A111: Estimated Actual Savings of AARs

We estimated the savings currently achieved by two transmission owners that temperature-adjust a substantial number of their transmission facilities. Neither transmission owner adjusts its ratings hourly to maximize these benefits, but the benefits remain substantial. Figure A111 summarizes our estimates of the congestion savings by region actually realized from these two transmission owners’ uses of temperature-adjusted ratings. We calculate the congestion savings as the product of the prevailing shadow price and the difference between the constraint limit, including the temperature adjustment, and the seasonal emergency rating. This methodology provides a conservative estimate of savings because the shadow price would increase if the market controlled to a lower, non-adjusted rating.

Figure A111: Estimated Actual Savings of AARs
2024–2025

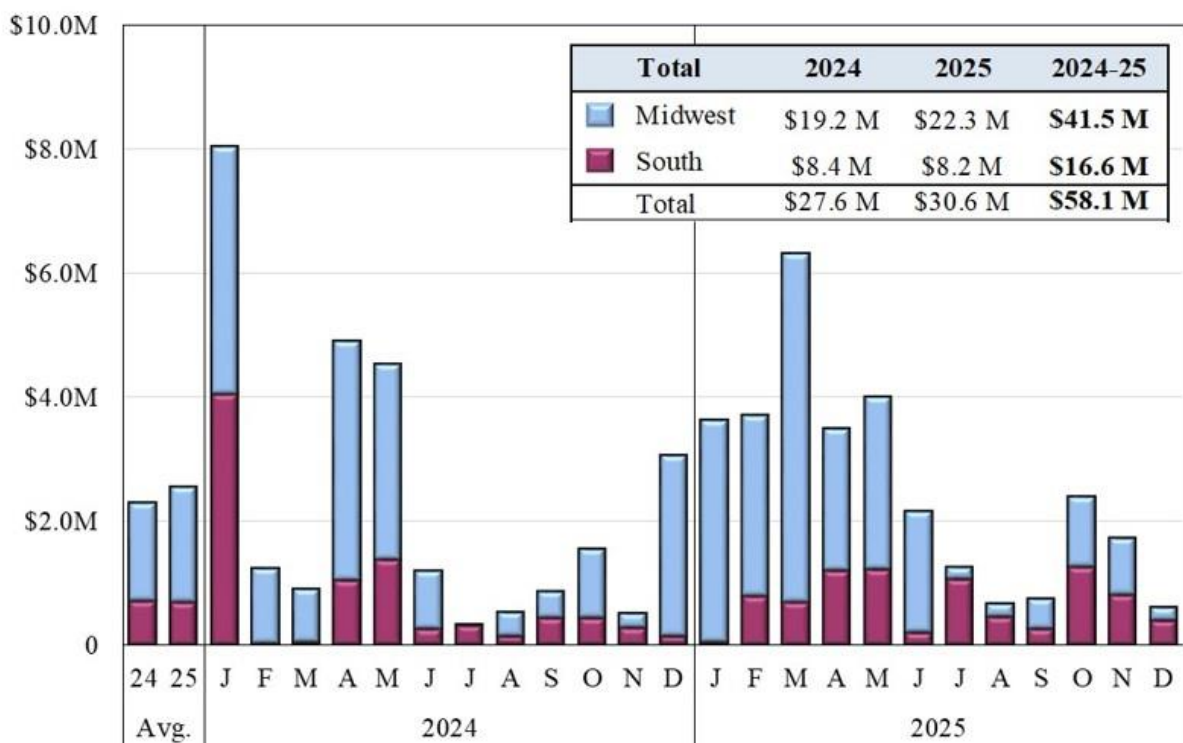
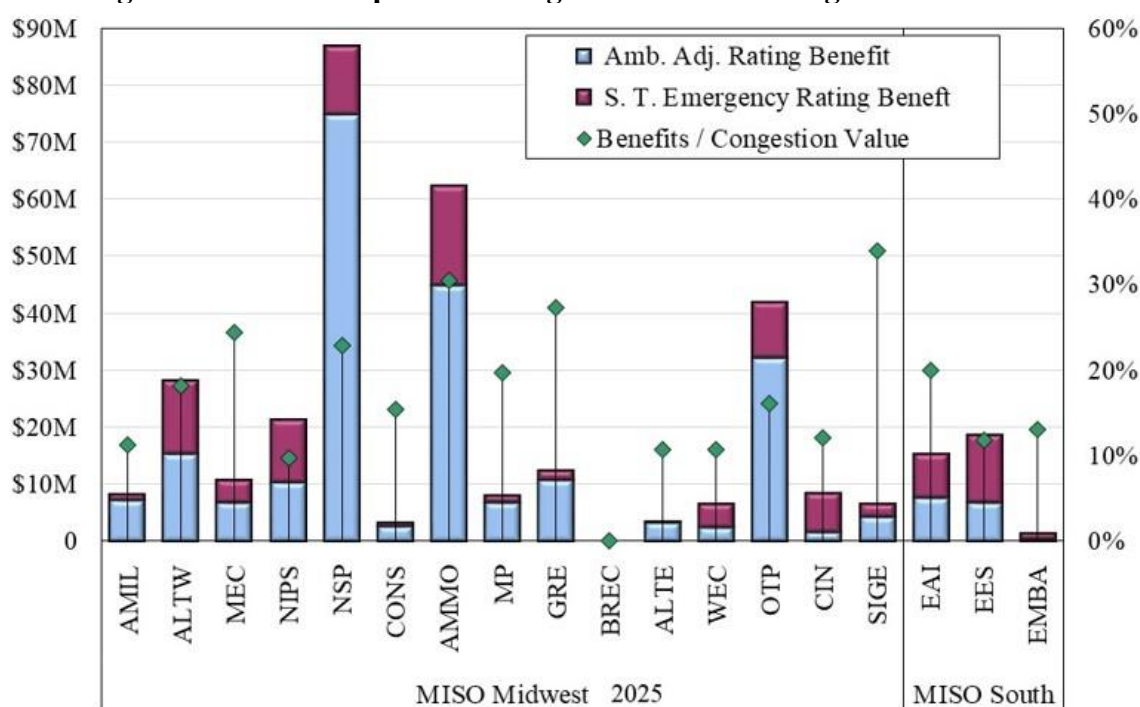


Figure A112: Area-Specific Savings Potential of Ratings Enhancement

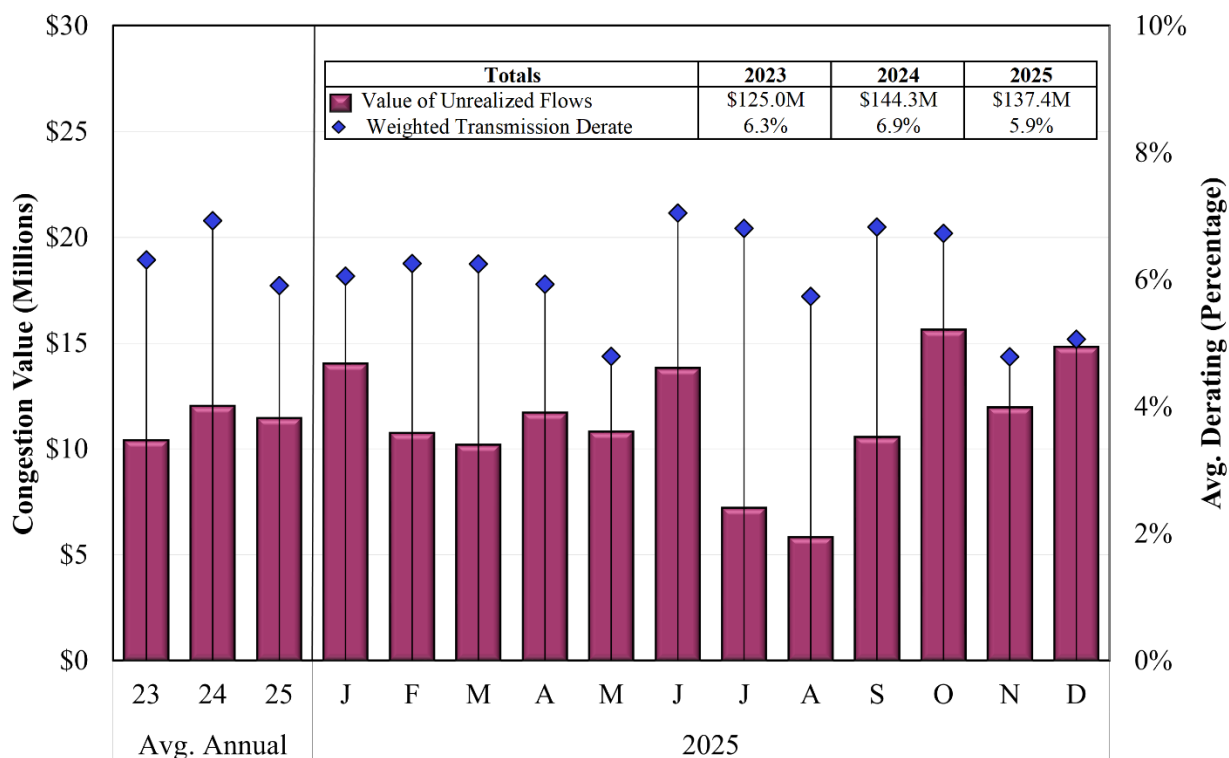
Figure A112 organizes the potential savings in MISO’s 24 most congested areas. The bars indicate the relative ambient temperature-adjusted and short-term emergency savings potential in each area. The drop lines show the number of transmission elements that would need temperature adjustments to realize two-thirds of the potential benefits in each area.

Figure A112: Area-Specific Savings Potential of Ratings Enhancement*Figure A113: Value of Unrealized Transmission Flows from Limit Control Derates*

MISO reduces transmission line limits in real time to manage congestion when factors such as non-conforming load, external loop flows, or wind volatility create uncertainty in transmission flows. MISO refers to this line limit adjustment as “limit control.” Using lower ratings increases production costs.

We analyzed whether MISO employed more conservative limit control derates on the transmission system than in prior years. Figure A113 also shows the congestion value of flows on constraints associated with those line deratings. The blue and red bars represent the sum of potentially unnecessary congestion costs for constraints derated below their true capacity. The blue bar represents a subset of constraints limited to 98 percent or below of the true line limit.

We calculate the blue bar by multiplying the difference between the quantity that can flow at 98 percent of the actual line limit and the flow at the limit control value (less than or equal to 98 percent) by the constraint’s shadow price. We then sum each constraint’s congestion value by month to produce the blue bars shown. Similarly, the red bars show the congestion effects of deratings between 98 and 100 percent of the line rating. We calculate the congestion cost by multiplying the difference in flows between 100 percent and 98 percent of the line limit by the constraint’s shadow price and then subtotalling by month.

Figure A113: Value of Unrealized Transmission Flows from Limit Control Derates

I. Operator Congestion Management Actions

This subsection addresses key actions MISO operators have taken to manage congestion. MISO operators take several manual actions to manage congestion on constraints that are difficult to control, including:

- Manually re-dispatching (MRD) a resource to a specific output level;
- Capping a resource's output;
- Increasing the TCDC values to allow the market to access additional relief on the constraint; and
- Changing the modeled limit on the constraint with the "limit control" parameter.

In this subsection, we summarize the frequency of each of these actions.

Figure A114: Manual Redispatch, Caps, and TCDC Actions

Although MRDs or caps produce a predictable effect, increasing the TCDCs on an unmanageable constraint tends to be the preferred action because it allows the dispatch model to acquire the lowest-cost relief on the constraint and price that relief in the real-time market. In contrast, MRDs and caps do not allow real-time market prices to reflect the costs of the relief these manual actions provide. In addition, MRDs and caps expose MISO to make-whole payments (usually DAMAP) because the dispatch level is not consistent with the real-time prices. Those causing the congestion are not directly allocated the DAMAP.

Figure A114 summarizes, by quarter, the hours from Spring 2023 to Winter 2025/26 when operators employed these actions. The chart shows caps as unit-hours, MRDs as unit-hours, and TCDC actions as binding constraint-hours. Capped hours include only inefficient caps where the unit's marginal cost is less than the relevant LMP and the unit otherwise would have been economic. For all action types, the hours metric equals the total number of 5-minute intervals divided by 12. These intervals may be non-adjacent and may apply to different units. For example, if operators manually re-dispatch two units for 5 and 7 intervals, respectively, the chart displays one unit-hour. When practicable, we removed from the counted unit-hours some caps and MRDs that were part of an operating guide.

TCDC adjustments count an interval when MISO made an upward adjustment to either the first or second TCDC value from its base level, which is the lowest TCDC value used recently for that TCDC step and constraint. For the TCDC counts, the figure includes intervals when the constraint was simultaneously binding and the higher TCDC was in effect. The inset table also counts limit control reductions, which are intervals when limit control was lower than in the prior interval. This metric does not account for how long the limit control reduction remained in place.

Figure A114: Manual Redispatch, Caps, and TCDC Actions

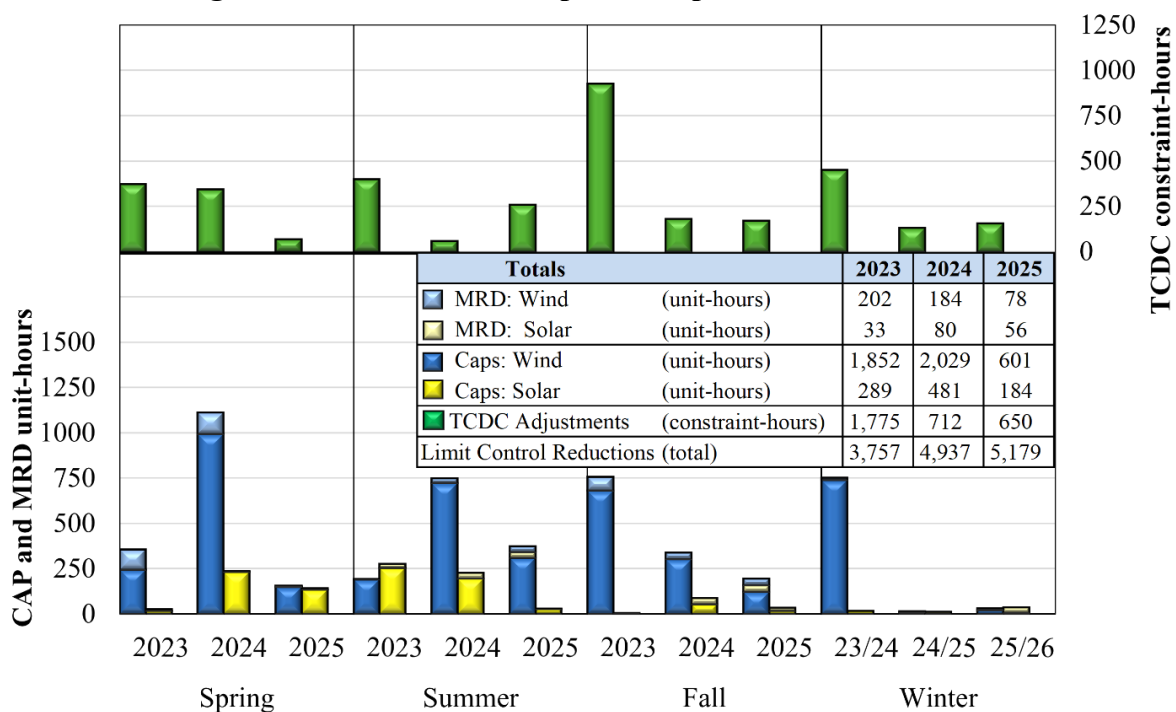


Figure A115: Limit Control Case Studies

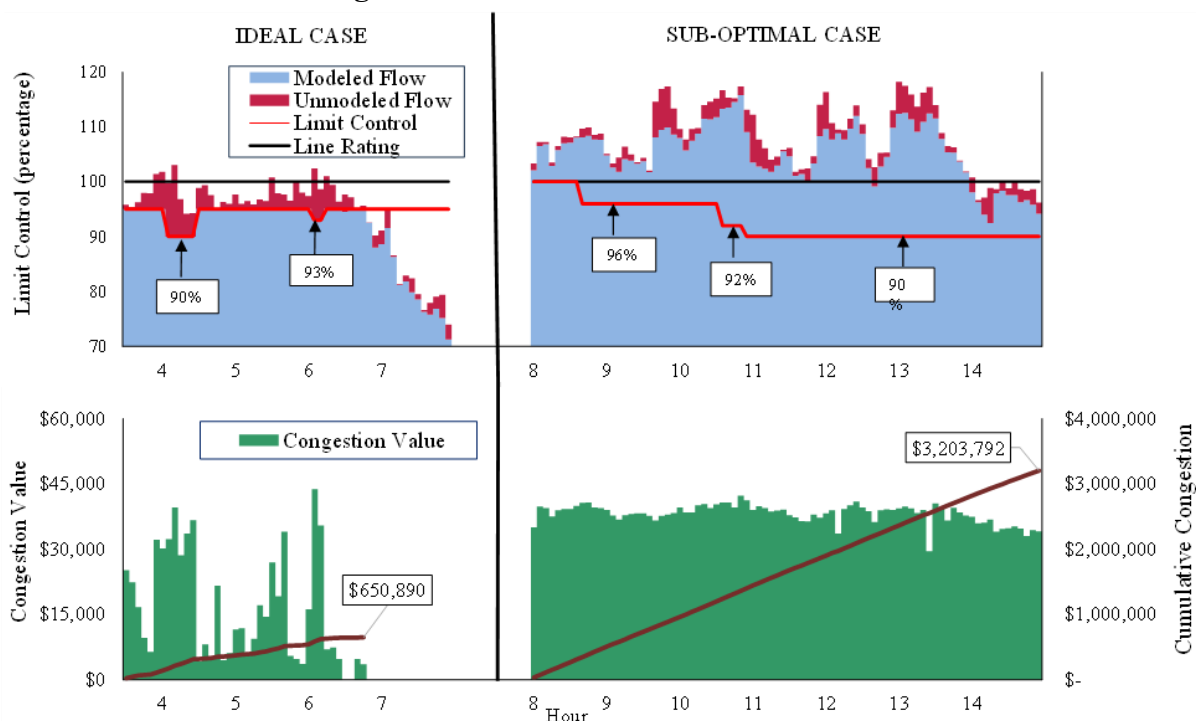
MISO operators use the limit control parameter to change a constraint's modeled limit in the real-time dispatch software. Limit control adjustments apply a percentage factor to transmission line ratings in real time to manage congestion, often reducing flows across the affected transmission elements. Because these adjustments can generate substantial inefficient congestion, we evaluate operators' use of limit control.

The primary reason to change a constraint limit in the dispatch model is to account for unmodeled flows. An “ideal” use of limit control derates a constraint when unmodeled flow rises and releases the derate when unmodeled flow falls. Unmodeled flow is the difference between the flows estimated by the state estimator model (i.e., actual flows) and the flows produced by the dispatch model. Accounting for unmodeled flows is important because they can cause constraint violations that threaten reliability. In this case, derating a constraint causes real-time dispatch to provide the needed relief on the constraint.

Figure A115 shows two uses of limit control. The left panel shows an ideal use of limit control, while the right panel shows a sub-optimal use. The left panel is ideal because changes in the limit control closely track changes in unmodeled flow. In the right panel, changes in the limit control do not track unmodeled flows but appear to address modeled flow violations. This is not an effective use of limit control.

In the top panel on both sides, the black line shows the actual line rating as a percentage of its capability. The red line shows the modeled limit, which operators often set by default at 97 to 98 percent of a line’s normal rating. The bars in the top charts show line flow as a percentage of the line’s capacity. The blue bars show the modeled flows, and the red bars show the positive deviation (i.e., unmodeled flows), the difference between the modeled flows and the state estimator flows. Together, the blue and red portions represent the actual flow on the line. When the combined blue and red bars exceed 100 percent, the transmission constraint is violated. If the blue bar meets or exceeds the red line, congestion costs are incurred regardless of whether the total bar height exceeds the actual line rating, shown by the black line. The bottom panel shows the modeled congestion dollars (shadow price times modeled flow) and the cumulative congestion cost on the right axis for the period shown in the chart.

Figure A115: Limit Control Case Studies



J. Other Key Congestion Management Issues

This subsection identifies three key opportunities to improve congestion management broadly.

Decommitting Resources that Cause Congestion

MISO does not decommit in real time units that it committed economically in the day-ahead market. When reliability requires MISO to decommit a day-ahead committed resource in real time, it manually redispatches the resource to 0 MW. This action ensures that resources remain eligible to recover DAMAP if the real-time LMP exceeds the unit's day-ahead LMP. Although an economic decommitment could create similar uplift exposure, decommitting a resource can in some cases alleviate significant congestion, reduce production costs, and likely result in no DAMAP.

Table A17: Case Studies Selected for LAC Decommitment Analysis

To assess the potential benefits of day-ahead economic decommitment, we performed case studies using MISO's LAC model. We defined each case study by an operating day, generator(s), and LAC case time. The units in each case study had a large shift factor on a constraint that was binding in real-time. We selected LAC case times using the first LAC case in which the resources' LMPs were negative for several intervals after the units completed their minimum runtimes. We modified the LAC input files to remove the day-ahead commitment for the units of interest; this allowed LAC to turn off the units in the case files.

We identified candidate case studies with negative LMPs in LAC for extended periods, often several hours. In one case study, the LMPs in LAC were negative for nearly the unit's entire commitment period. Each unit in our case studies had a large shift factor on a constraint that was binding in real-time. All LAC cases we evaluated were seven hours long, and case studies 1 and 2 were consecutive market days with the same units. Table A17 provides additional information about the selected case studies.

Table A17: Case Studies Selected for LAC Decommitment Analysis

Case Study	Number of Units	Unit Type	GSF	Season
1	2	Combined Cycle	44%	Summer
2	2	Combined Cycle	44%	Summer
3	2	Combustion Turbine	14%	Winter (storm event)
4	2	Combined Cycle	75%	Fall
5	2	Combined Cycle	8%	Winter

In our analysis, we re-solved LAC and allowed it to decommit the units of interest in each case study. In some case studies, LAC dispatched alternative units to higher schedules and committed additional units without a day-ahead schedule in the initial base case. The LAC model also recalculated shadow prices and LMPs in our case studies. The largest observed LMP change occurred in Case Study 2, where average LAC LMPs at the study units increased from -\$820 to \$35 as congestion on the constraint was eliminated.

Figure A116: LAC Decommitment Case Study Savings

We calculated savings in generator production costs, constraint violation costs, excess congestion fund (ECF) costs, and DAMAP costs for each case study. Figure A116 shows production cost savings in the violet bars, violation cost savings in the maroon bars, DAMAP savings in the green bars, and ECF savings in the light blue bar. We based production cost savings on offer data and the dispatch MWs from LAC. Production costs include hourly production costs and start-up costs for units that were on in LAC in both the base case and the test case.

We calculated violation costs for all active constraints using modeled flows and shadow prices from the LAC model. In Case Study 1, violation costs increased because the target constraint was not in violation in the LAC base case. The LAC reruns for this case produced violations on other constraints, which increased total violation costs. Violation costs decreased in the other four case studies.

We calculated ECF costs for the base cases using real-time data from the market day. We estimated ECF costs using the real-time data and the difference in constraint flows between the base and test cases. We calculated ECF savings by multiplying the estimated real-time flow for the test case by the test case shadow price in LAC.

We estimated the DAMAP the units would have received because of the decommitment in LAC. In each case study, allowing LAC to turn off the unit reduced congestion and increased RT LMPs. This increased DAMAP costs because the turned-off units would be eligible for uplift at the higher LMPs. Instead of buying out of a DA schedule at sustained negative LMPs, the unit buys out of its day-ahead schedule at positive LMPs. We calculated DAMAP costs only for the units of interest in each case study.

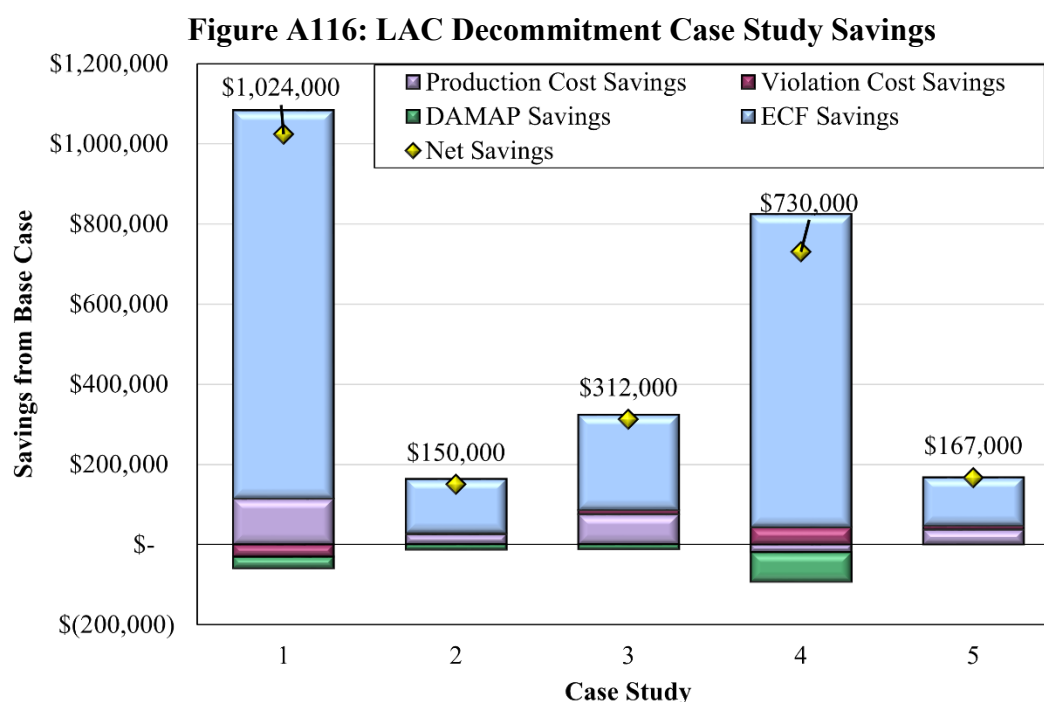
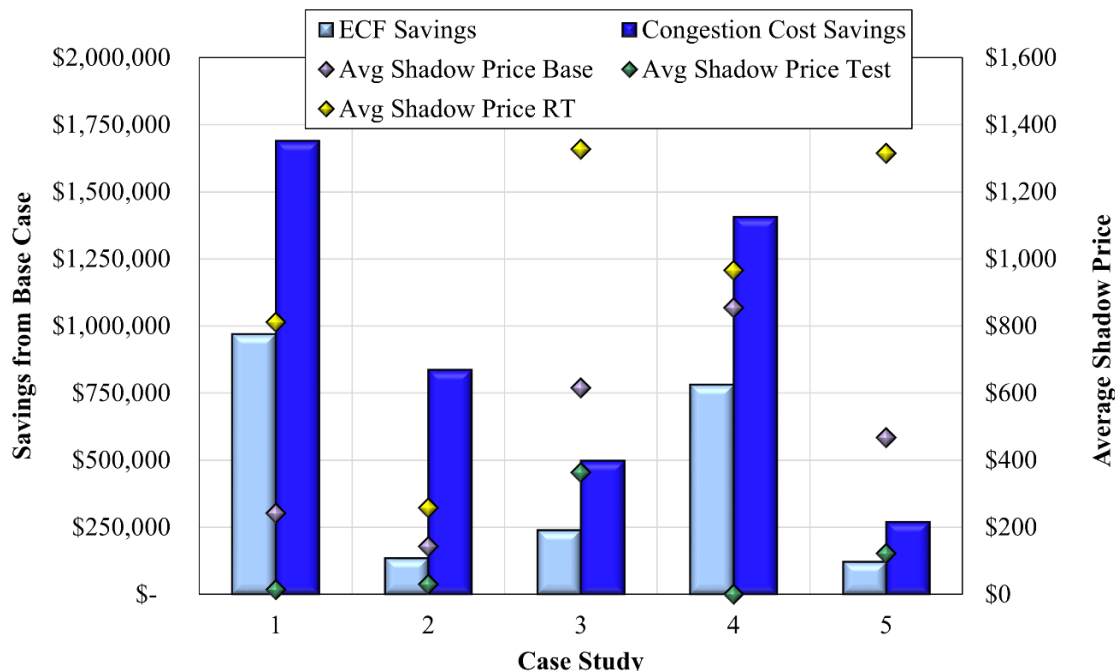


Figure A117: Congestion Savings and Shadow Price Changes in Case Studies

In addition to the cost savings, we calculated the overall congestion cost savings for each case study. This is not an actual cost that MISO pays, but it can be interpreted as a measure of how well the constraint is managed. We calculated congestion costs by multiplying the shadow price by constraint flows for all constraints in the market at the time. Figure A117 shows the overall congestion costs (dark blue) and ECF savings (light blue) for the main constraint of interest in each case study. The figure also shows the average real-time shadow price (yellow diamonds), base case LAC shadow price (light purple diamonds), and test case LAC shadow price (green diamonds) at the units included in each case study on the right-hand axis. We averaged all shadow prices over the seven-hour LAC case study duration.

We include the average real-time shadow prices to compare them with the average shadow prices in LAC. In every case, the real-time shadow price on the main constraint was significantly higher than the LAC value. In case studies 1, 3, and 5, the real-time shadow price was more than double the LAC base case shadow price. These differences indicate that the constraints were binding more strongly in real-time than in LAC.

Overall, congestion savings ranged from \$270,000 to \$1,688,000 over seven hours. In two case studies, turning off the case study units eliminated all congestion on the affected constraint in LAC, reducing the shadow price to \$0. More modest reductions in shadow price still produced hundreds of thousands of dollars in congestion savings.

Figure A117: Congestion Savings and Shadow Price Changes

In 2025, we ran additional case studies. One found \$25 million in cost savings from decommitting two units during a period of high congestion. ECF savings were high in this case study because the top step of the constraint's TCDC was \$5,000 per MWh at the time.

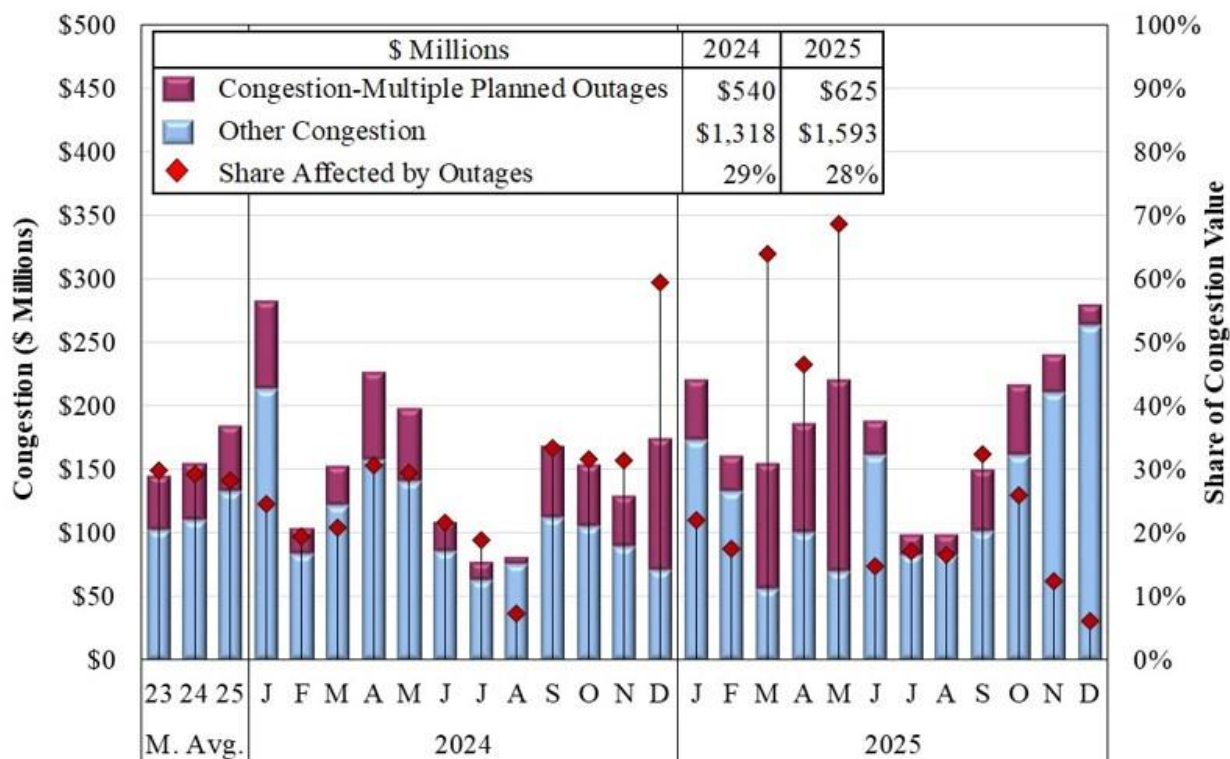
Coordinating Outages that Cause Congestion

Generators take planned outages to conduct periodic maintenance, evaluate or diagnose operating issues, and upgrade or repair various systems. Similarly, transmission operators conduct periodic planned maintenance on transmission facilities, which generally reduces system transmission capability. MISO evaluates only the reliability effects of planned outages, including contingency and stability studies. Different participants may independently schedule generation and/or transmission outages in a constrained area. Absent a reliability concern, MISO does not have tariff authority to deny or postpone a planned outage, even when it will likely have substantial economic effects.

Figure A118: Congestion Affected by Multiple Planned Generation Outages

Figure A118 provides a high-level evaluation of how uncoordinated planned outages may affect congestion. It shows the real-time congestion value incurred from January 2024 through December 2025. We identify the portion of congestion on constraints substantially affected by two or more planned generation outages that affected at least 10 percent of the constraints' flows. The maroon bars represent congestion attributable to multiple planned generation outages, and the blue bars indicate total congestion not attributable to concurrent planned generation outages. The diamonds indicate the percentage share of congestion due to concurrent planned generation outage.

**Figure A118: Congestion Affected by Multiple Planned Generation Outages
2024–2025**



VI. RESOURCE ADEQUACY

This section examines supply and demand conditions in MISO. In 2025, 177 market participants either owned generation resources totaling 179.6 GW of nameplate capacity or served load in the MISO market.²⁹ This group includes investor-owned utilities, municipal and cooperative utilities, and independent power producers. MISO serves as the reliability coordinator for an additional 15 GW of resources, which we exclude from this analysis unless noted. Manitoba Hydro is the largest non-market coordinating member. It does not submit bids or offers but may schedule imports and exports.³⁰

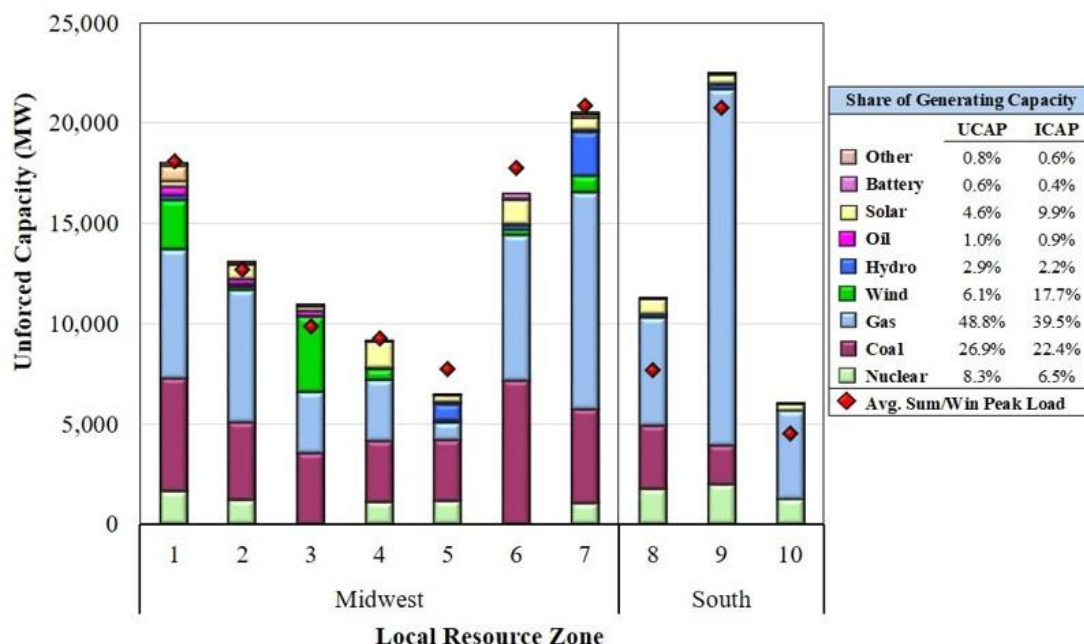
MISO’s reliability coordination function includes three regions: (1) North (all or parts of Iowa, Minnesota, Montana, North Dakota, and South Dakota); (2) Central (all or parts of Illinois, Indiana, Kentucky, Michigan, Missouri, and Wisconsin); and (3) South (all or parts of Arkansas, Louisiana, Mississippi, and Texas). “Midwest” refers to the North and Central regions together.

A. Regional Generating Capacity

Figure A119: Distribution of Existing Generating Capacity

Figure A119 shows the distribution of UCAP for generating resources in operation at the end of 2025 by zone and fuel type. The red diamonds denote the average of summer and winter peak load in each zone. The inset table compares each fuel type’s UCAP and ICAP shares.

**Figure A119: Distribution of Existing Generating Capacity
By Fuel Type and Zone, 2025**



²⁹ As of May 2025, MISO membership totaled over 600 Certified Market Participants including power marketers, state regulatory authorities, and other stakeholder groups.

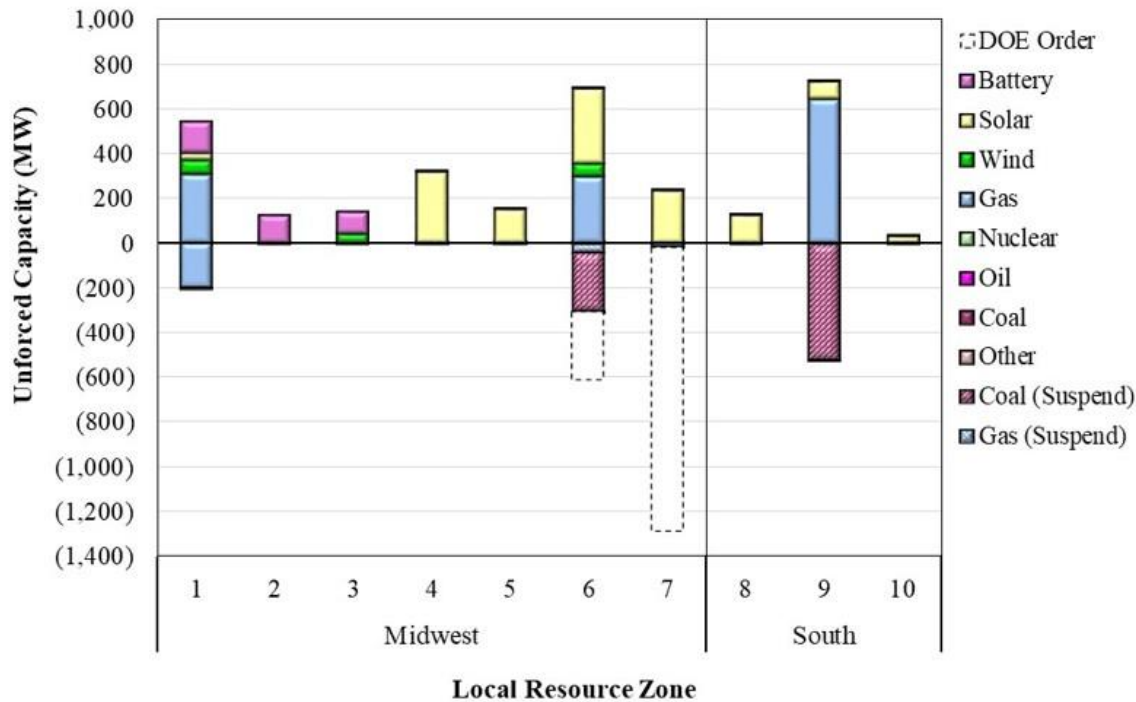
³⁰ Manitoba does submit a limited amount of offers under the External Asynchronous Resources (EAR) procedure, which permits dynamic interchange with such resources through the five-minute dispatch.

B. Changes in Capacity Levels

Figure A120: Distribution of Additions and Retirements of Generating Capacity

Figure A120 shows the change in UCAP values in each zone during 2025 from retirements, additions, and interconnection changes. The hatched area represents capacity that entered long-term suspension in 2025 and is not expected to return to the market. The shadow bars indicate capacity planned for retirement that the Department of Energy ordered to stay online.

Figure A120: Distribution of Additions and Retirements of Generating Capacity
2025, By Fuel Type and Zone



C. Planning Reserve Margins and Summer Readiness

Table A18: Summer 2026 Planning Reserve Margins

This subsection summarizes MISO capacity levels and their adequacy to satisfy forecasted summer 2026 peak loads. We align our Base Case planning reserve level with MISO’s assumptions in its 2026 *Summer Readiness Workshop*, including a 1,900 MW transfer limit³¹ between MISO South and MISO Midwest. We also provide four additional scenarios, described in detail below, that we believe more realistically represent MISO’s summer peak reliability margin.

MISO’s reliability assessment is designed to ensure an adequate supply margin across the forecasted summer peak and maintain the NERC reliability standard that the risk of loss of load

³¹ We do not think this is an accurate assumption based on real-time operations, but we include this assumption to align our Base Case with MISO’s Base Case.

does not exceed one day in ten years. The Loss of Load Expectation study determines the Planning Reserve Margin Requirement (PRMR) and currently assumes that no planned outages are scheduled across the summer peak and that all LMRs and emergency-only resources can be fully utilized if MISO declares an emergency.

The reserve margins in the table generally reflect: (a) peak-load forecasts under normal conditions;³² (b) normal load diversity; (c) average forced outage rates; (d) expected wind and solar generation based on their accreditation; and (e) full response from imports and Demand Response (DR) resources that cleared the PRA (behind the meter generation, interruptible load, and direct controllable load management).

Table A18 shows our base case and four alternative scenarios that examine how short-notice planned outages, variations in solar contribution during the evening ramp, and unusually hot temperatures affect MISO's planning reserve margins. We include a conservative measure of historical non-capacity imports during the summer peak to calculate an expected margin. Table A18 includes the following cases:

- Column 1: *Base* scenario assumes a 1,900 MW transfer limit between the South and Midwest, that MISO can access all DR in an emergency, and that summer planned outages are limited to those scheduled and approved by April 1, 2026. We replace the UCAP-based Planning Reserve Margin (PRM) for demand response resources with an ICAP-based PRM to align with Summer Assessment reporting on an ICAP basis. For wind, we use the wind ELCC value and apply an ICAP-based PRM to assume a wind ICAP value. For solar resources, we use the accredited value based on historical performance during hours ending 15 through 17, or 50 percent for new resources.
- Column 2: *Realistic Base* assumes transfer capability between MISO South and Midwest will be 2,300 MW, consistent with operations, and that planned and unreported outages and derates will match the summer on-peak average of the previous three years. This scenario also assumes that MISO can access only 75 percent of demand response resources in an emergency, consistent with historical observations.
- Column 3: *Evening Ramp* adjusts the assumptions in Column 2 for load, solar output, transfer limit, and firm capacity imports to reflect evening ramp conditions (approximately 7 pm). High-load conditions during periods of declining solar output are expected to become more frequent and significant over time, reinforcing the need for adequate dispatchable resources to reliably meet system needs.
- Columns 4 and 5: *High Temperature* cases adjust load and unforced outages in columns 2 and 3 to reflect hotter-than-normal summer peak conditions that could prevail in a "90/10" case (i.e., a 90 percent chance load is lower and a ten percent chance load is higher, meaning it should occur only one year in ten).

³² Expected peak load in reserve margin forecasts are generally median "50/50" forecasts (i.e., there exists a 50 percent chance load will exceed this forecast and a 50 percent chance it will fall short).

Table A18: Summer 2026 Planning Reserve Margins

	Base Scenario	Alternative IMM Scenarios ¹⁾			
		Realistic Base Scenario	Realistic Evening Ramp Scenario	High Temperature Cases	
				Realistic Scenario	Evening Ramp Scenario
Load					
Base Case	125,531	125,531	125,531	125,531	125,531
Load Adjust			(4,773)	6,339	1,325
Wind & Solar					
Internal Wind & Solar	17,961	17,961	8,485	17,961	8,485
BTM Wind & Solar	1,359	1,359	342	1,359	342
Net-Load (MW)	106,211	106,211	111,931	112,550	118,029
Conventional Generation					
Internal Conventional Generation Excluding Exports	123,731	123,731	123,731	123,731	123,731
BTM Conventional Generation	3,361	3,361	3,361	3,361	3,361
Unforced Outages and Derates ²⁾	(1,707)	(8,259)	(8,259)	(15,859)	(15,859)
Adjustment due to Transfer Limit	(11,579)	(4,627)	(1,472)	(650)	-
Total Conventional Generation (MW)	113,806	114,206	117,361	110,583	111,234
Imports and Demand Response ³⁾					
Demand Response (ICAP)	9,698	7,274	7,274	7,274	7,274
Firm Capacity Imports	4,729	4,729	4,279	4,729	4,279
Margin (MW)	22,023	19,998	16,983	10,036	4,758
Margin (%)	17.5%	15.9%	14.1%	7.6%	3.8%
Expected Capacity Uses and Additions					
Expected Forced Outages ⁴⁾	(6,591)	(7,338)	(7,338)	(7,338)	(7,338)
Non-Firm Net Imports in Emergencies	2,867	2,867	2,867	2,867	2,867
Expected Margin (MW)	18,298	15,527	12,512	5,565	287
Expected Margin (%)	14.6%	12.4%	10.4%	4.2%	0.2%

1) All IMM scenarios assume 75% response from DR. Evening Ramp Scenario reduces solar by approximately 10 GW and firm capacity imports by 450 MW.

2) Base scenario shows approved planned outages for summer 2026. Realistic cases use historical averages during peak summer hours. High temp. cases are based upon MISO's 2026 Summer Readiness.

3) Cleared amounts for the Summer Season of the 2026/2027 planning year.

4) Base scenario assumes 5% forced outage rate for internal, BTM, and external generation (excluding wind and solar). Alternative cases use historical average forced outages/derates during peak summer hours for internal generation.

D. Long-Term Economic Signals

In this subsection, we summarize the long-term economic signals produced by MISO's energy, ancillary services, and capacity markets. Our evaluation uses the "net revenue" metric, which measures the revenue that a generator would earn above its variable production costs if it were to operate only when revenues from energy and ancillary services exceeded its costs. Well-designed markets should provide sufficient *expected* net revenues to finance new investment when additional capacity is needed. However, random factors in each year (e.g., weather conditions, generator availability, transmission topology changes, outages, or changes in fuel prices) can cause the net revenues to be higher or lower than the equilibrium value.

Our analysis examines the economics of two types of new units: a natural gas CC unit with an assumed heat rate of 6,600 Btu per kWh and a natural gas CT unit with an assumed heat rate of

9,905 Btu per kWh.³³ The net revenue analysis includes assumptions for variable operations and maintenance (VOM) costs, fuel costs, and expected forced outage rates.

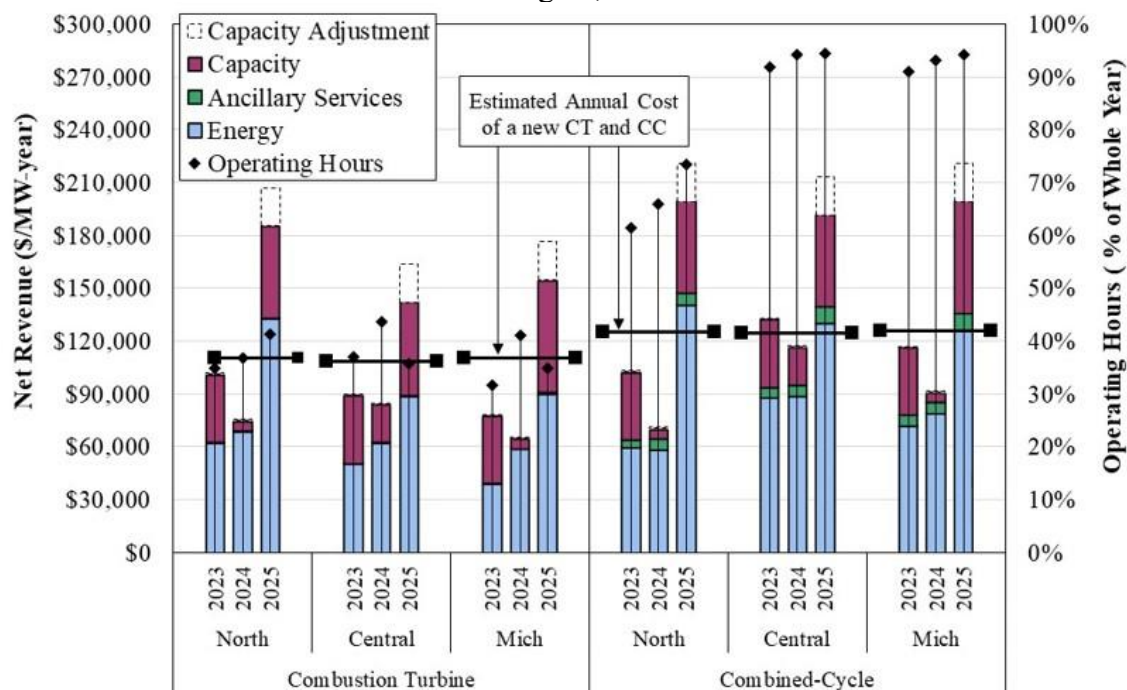
Figure A121 and Figure A122: Net Revenue Analysis

The next two figures compare the net revenue plus capacity market revenue that new CC and CT units would have received in different MISO regions with the revenue required to support new investment in these units. To determine whether net revenue levels would support investment in new resources, we first estimate a new unit's annualized cost. The figures show this estimated annualized cost, which is the annual net revenue a new unit would need to earn in MISO wholesale markets to make the investment economic. The figure shows the estimated Cost of New Entry (CONE) for each unit type as horizontal black segments, based on data from the U.S. Energy Information Administration (EIA) and various financing, tax, inflation, and capital cost assumptions.

Combined-cycle generators run more frequently and earn more energy rents than simple-cycle CTs because CC units have substantially lower production costs per MWh. Therefore, estimated energy net revenues for CC generators tend to be substantially higher than for CT generators. Conversely, capacity and ancillary services revenues typically account for a larger share of a CT's net revenues. Capacity requirements and import and export limits in the Planning Resource Auction (PRA) vary by zone, so capacity revenues vary with the clearing price in each zone. The figure shows estimated net revenues for these two resource types in different MISO regions as stacked bars. The diamonds show the estimated operating hours of each unit type during the year. For comparison, we reproduce the Central Region results on the MISO South figure.

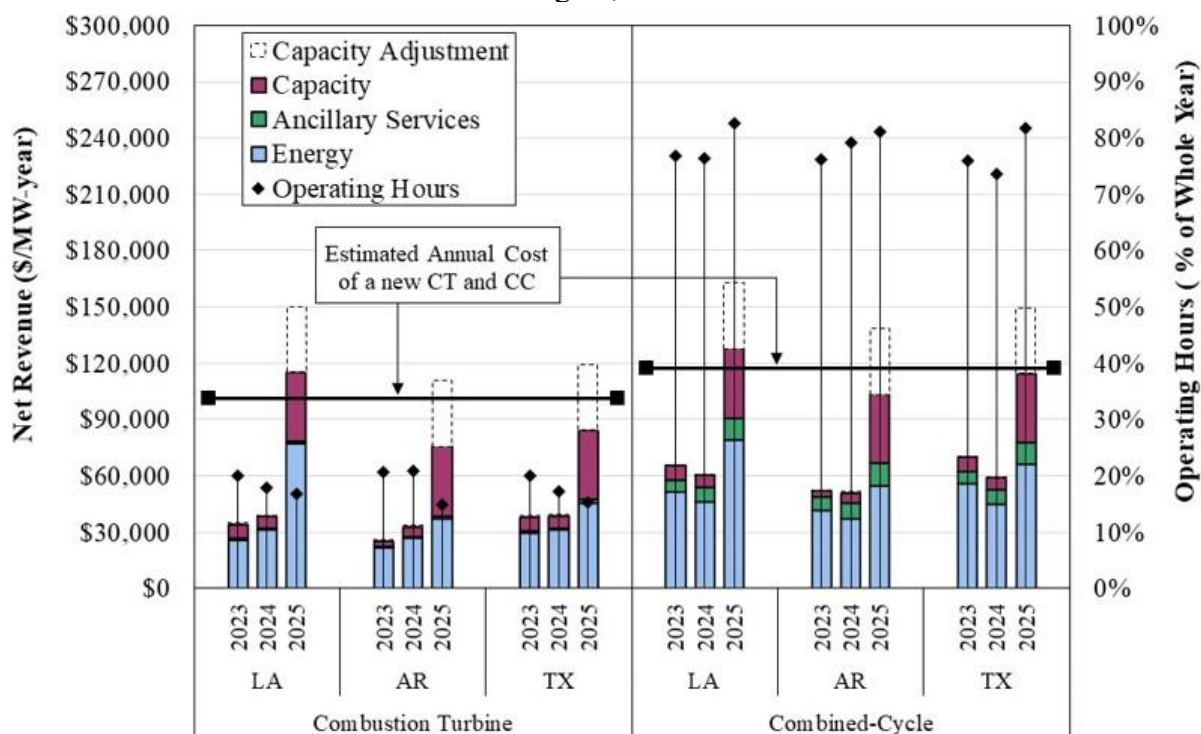
Figure A121: Net Revenue Analysis

Midwest Region, 2023–2025



³³ These assumptions are used in the 2020 EIA Annual Energy Outlook.

Figure A122: Net Revenue Analysis
South Region, 2023–2025



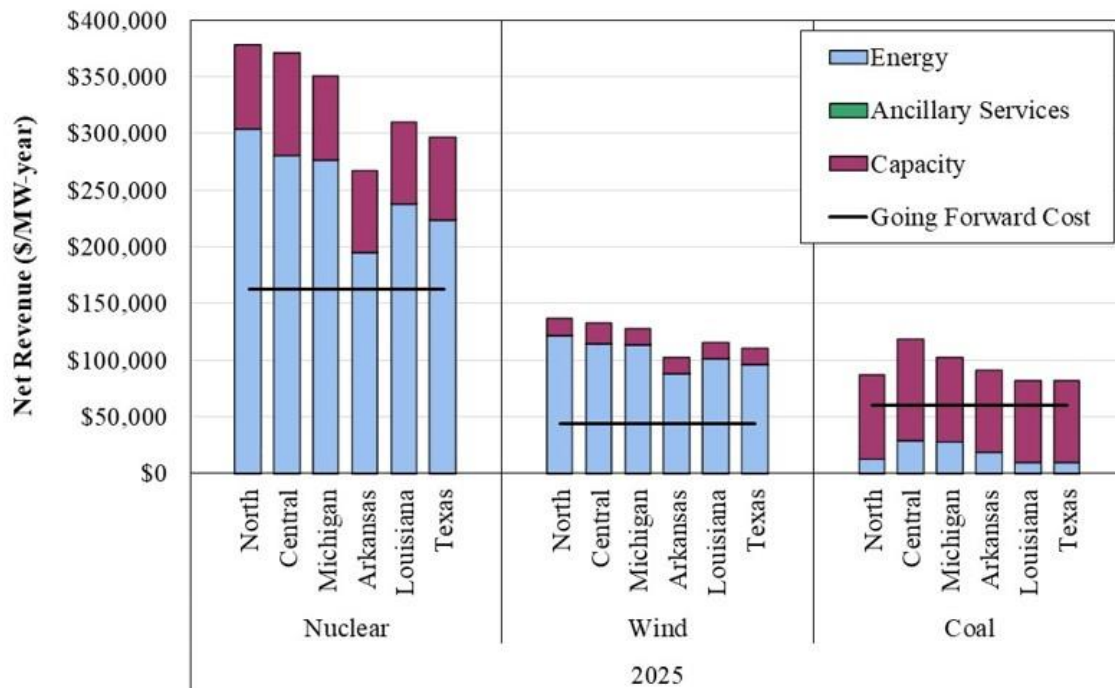
E. Existing Capacity at Risk Analysis

Prior to 2022, MISO had a large capacity surplus. When resources cannot recover their fixed costs in the long run, they may be suspended or retired. MISO's capacity surplus dwindled in recent years as older baseload units with higher fixed costs entered long-term suspension or retired. Falling natural gas prices and the vertical demand curve that MISO's capacity market used through the 2024–2025 Planning Year largely drove this trend and understated capacity prices. MISO implemented a downward-sloping reliability-based demand curve (RBDC) in its PRA beginning with the 2025–2026 Planning Year. Most new capacity entering MISO is either gas-fired generation or solar resources.

Figure A123: Capacity at Risk by Technology Type

We analyze capacity at risk of long-term suspension or retirement for three technology types in MISO: nuclear, wind, and coal. We compare annual resource net revenues with the technology-specific Going Forward Costs (GFCs) defined in Module E of MISO's Tariff. For coal unit net revenue, we use the median unit's two-year historical net revenues in the relevant resource adequacy zone. For nuclear, we assume a 2,156 MW unit with VOM costs of \$10 per MWh that runs year-round. For wind, we assume a 200 MW unit with \$0 marginal costs and a 30 percent capacity factor. Figure A123 illustrates this analysis. The blue bars indicate revenues the resources received through the energy markets, and the maroon bars represent capacity market revenues on a dollar per MW-year basis. Alternative wind capacity values are much smaller than coal and nuclear because wind receives a much smaller UCAP value for its ICAP than conventional resources do.

Figure A123: Capacity at Risk by Technology Type
2025



F. Capacity Market Reforms

Figure A124 and Figure A125: Estimated Capacity Replacement Settlement Prices

In this year's report, we propose the Capacity Replacement Settlement, a transparent, market-based alternative to the current capacity replacement rules. To estimate capacity replacement prices under changing system conditions, we first formed daily capacity resettlement demand curves (CRDCs). These curves mimic the PRA's RBDCs, which reflect the marginal reliability benefit of each megawatt of capacity.

The RBDCs and CRDCs begin with a flat plateau, where the marginal reliability impact (MRI) function is capped at a maximum. We set that maximum for the CRDCs at ten times the applicable regional and seasonal PRA's ACP. That plateau extends to a daily quantity of projected peak load, net of renewable generation, from the prior day's Multi-Day Operating Margin (MOM) Report, multiplied by the applicable Planning Reserve Margin (PRM). Beyond that point, the CRDCs' slopes approximate those of the corresponding RBDC to reflect MISO's MRI estimates. The CRDCs' end points are quantity-price pairs also derived from the RBDCs. For supply, we used a vertical supply curve formed by the resources committed in the day-ahead market (excluding renewables and demand response), plus an RDT assumption of 2,250 MW south-to-north and 2,700 MW north-to-south, plus seasonal import assumptions for the Midwest and the MISO-wide analysis.

We used the intersection of those illustrative supply and demand curves to estimate the prices that would have cleared the capacity replacement market each day from March 1, 2025 through

February 28, 2026. Figure A124 shows the Midwest prices, and Figure A125 shows the South prices. We used a lower scale for the South figure's vertical axis.

Figure A124: Estimated Midwest Capacity Replacement Settlement Prices
March 2025 – February 2026

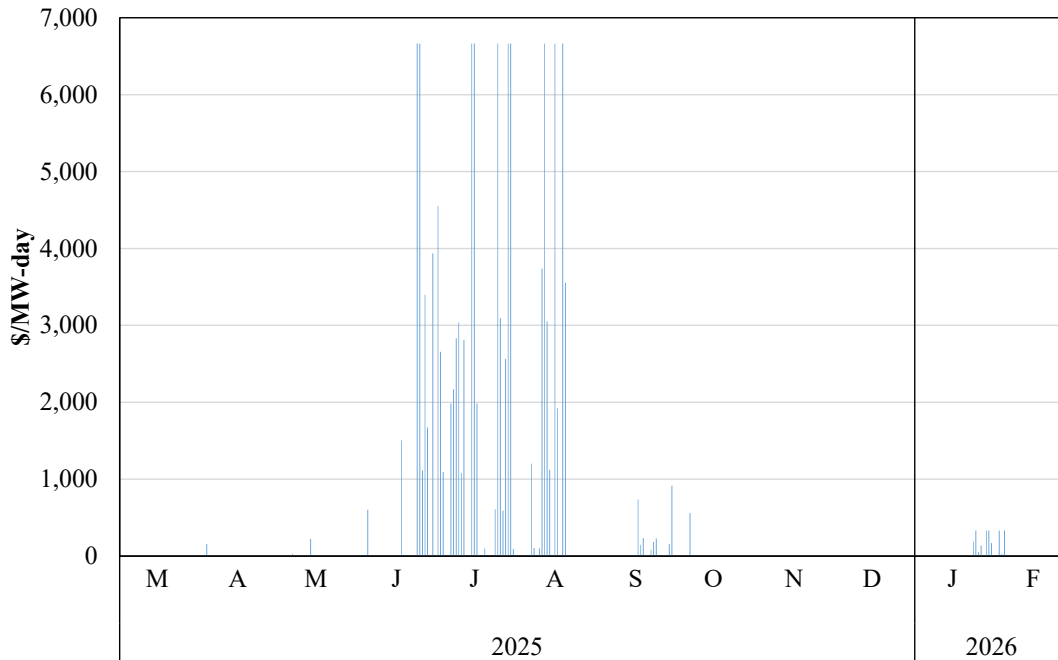
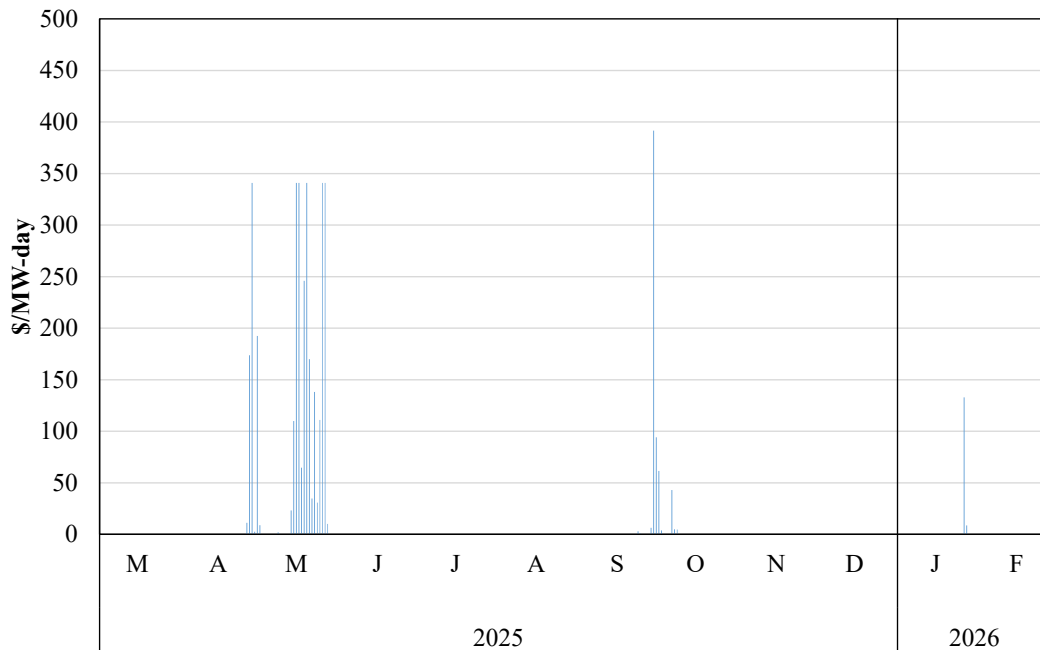


Figure A125: Estimated South Capacity Replacement Settlement Prices
March 2025 – February 2026



VII. EXTERNAL TRANSACTIONS

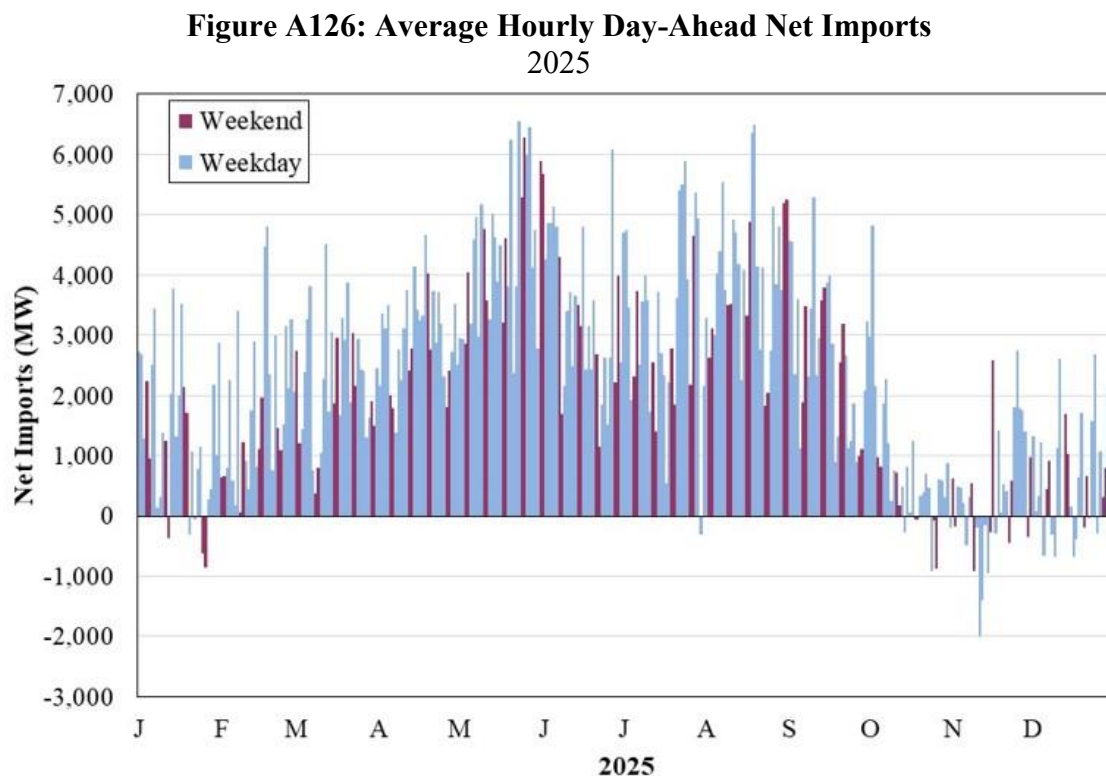
MISO is a net importer of power during nearly all hours and seasons. Because MISO relies on imports, the scheduling and pricing of interchange transactions can substantially affect the performance and reliability of its markets.

Imports and exports can be scheduled every 15 minutes, although schedules must be submitted 20 minutes before the transaction period starts. On October 15, 2013, the scheduling notification period was reduced from 30 minutes to 20 minutes to satisfy FERC's Order 764 requirements. Participants must reserve ramp capability to schedule a transaction, and MISO will refuse transactions that place excessive ramp demand on the system. On October 3, 2017, MISO implemented Coordinated Transaction Scheduling (CTS) with PJM, which allows market participants to schedule transactions based on the forecasted price spread between markets. This section reviews the magnitude of interchange and the efficiency of the scheduling process.

A. Overall Import and Export Patterns

Figure A126 to Figure A129: Average Hourly Imports

The following four figures show daily average hourly net imports (i.e., imports net of exports) scheduled in the day-ahead and real-time markets, in total and by interface. The first figure shows total net imports in the day-ahead market and distinguishes between weekdays (when demands are greater) and weekends.



The second figure shows real-time net imports and changes from day-ahead net import levels. When net imports decline in real time, MISO may need to commit peaking resources. The third and fourth figures show these data by interface.

**Figure A127: Average Hourly Real-Time Net Imports
2025**

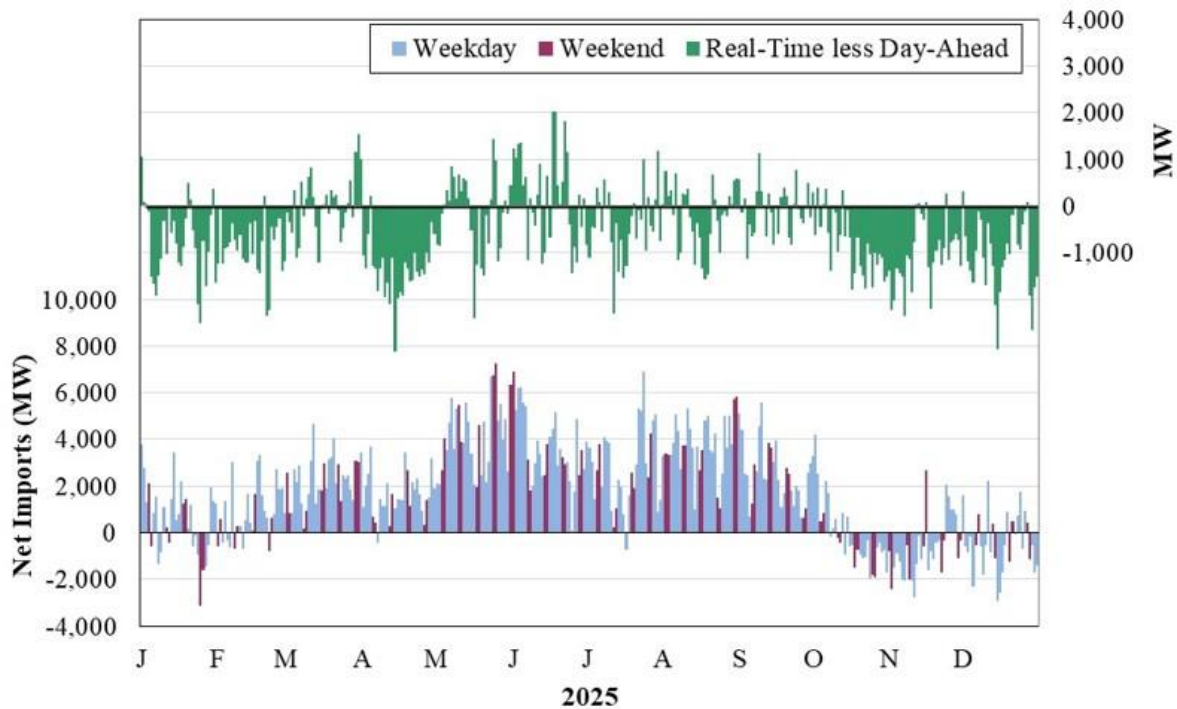


**Figure A128: Average Hourly Day-Ahead Net Imports
2025, by Interface**

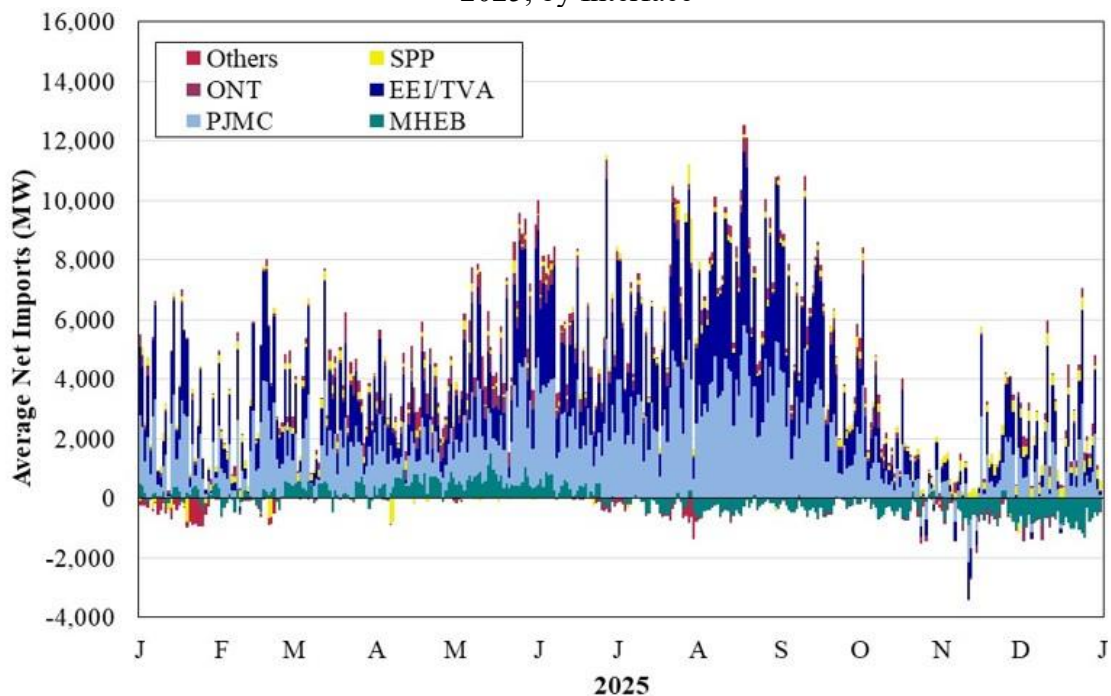
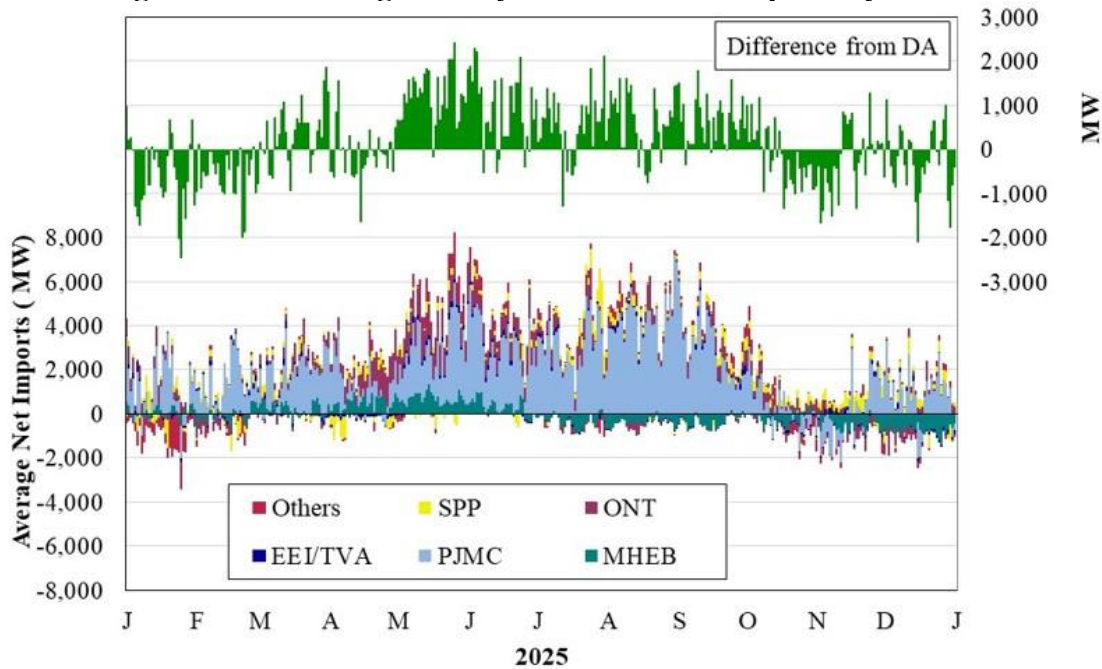


Figure A129: Average Hourly Real-Time Net Imports by Interface*Figure A130 and Figure A131: Average Hourly Real-Time Net Imports by Interface*

The next two figures examine net real-time imports on the MISO's interfaces with PJM and Canada. Differences in LMPs between areas facilitate interchange between MISO and PJM. This is the most active interface, supporting more than 6 GW per hour. Figure A130 shows the average net imports and wheels scheduled across the MISO-PJM interface by hour of day in 2024 and 2025, along with the standard deviation of net imports.

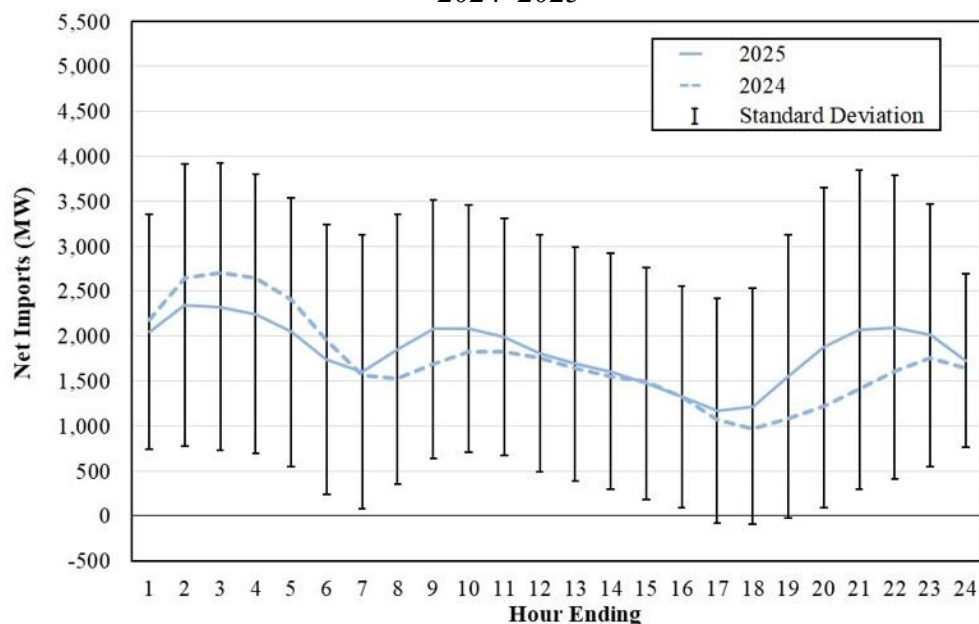
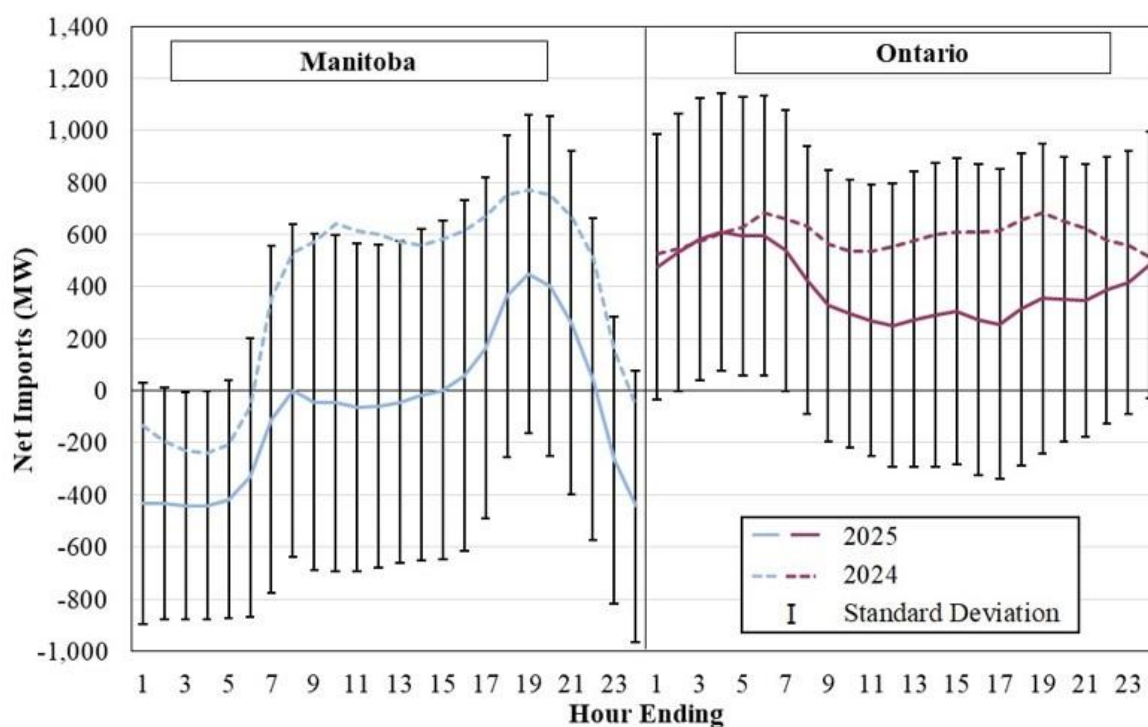
**Figure A130: Average Hourly Real-Time Net Imports from PJM
2024–2025**

Figure A131 shows these results for the two Canadian interfaces.

**Figure A131: Average Hourly Real-Time Net Imports from Canada
2024–2025**



B. Coordinated Transaction Scheduling

CTS allows market participants to submit offers to schedule imports or exports between the RTOs within the hour if the forecasted spread between the MISO and PJM real-time interface prices exceeds the offer price. Participants can submit multi-part offers with separate prices for increasing quantities 75 minutes before the specific interval. Offers then clear if they are less than the forecasted spread in interface prices 30 minutes before the interval. CTS transactions settle based on real-time interface prices.

Figure A132: CTS Versus Traditional NSI Scheduling

Since its inception in October 2017, CTS has attracted very little participation. To determine how transaction fees and forecasting errors affect CTS, we compared (a) a scheduling strategy using CTS offers with (b) a strategy using short-lead time transactions scheduled 30 minutes ahead (i.e., the traditional means of scheduling transactions).

Excluding transaction charges, CTS transactions would be more profitable if the mechanism operated effectively because participants can submit an offer price. In contrast, the traditional scheduling mechanism requires participants to submit transactions that are not price-sensitive and that are based on their expectations of the price spreads that will exist when the transactions are flowing.

Figure A132 compares 1 MW CTS transactions offered at target spreads from \$0 to \$20 in \$5 increments with 1 MW short-lead scheduled transactions initiated when the actual real-time interface price spread 30 minutes before the transaction exceeded the applicable target spread. This analysis applies to both imports and exports. All offered CTS exports incur reservation charges of \$0.80 per MWh and an additional \$1.75 per MWh if they clear. Offered CTS imports incur reservation charges of \$0.28 per MWh and an additional \$0.55 per MWh if they clear. Cleared short-lead transactions incur the total costs listed above, based on direction. CTS transactions tend to incur much higher costs because they pay a reservation charge for every MW bid/offered even though a very small share clear.

In Figure A132, the solid bars show gross profits (\$ per MWh) for each strategy, and the diamonds show net revenues (\$ per MWh), including reservation and other market charges.

Figure A132: CTS Versus Traditional NSI Scheduling
January–November, 2025

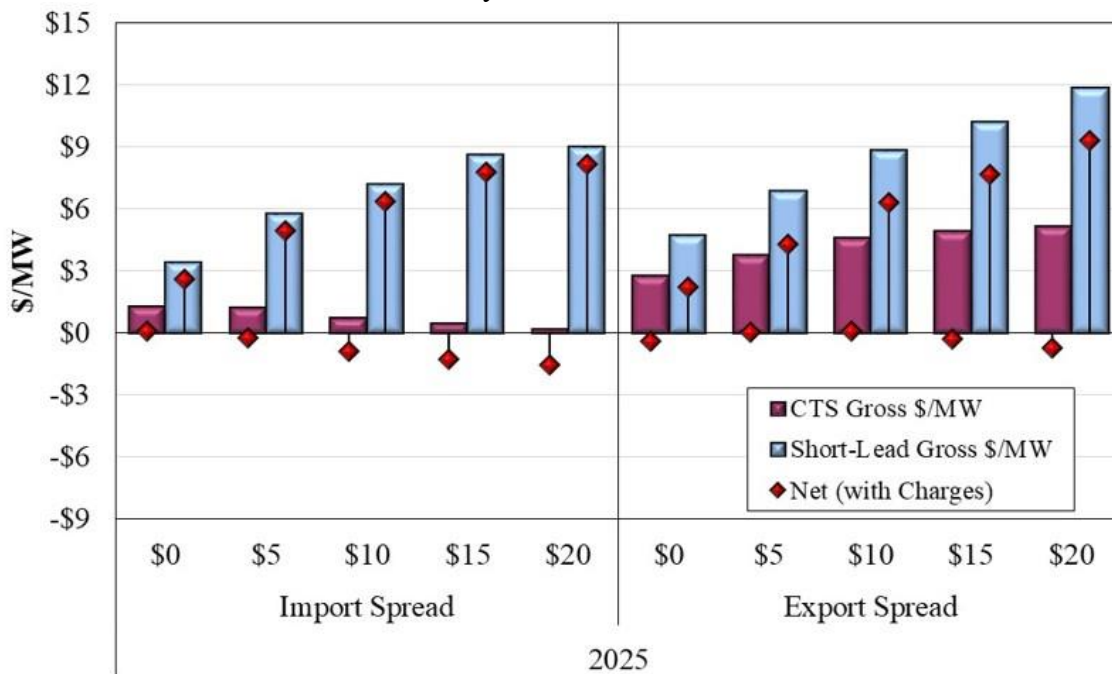


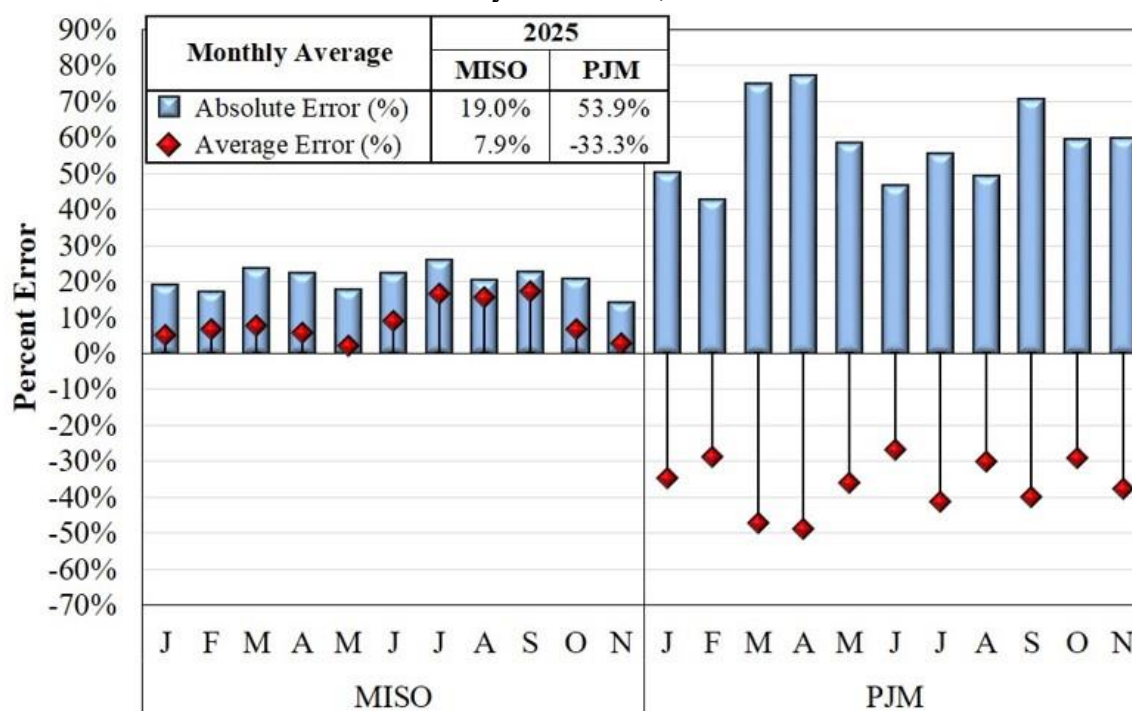
Figure A133: MISO and PJM CTS Forecast Errors

CTS use has been limited because of persistent forecasting errors in MISO and PJM. We measured the difference between the actual LMP and the forecasted price. Figure A133 shows the monthly results as a share of average LMPs in average and absolute average terms.

The red diamonds represent the monthly average difference between the real-time LMPs at the respective RTOs' interface (five-minute prices averaged to 15-minute intervals) and the 15-minute forecasted interface prices used for CTS, expressed as a percentage relative to average real-time LMPs. A positive error means the forecasted prices were, on average, lower than real-time LMPs, while a negative error means the forecasted prices were higher. The blue bars show the same error calculation in absolute terms. The inset table shows the average of these error calculations across all months.

Figure A133: MISO and PJM CTS Forecast Errors

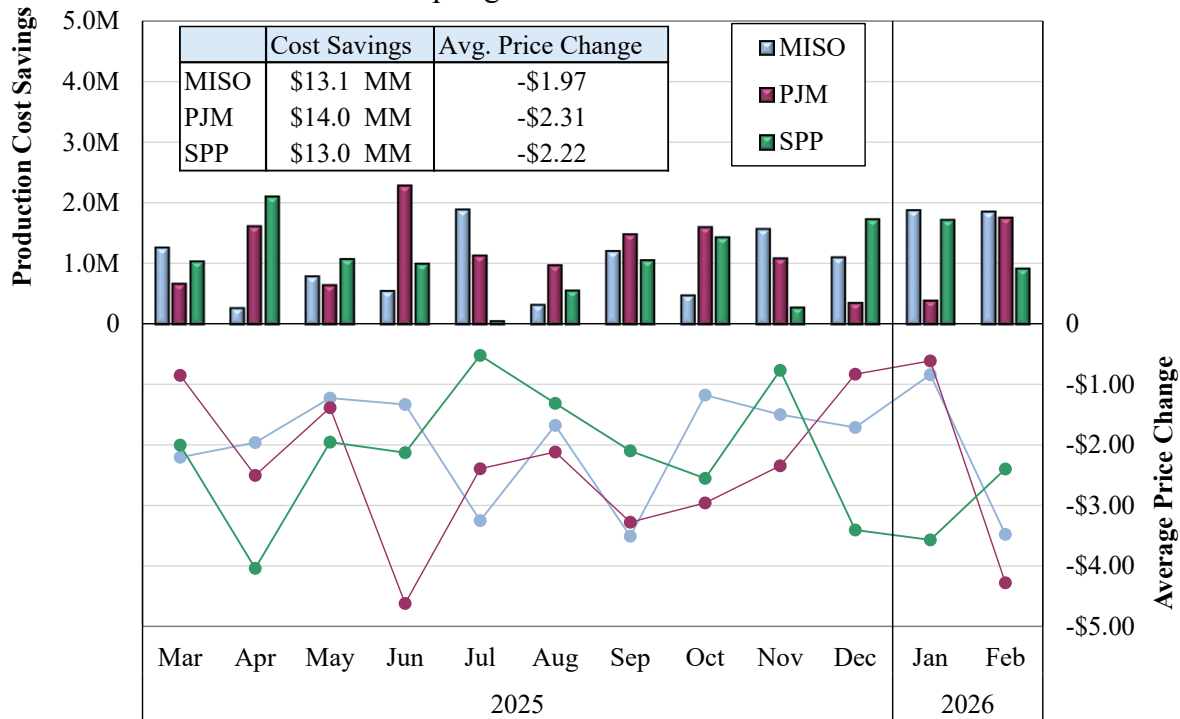
January–November, 2025

*Figure A134: Interchange Optimization Benefit Estimate*

As an alternative to CTS, we evaluated a Security Constrained Economic Dispatch (SCED)-based Interchange Optimization (IO) framework that would use the alternative load-offset cases already solved in each RTO's five-minute real-time dispatch process. Under this approach, participating RTOs would exchange standardized summaries of their evaluated SCED scenarios, including the load offset, production cost, marginal energy component of LMP, interface LMPs, and the initially selected case. A clearing step would then compare feasible scenario pairings across markets and identify interchange adjustments that reduce combined production costs, satisfy transfer limits, and preserve a configurable minimum export margin.

Because historical alternative SCED scenario results were not available for PJM and SPP, this screening analysis estimated external price-response curves as a proxy for how neighboring-market prices and production costs would change under alternative interchange levels. The analysis used historical MISO, PJM, and SPP market results, MISO alternative-case prices and production costs, matching offset volumes, a maximum export of 400 MW, and a minimum export margin of \$5 per MWh. The resulting benefits are measured as production-cost savings and estimated load-cost impacts, with settlements modeled so that the importing market is revenue neutral and the exporting market is compensated through the export margin. Figure A134 summarizes the estimated production cost savings and average price decreases in the three markets in the 12 months from Spring 2025 through Winter 2026.

Figure A134: Interchange Optimization Benefit Estimate
Spring 2025 – Winter 2026



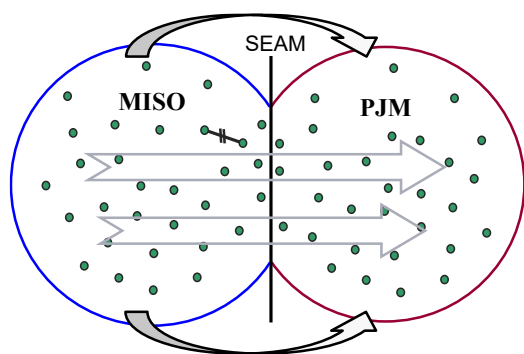
C. Interface Pricing and External Transactions

Each RTO posts interface prices at which it settles with physical schedulers seeking to buy and sell power with the neighboring RTO. Participants schedule flows between the RTOs to arbitrage differences between the two interface prices. Interface pricing is essential because:

- It solely facilitates efficient power flows between RTOs;
- Poor interface pricing can lead to significant uplift costs and other inefficiencies; and
- It is essential for CTS to maximize interface utilization.

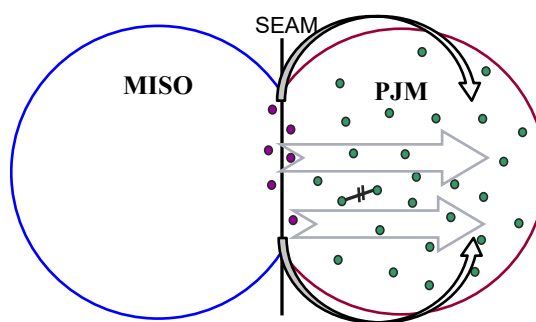
Establishing efficient interface prices would be simple without transmission congestion and losses—each RTO would post the interface price as the cost of the marginal resource on its system (the system marginal price, or “SMP”). Participants would then schedule from the lower-cost system to the higher-cost system until the SMPs equalize. However, congestion is pervasive, so the fundamental issue in interface pricing is estimating the congestion costs and benefits of imports and exports.

Like the LMP at all generation and load locations, the interface price includes: a) the SMP, b) a marginal loss component, and c) a congestion component. For generator locations, the source of the power is known, so market participants can accurately calculate congestion effects. In contrast, *the source of an import (or sink for an export) is not known*, so market participants must assume it to calculate the congestion effects. This assumed source or sink is the “*interface definition*”. If the interface definition reflects the actual source or sink of the power, the interface price will provide an efficient scheduling incentive and lower costs for both systems.



When power moves from one area to the other, generators ramp up throughout one area and ramp down throughout the other area, as shown in the figure on the left. These are the marginal units. This figure is consistent with MISO’s interface pricing before June 2017, which calculated flows for exports to PJM based on power sinking throughout PJM. This is accurate because PJM ramps down its marginal generators when it imports power.

Because both RTOs price congestion on M2M constraints, MISO and PJM had redundantly priced some congestion. To address this concern, PJM and MISO agreed to implement a “common interface” that assumes power sources and sinks at the border with MISO, as shown in the second figure on the right below. This “common interface” consists of 10 generator locations near the PJM seam: five points in MISO and five in PJM. This approach tends to exaggerate the flow effects of imports and exports on constraints near the seam because it underestimates the amount of power that loops outside the RTOs.

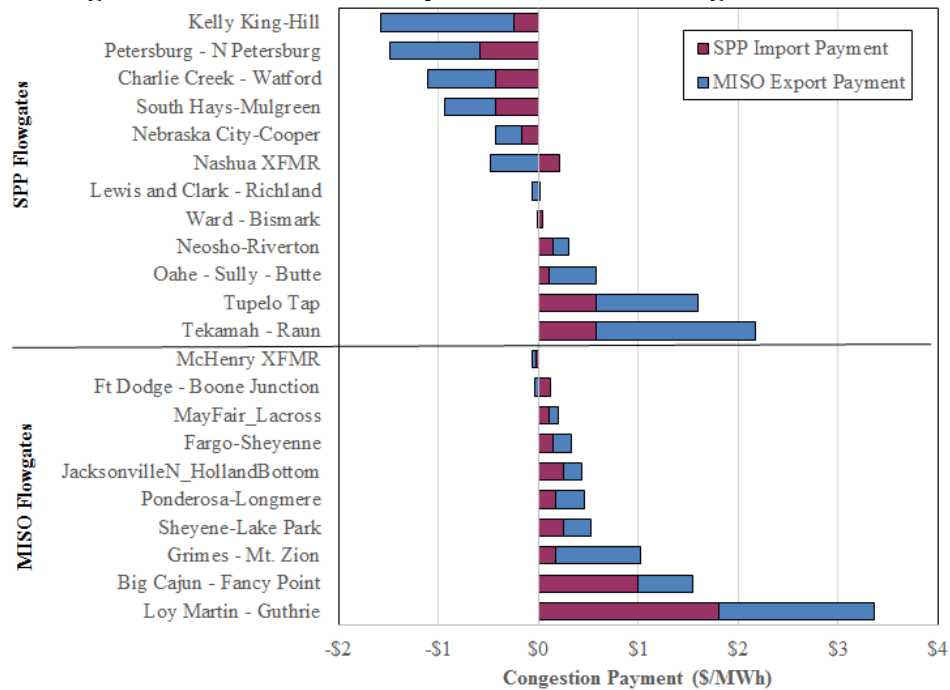


We identified the locations of MISO’s marginal generators and confirmed that they are distributed *throughout* MISO. Thus, we are concerned that the common interface definition sets inefficient interface prices. Our interface pricing studies show that, in aggregate, the common interface has led to larger average errors and greater volatility at the interface. These results indicate that this approach was a mistake. Fortunately, MISO uses this type of interface definition only at the PJM interface, whereas PJM uses it on all of its interfaces.

Figure A135: Constraint-Specific Interface Congestion Prices

Both MISO and SPP employ reasonable interface definitions to estimate how imports from and exports to the other area affect their transmission constraints. However, because both RTOs activate and model M2M constraints in their real-time markets, an unintended consequence is that both RTOs price congestion on those constraints. This causes SPP and MISO to “double pay” transactions for the congestion effects on M2M constraints.

To show how this occurs, we calculated the average interface pricing component for selected individual M2M constraints. These coordinated constraints had congestion values exceeding \$1 million between June 2018 and May 2019. Figure A135 shows the congestion component that SPP and MISO calculated for each constraint and separates MISO constraints from SPP constraints. The congestion payments are shown as the settlement of an export transaction from MISO to SPP. A negative value indicates that the participant would be charged the corresponding amount, whereas a positive value indicates that the participant would be paid for congestion relief.

Figure A135: Constraint-Specific Interface Congestion Prices

Although their interface definitions differ, the figure shows that both RTOs estimate very similar effects for each jointly managed constraint. As a result, congestion payments and charges are roughly double the efficient level. MRTTO payments alone are efficient because they reflect the marginal cost of managing the constraint.

Interface Pricing and External TLR Constraints

MISO activates M2M constraints from PJM or SPP in its real-time market. MISO also activates constraints in external areas when the external system operator calls a TLR. It is appropriate to reflect external constraints in MISO's real-time dispatch and internal LMPs. This allows MISO to respond to TLR relief requests as efficiently as possible. Although MISO must redispatch internal generation to respond to TLRs, it is not obligated to pay participants to schedule transactions that relieve constraints in external areas. In fact, MISO excludes the effects of real-time physical schedules from market flow, so it gets no credit for any relief that these external transactions provide.³⁴ Because MISO receives no credit for this relief and no reimbursement for the costs it incurs, it is inequitable for MISO's customers to bear these costs. Most of these costs take the form of balancing congestion uplifted to MISO load.

In addition to this inequity, these congestion payments motivate participants to schedule transactions inefficiently for three reasons. First, in most cases, the area where the constraint is located already fully compensates these beneficial transactions. For example, when IESO calls a TLR, it establishes an interface price (or congestion settlement) for a transaction over its interface with MISO that includes the transaction's effect on its own constraint. MISO's additional payment is redundant and inefficient.

³⁴ Transactions scheduled in the day-ahead market and curtailed via TLR on an external flowgate are paid for relieving the constraint even though this effect is excluded from MISO's market flow calculation.

Second, the TLR process assigns market flow obligations and curtails physical schedules so the owner can manage a given flowgate. Any flow reduction beyond these amounts decreases the monitoring area's need to reduce its own flows and can cause the transmission constraint in the monitoring area to become non-binding. MISO's current interface pricing compensates schedulers for inefficient additional relief at the expense of MISO customers.

Finally, MISO's shadow cost for external TLR constraints frequently and significantly overstates the monitoring system operator's true marginal cost of managing congestion on the constraint. As shown in Section V.F, this makes the congestion component of interface prices associated with TLR constraints highly distortionary and creates inefficient scheduling incentives.

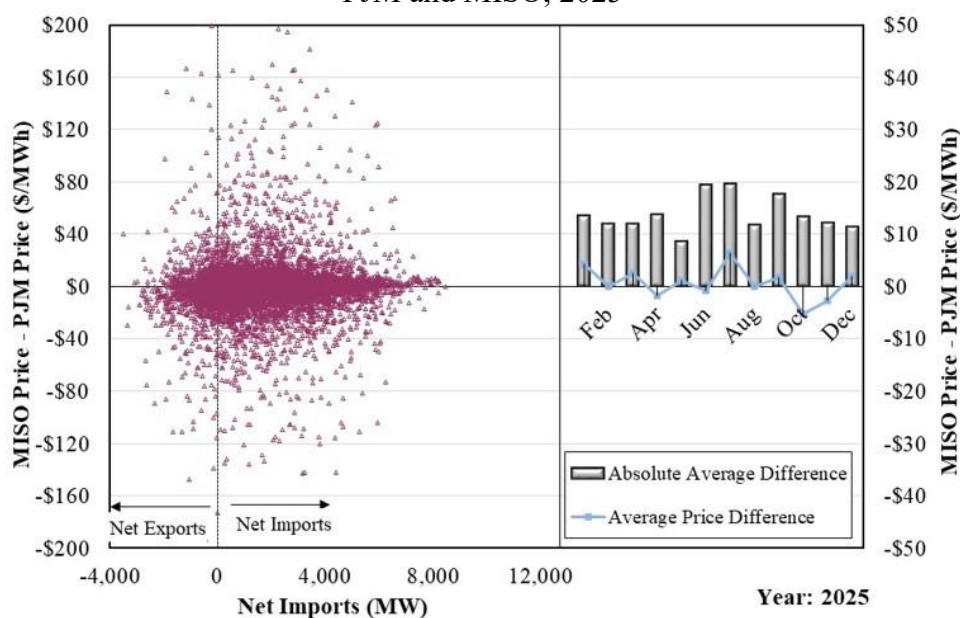
D. Price Convergence Between MISO and Adjacent Markets

Participants increase or decrease net imports to converge prices with adjacent markets. Because transaction scheduling occurs under future price uncertainty, perfect convergence is not expected. Transactions can start and stop at 15-minute intervals during an hour, and participants must schedule them 20 minutes in advance of the operating period.

Figure A136: Real-Time Prices and Interface Schedules

We present our analysis of these schedules in two figures, each with two panels. The left panel displays a scatter plot of real-time price differences and net imports during all unconstrained hours. Good market performance is characterized by net imports into MISO when its prices are higher than those in neighboring markets. The right panel of each figure shows the monthly average hourly real-time price difference between adjacent regions and the monthly average magnitude of the hourly price differences, measured as average absolute differences. In an efficient market, prices should converge when the interfaces between regions are not congested. Figure A136 shows these results for the MISO-PJM interface.

Figure A136: Real-Time Prices and Interface Schedules
PJM and MISO, 2025



VIII. COMPETITIVE ASSESSMENT AND MARKET POWER MITIGATION

This section evaluates the competitive structure and performance of MISO’s markets using various measures to identify market power and, more importantly, assess whether suppliers have exercised it. These assessments are particularly important in LMP markets because, although the market as a whole may normally be highly competitive, local market power associated with chronic or transitory transmission constraints can make these markets susceptible to its exercise.

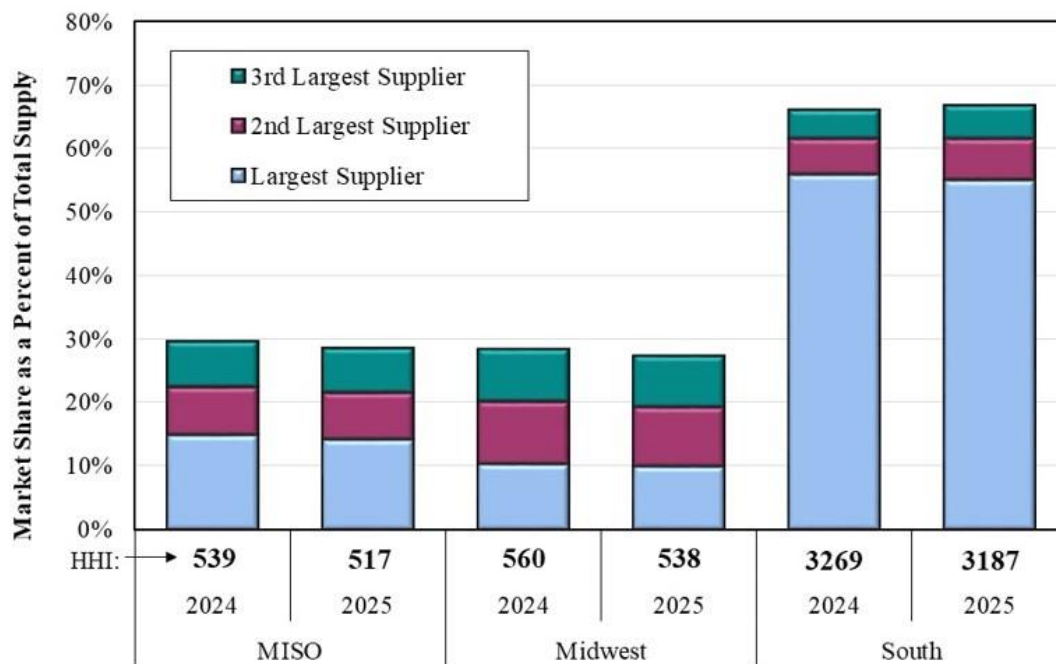
A. Structural Market Power Indicators

This subsection provides three structural analyses of the markets. The first examines the concentration of supply ownership in MISO as a whole and in each MISO region. The second and third analyses address how often suppliers in MISO are “pivotal” and needed to serve load reliably or resolve transmission congestion. In general, the two pivotal supplier analyses provide more accurate indications of market power in electricity markets than the market concentration analysis.

Figure A137: Market Shares and Market Concentration by Region

The first analysis measures market concentration using the Herfindahl-Hirschman Index (HHI). It calculates the HHI by summing the squares of each participant’s market share. Antitrust agencies characterize markets with an HHI less than 1000 as unconcentrated and those with an HHI greater than 1800 as highly concentrated. Figure A137 shows capacity-based market shares and HHIs for MISO and its subregions.

Figure A137: Market Shares and Market Concentration by Region
2024–2025

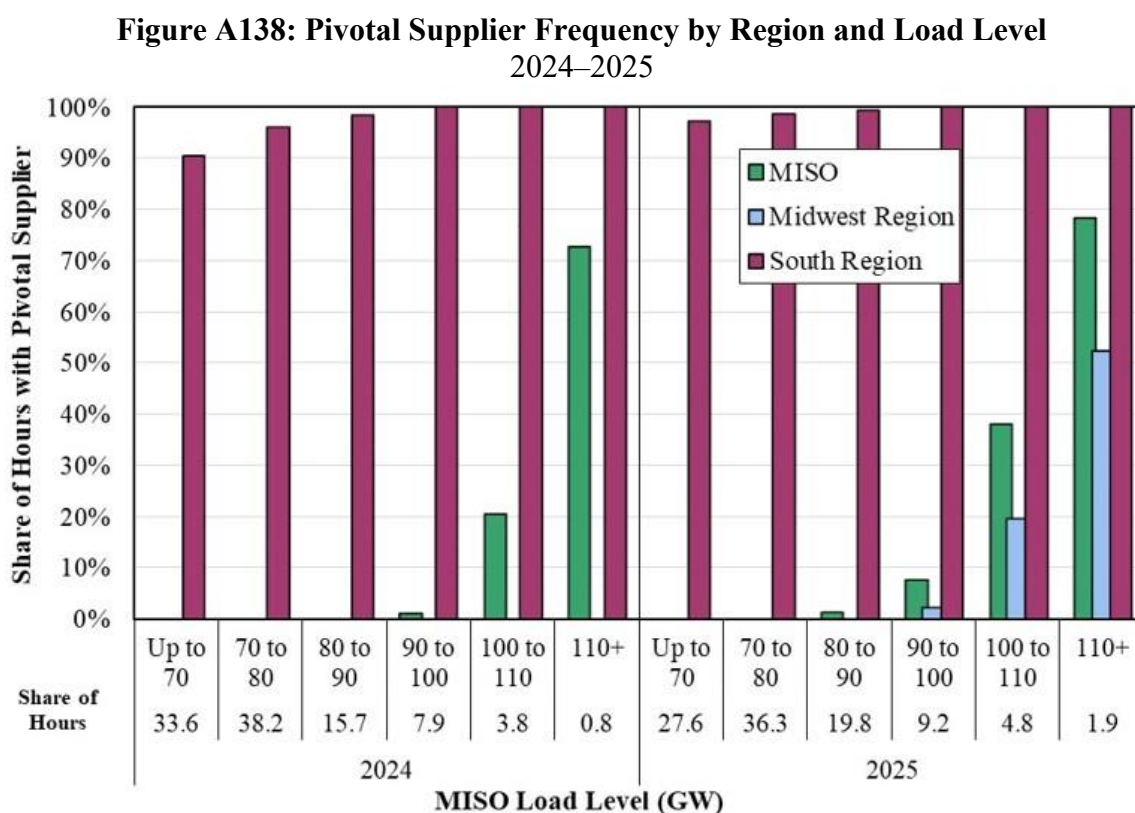


Market shares and the HHI are only general indicators of market concentration, not a definitive measure of market power. The most significant shortcoming of market shares and HHIs in identifying market power in electricity markets is that they generally do not account for demand or network constraints. In wholesale electricity markets, these factors profoundly affect competitiveness. Because market shares and the HHI do not recognize the physical characteristics of electricity that can cause a supplier to have market power under various conditions, these measures alone do not allow conclusive inferences regarding the overall competitiveness of electricity markets. The next two analyses more accurately reveal potential competitive concerns in the MISO markets.

Figure A138: Pivotal Supplier Frequency by Region and Load Level

The pivotal supplier metric is a better measure of potential market power. It considers supply, demand, and import capability into the market. A supplier is pivotal when some of its resources are needed to satisfy demand (i.e., it is a monopolist over some portion of the load).

Figure A138 summarizes this analysis by showing the percentage of hours with a pivotal supplier by region and load level. Prices are most sensitive to withholding under high-load conditions, making it more likely that a supplier could profitably exercise market power in those hours. The percentages below the horizontal axis indicate the share of hours in each load level.



While the regional pivotal supplier analysis is useful for evaluating a market’s competitiveness, identifying local market power requires a more detailed analysis of specific transmission constraints that can isolate locations on the transmission grid. By specifying when a supplier is

pivotal relative to a particular transmission constraint, such analyses indicate local market power more precisely than either the HHI or RDI.

A supplier is pivotal on a constraint when it has enough resources to load the constraint so much that all other suppliers combined cannot relieve it. This often occurs on lower-voltage constraints because the resources that most affect flow are nearest the constraint. If the same supplier owns all or a substantial share of these resources, it is likely pivotal in managing congestion on the constraint. As a result, it can potentially manipulate congestion and control prices.

MISO defines two types of constrained areas for market power mitigation: Broad Constrained Areas (BCAs) and Narrow Constrained Areas (NCAs), including *Dynamic* Narrow Constrained Areas. The electrical properties of the transmission network that can lead to local market power determine the definitions of BCAs and NCAs. NCAs are chronically constrained areas where one or more suppliers are frequently pivotal. Therefore, they can be defined in advance and are subject to tighter market power mitigation thresholds than BCAs. MISO Midwest has three NCAs (the Minnesota NCA, the WUMS NCA, and the North WUMS NCA), and MISO South has two (WOTAB and Amite South NCAs).³⁵

Market power associated with BCA constraints can also be significant. When a non-NCA transmission constraint binds, a BCA includes all resources that significantly affect power flows on the constraint. BCA constraints are not chronic like NCA constraints. However, they can raise competitive concerns. Because of the large number of potential constraints and because transmission topology can change significantly during outages, it is neither feasible nor desirable to define all possible BCAs in advance.

Figure A139 to Figure A140: Pivotal Suppliers on Transmission Constraints

The next two figures evaluate potential local market power by showing how often suppliers are pivotal on individual NCA and BCA constraints. Figure A139 shows the percentage of all market intervals in each season during which at least one supplier was pivotal for each type of constraint. Figure A140 shows the percentage of intervals with active constraints in each season during which at least one supplier was pivotal. For this analysis, the WUMS and North WUMS NCAs in the Midwest region are combined.

³⁵ Based on the results of the NCA threshold calculation specified in Tariff Section 64.1.2.d, the conduct-impact thresholds that applied to the NCAs for the second half of 2025 ranged from \$22.05 per MWh in Minnesota to \$100.00 per MWh in Amite South and WOTAB. The North WUMS and WUMS thresholds were \$27.97 and \$43.43, respectively. The NCA thresholds are updated annually on June 1 and published on the MISO website.

Figure A139: Percentage of Intervals with at Least One Pivotal Supplier
2025

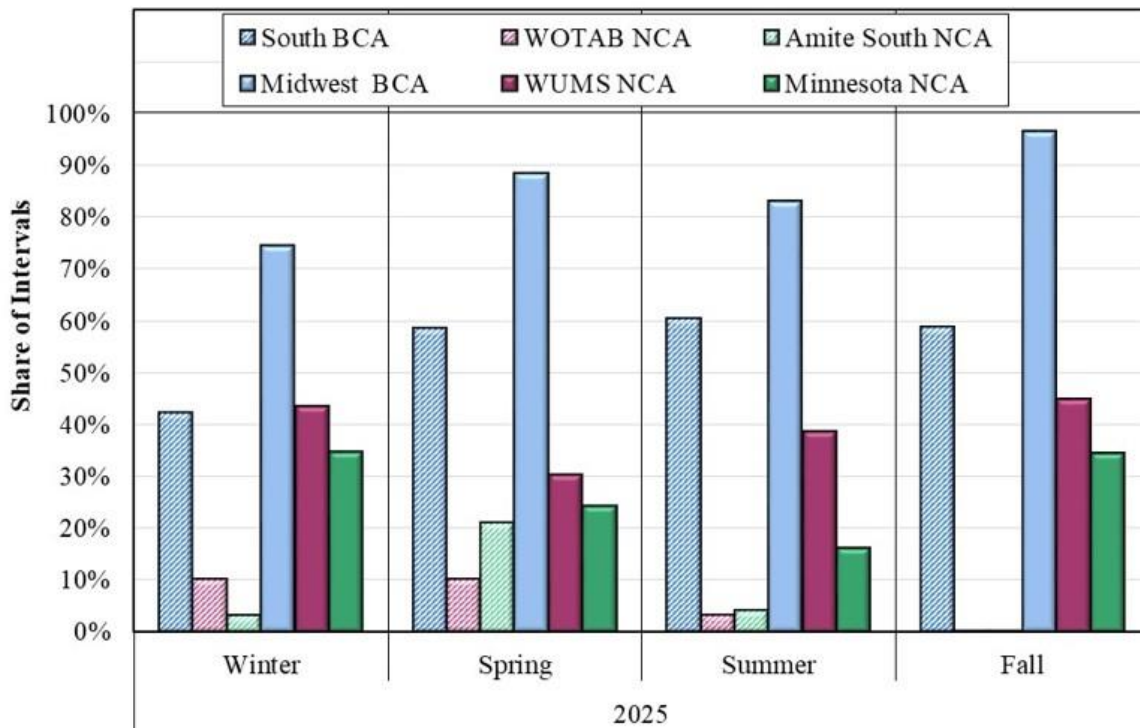
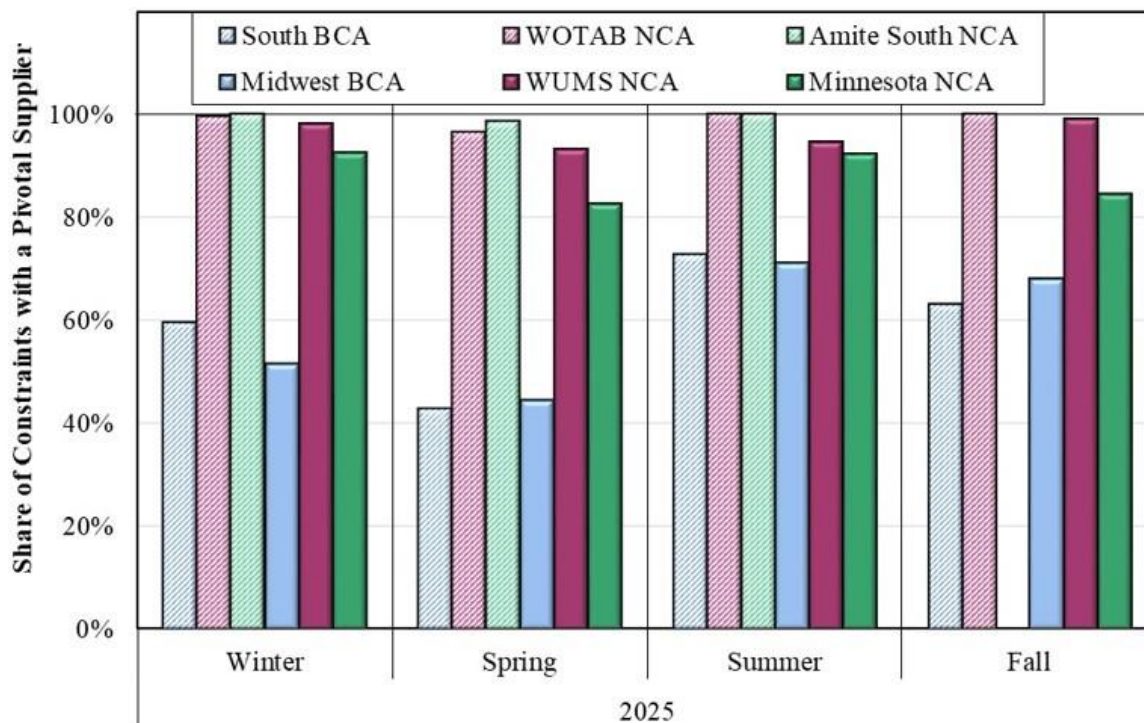


Figure A140: Percentage of Active Constraints with a Pivotal Supplier
2025



Participant Conduct – Price-Cost Mark-Up

The structural analyses in the prior subsection indicate the likely presence of local market power associated with transmission constraints in the MISO market area. In the next three subsections, we analyze participant conduct to determine whether it was consistent with competitive behavior or indicated attempts to exercise market power. We test for two types of conduct associated with the exercise of market power: economic withholding and physical withholding. Economic withholding occurs when a participant offers its resource at a price substantially above a competitive offer (i.e., above its marginal cost) to raise market clearing prices or increase RSG payments. Physical withholding occurs when an economic unit is unavailable to produce some or all of its output. Participants generally achieve such withholding by claiming an outage or derating a resource, although they can manipulate other physical parameters to achieve a similar outcome.

The price-cost mark-up is one metric for evaluating the market's competitive performance. It estimates the "mark-up" of real-time market prices over suppliers' competitive costs by comparing a simulated SMP under two assumptions: (1) suppliers offer at prices equal to their reference levels, and (2) suppliers submit their actual offers. We then calculate the annual load-weighted average estimated SMP under each scenario. The percentage difference between the estimated SMPs is the mark-up. This analysis does not account for physical restrictions on units, transmission constraints, or potential changes in resource commitments, all of which would require re-running market software.

The price-cost mark-up metric is useful for evaluating the market's competitive performance. A competitive market should produce a small mark-up because suppliers should have incentives to offer at their marginal costs. Under competitive conditions, offers above marginal cost could prevent resources from clearing the market and reduce revenue contributions that cover fixed costs. Many factors can cause reference levels to vary slightly from suppliers' true marginal costs. Nonetheless, we found an average system marginal price-cost mark-up of -1 percent in 2025, ranging monthly from a high of 2.7 percent to a low of -4.4 percent.

B. Participant Conduct – Potential Economic Withholding

Analyzing economic withholding requires comparing actual offers to competitive offers. Suppliers that lack market power maximize profits by offering resources at marginal cost. A generator's marginal cost is its incremental cost of producing additional output. It may include inter-temporal opportunity costs, outage risk, fuel, variable operations and maintenance (VOM), and other costs attributable to the incremental output. For most fossil fuel-fired resources, variable production costs, which primarily consist of fuel and VOM costs, closely approximate marginal costs.

However, marginal costs can exceed variable production costs. For instance, operating at high output levels or for long periods without routine maintenance can increase a unit's risk of outage. Additionally, generating resources with energy limitations, such as hydroelectric units or fossil fuel-fired units with output restrictions because of environmental considerations, may forego future revenues to produce in the current period. These units can incur inter-temporal opportunity costs that cause their marginal cost to exceed variable production cost.

Establishing a competitive benchmark, or “reference level,” for each offer parameter of each unit is a key component of identifying economic withholding. MISO’s market power mitigation measures include several methods for calculating a resource’s reference levels.³⁶ We use these reference levels in the analyses below and to apply mitigation. Comparing offers with competitive benchmarks—reference prices plus the applicable threshold specified in the Tariff—constitutes the “conduct test,” the first prerequisite for imposing market power mitigation. The second prerequisite is the “impact test,” which requires the identified conduct to significantly affect market prices or guarantee payments.

To identify potential economic withholding, we calculate an “output gap” metric from a resource’s startup, no-load, and incremental energy offer parameters. The output gap is the difference between a unit’s economic output level at the prevailing clearing price, based on the unit’s reference levels, and the amount the unit actually produces. The output gap thus quantifies the generation that a supplier may withhold from the market by submitting offers above competitive levels. Therefore, the output gap for any unit generally equals:

$Q_i^{\text{econ}} - Q_i^{\text{prod}}$ when greater than zero, where:

Q_i^{econ} = Economic level of output for unit i ; and
 Q_i^{prod} = Actual production of unit i .

To estimate Q_i^{econ} , the economic level of output for a particular unit, we examine all parts of the unit’s three-part reference level: startup cost reference, no-load cost reference, and incremental energy cost reference. These costs jointly determine whether the unit would have been economic at the clearing price for at least its minimum run time.

We use a three-stage process to determine a unit’s economic output level in a particular hour. First, we examine whether the unit would have been economic to commit on that day if it had offered our estimate of its marginal costs. Specifically, we examine whether the unit would have recovered its actual startup, no-load, and incremental costs by running at the dispatch point dictated by the prevailing LMP, subject to the unit’s economic minimum and maximum, for its minimum run time. Second, if a unit was economic to commit, we identify the set of contiguous hours when it was economic to dispatch.

Finally, we determine the economic level of incremental output in hours when the unit was economic to run. When the unit was not economic to commit or dispatch, we considered the economic level of output to be zero. To reflect the timeframe when market participants typically make such commitment decisions in practice, we based this assessment on day-ahead market outcomes for non-quick-start units and on real-time market outcomes for quick-start units.

Our benchmarks for units’ marginal costs are imperfect, particularly during periods of volatile fuel prices. Therefore, we add a threshold to the resources’ reference level to determine Q_i^{econ} . This ensures that we identify only significant departures from competitive conduct. These

³⁶ See Module D, Section 62.a, which states: “These market power Mitigation Measures are intended to provide the means for the Transmission Provider to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the Markets and Services administered by the Transmission Provider, while avoiding unnecessary interference with competitive price signals.”

thresholds are based on those defined in the Tariff for BCAs and NCAs and are described in more detail below.

Q_i^{prod} is the unit's actual observed production. The difference between Q_i^{econ} and Q_i^{prod} shows how much the unit fell short of its economic production level. However, some units are dispatched below their three-part offers. This indicates transmission constraints, reserve considerations, or other changes in market conditions between unit commitment and real time. Therefore, we adjust Q_i^{prod} upward to reflect three-part offers that would have made a unit economic to run, even if the unit was not fully dispatched. Hence, this report uses the following output gap formula:

$Q_i^{\text{econ}} - \max(Q_i^{\text{prod}}, Q_i^{\text{offer}})$ when greater than zero, where:

$Q_i^{\text{offer}} =$ offer output level of i .

By using the greater of actual production or the output level offered at the clearing price, we exclude infeasible energy that is due to ramp limitations from the output gap.

Figure A141: Economic Withholding – Output Gap Analysis

Figure A141 shows monthly average output gap levels in the real-time market for 2024 and 2025. The output gap in the chart and inset table includes two types of units:

- (1) online and quick-start units available in real time, and
- (2) offline units that would have been economic to commit.

The data show the output gap using each area's mitigation threshold ("high threshold") and one-half of that threshold ("low threshold"). MISO tests resources in NCAs at the comparatively tighter NCA conduct thresholds and tests resources outside NCAs at BCA conduct thresholds.

The high threshold for resources in BCAs is the lower of \$100 per MWh above the reference or 300 percent of the reference. Within NCAs, the high thresholds effective beginning on June 1, 5 were \$43.43 per MWh for resources in the WUMS NCA, \$37.97 for those in the North WUMS NCA, \$22.05 for those in the Minnesota NCA, and \$100.00 for both the WOTAB and Amite South NCAs. The low threshold is 50 percent of the applicable high threshold for a given resource. For example, for a resource in Amite South, the low threshold would be \$50.00 per MWh, or 50 percent of \$100.00.

To include a resource's unscheduled output in the output gap, its offered commitment cost per MWh or incremental energy offer must exceed the resource's reference plus the applicable threshold. The lower threshold indicates potential economic withholding of output offered at a price significantly above its reference yet within the mitigation threshold.

Figure A141: Economic Withholding – Output Gap Analysis
2024–2025

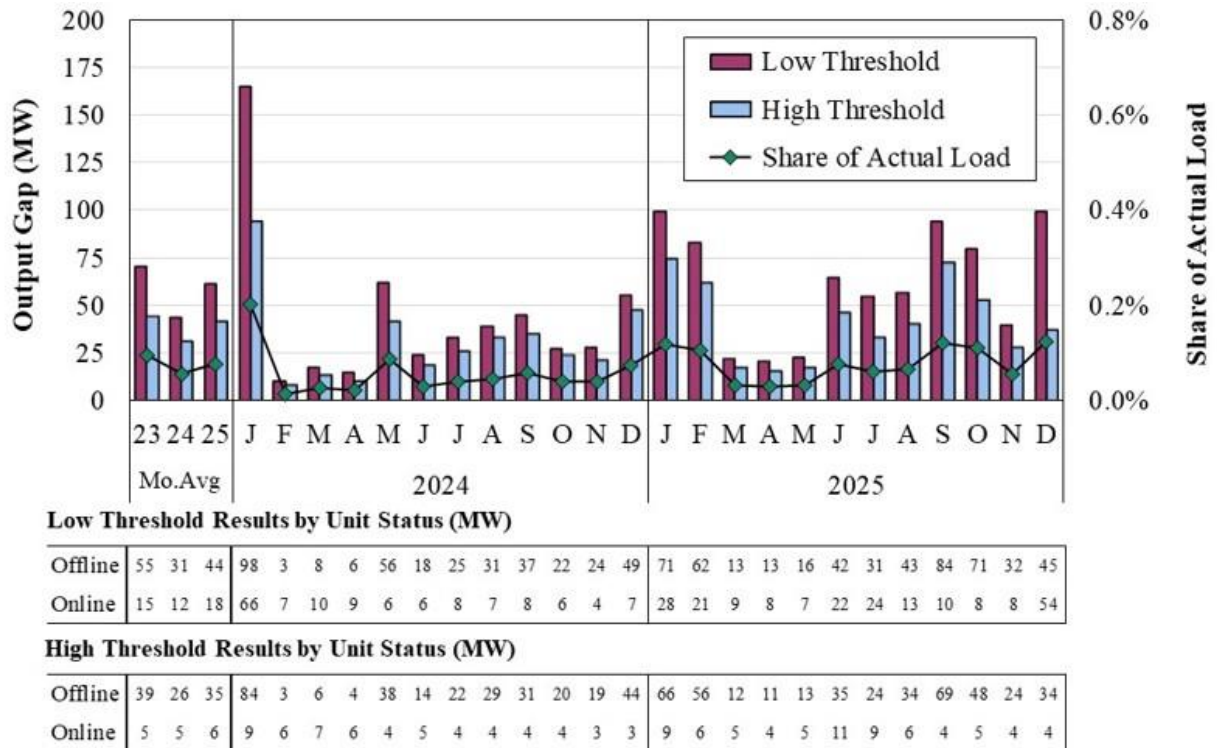


Figure A142 to Figure A145: Real-Time Average Output Gap and Load

Any measure of potential withholding inevitably includes some justified quantities. Therefore, we evaluate not only the absolute level of the output gap but also how it varies with factors that can give a supplier market power. This approach lets us test whether a participant's conduct is consistent with attempts to exercise market power.

The most important factors in this analysis are participant size and load level. Larger suppliers generally are more likely to be pivotal and tend to have greater incentives to increase prices than smaller suppliers. Load level is important because price sensitivity to withholding usually increases with load, particularly at the highest levels. This pattern occurs in part because rivals' least expensive resources are more fully utilized to serve load under these conditions, leaving only the highest-cost resources to respond to withholding.

The pivotal supplier analyses earlier in this section showed the effect of load on potential market power. The next four figures show the output gap in each region by load level and unit type (online and offline). They also show the two largest suppliers in each region separately from all other suppliers and the average output gap at the high and low mitigation thresholds defined above.

Figure A142: Real-Time Average Output Gap and Load
Central Region, 2025

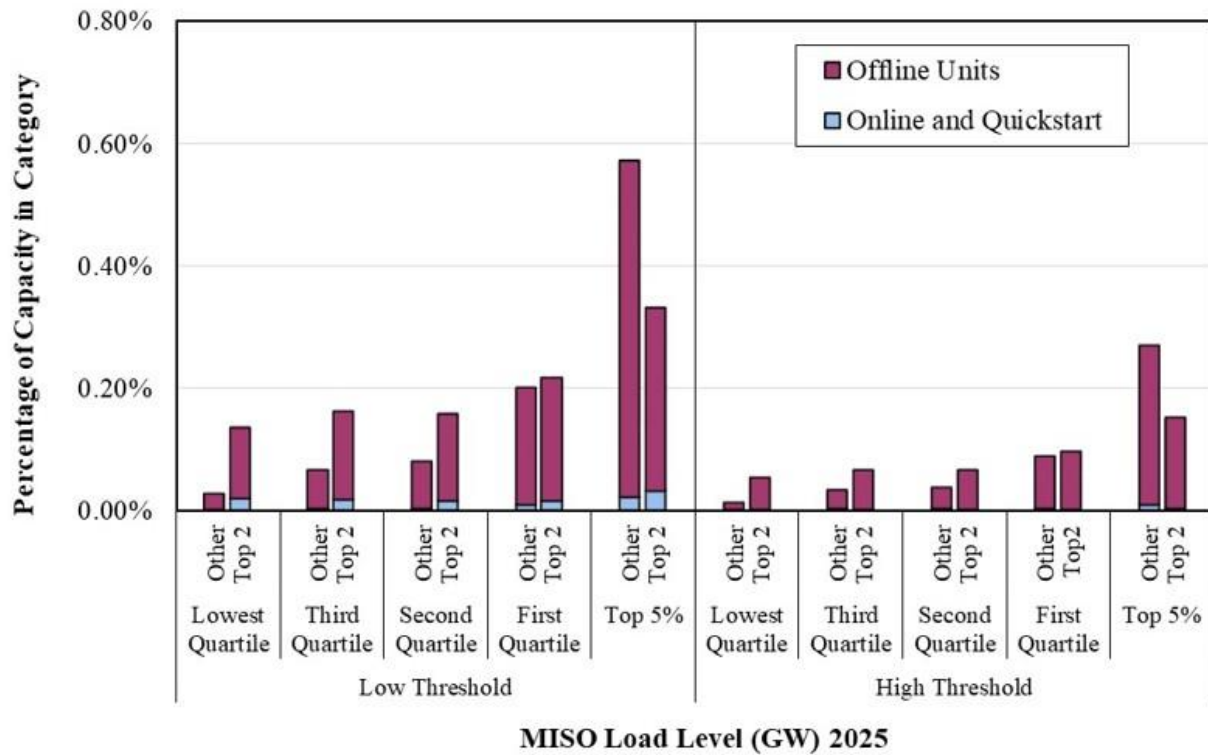


Figure A143: Real-Time Average Output Gap and Load
MISO South, 2025

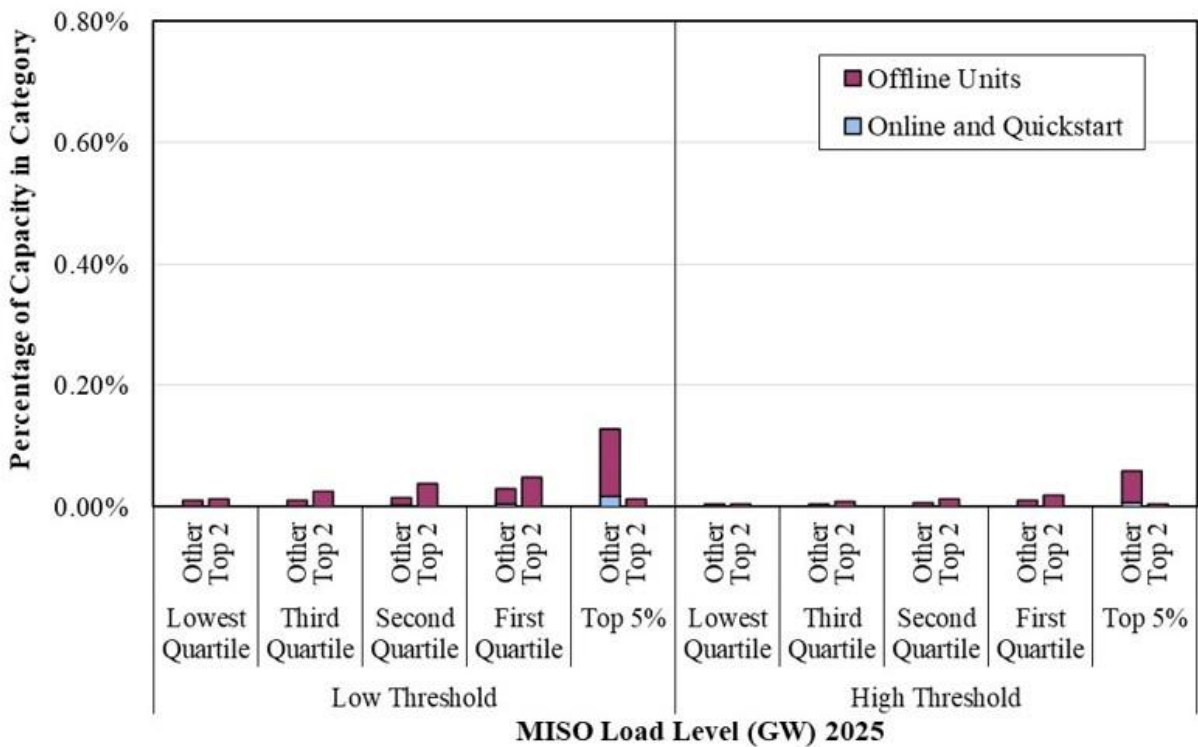


Figure A144: Real-Time Average Output Gap and Load
North Region, 2025

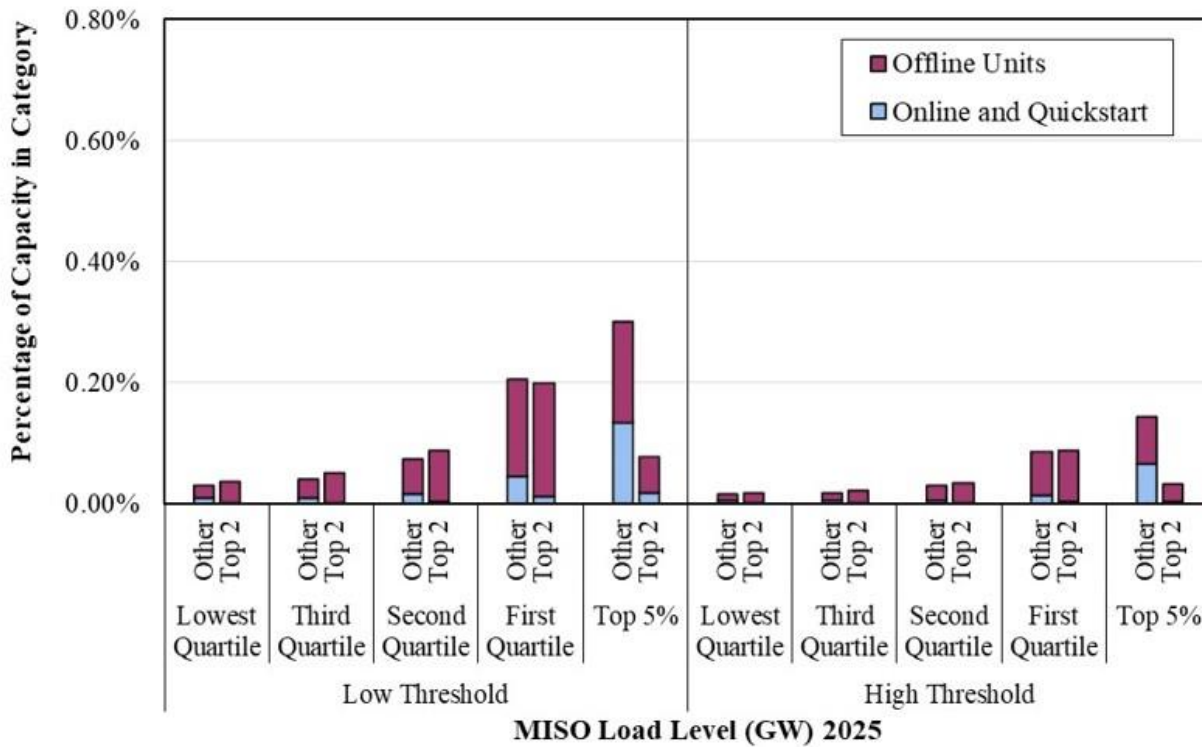
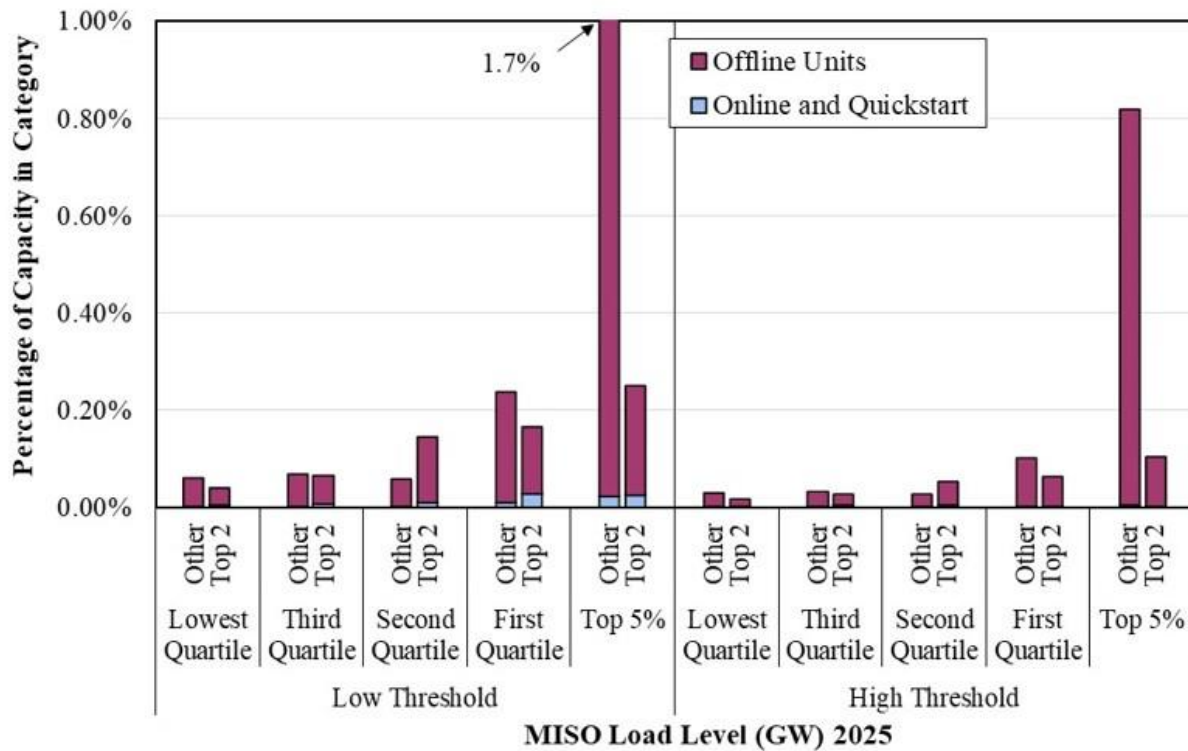


Figure A145: Real-Time Average Output Gap and Load
WUMS Area, 2025



C. Market Power Mitigation

In this next subsection, we examine the market power mitigation measures imposed in 2025. When the set of Tariff-specified criteria are met, a mitigated unit's offer price is capped at its reference level, which is a benchmark designed to reflect a competitive offer. MISO only imposes mitigation measures when suppliers' conduct exceeds well-defined conduct thresholds and when the effects of that conduct on market outcomes exceed well-defined market impact thresholds. By applying these conduct and impact tests, the mitigation measures are designed to allow prices to rise efficiently while effectively mitigating abuses of market power.

Participants are subject to potential mitigation when binding transmission constraints result in local market power. The mitigation thresholds differ for two types of constrained areas: BCAs and NCAs. Market power concerns are greater in chronically constrained NCAs, where a supplier is typically pivotal. Therefore, the conduct and impact thresholds for NCAs, which depend on the frequency of congestion, are generally lower than those for BCAs.

Figure A146: Day-Ahead and Real-Time Energy Offer Mitigation by Month

Figure A146 shows the frequency and quantity of mitigation in the day-ahead and real-time energy markets by month. Mitigation generally occurs more frequently in the real-time market because virtual participants and the wider range of commitment and dispatch options in the day-ahead market provide liquidity. As a result, the day-ahead market is much less vulnerable to withholding and market power.

**Figure A146: Day-Ahead and Real-Time Energy Offer Mitigation by Month
2025**

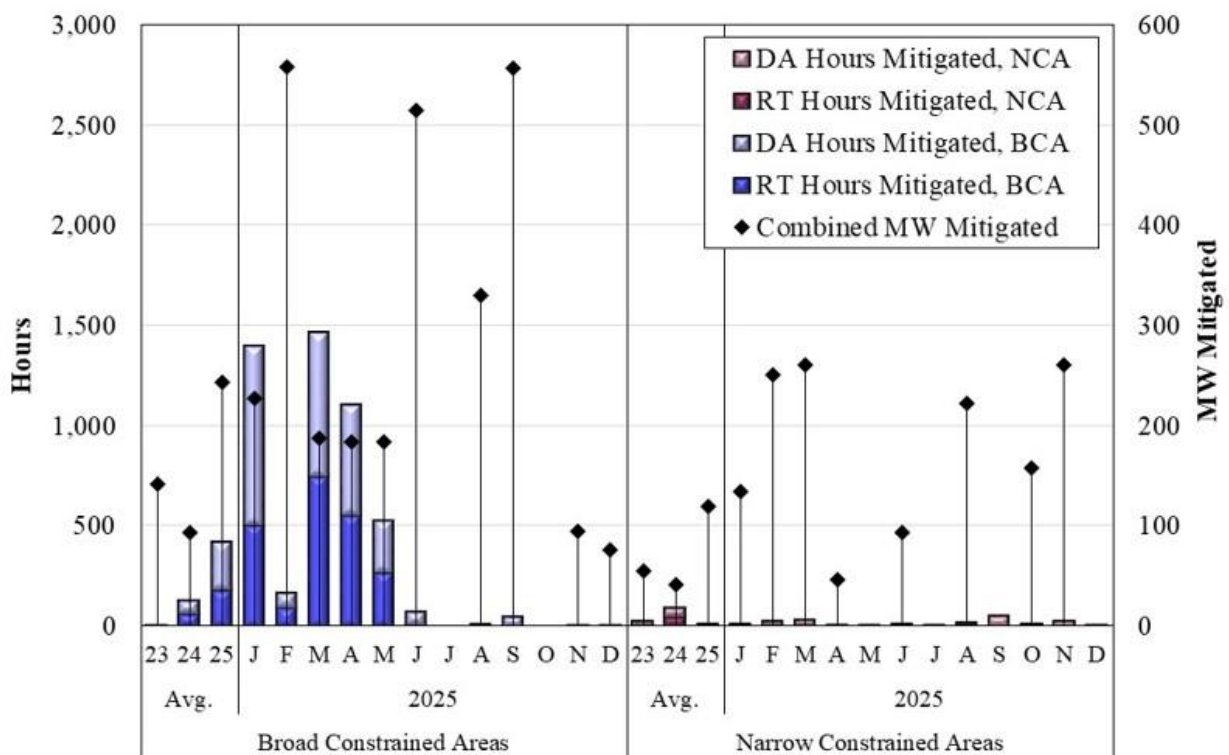
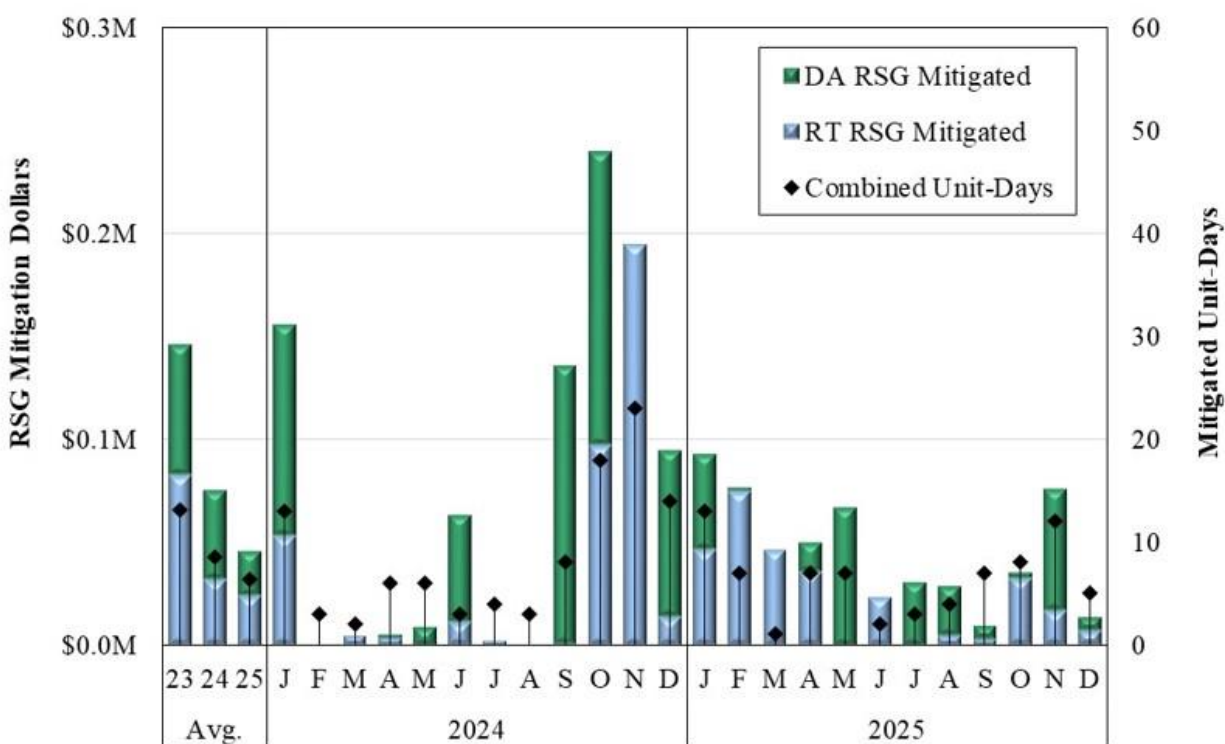


Figure A147: Day-Ahead and Real-Time RSG Mitigation by Month

Participants can exercise market power by raising their offers when their units must be committed to resolve a constraint or satisfy a local reliability requirement. This can compel MISO to make much higher RSG payments. MISO's mitigation measures address this conduct and are triggered when: (1) the unit is committed for a constraint or a local reliability issue; and (2) the unit's offer exceeds the conduct threshold, which is the greater of \$25 or a 25 percent increase in production costs. Figure A147 shows the frequency and amount of RSG payment mitigation in 2024 and 2025, and the average amounts for the last three years.

Figure A147: Day-Ahead and Real-Time RSG Mitigation by Month
2024–2025



D. Evaluation of RSG Conduct and Mitigation Rules

We routinely evaluate the effectiveness of the mitigation measures in addressing whether potential market power has been exercised to affect energy prices, ancillary services prices, or RSG payments. In this subsection we evaluate RSG-associated conduct.

Figure A148 to Figure A150: Real-Time RSG Payments by Conduct

We evaluate conduct associated with RSG payments in the following figures, separating the payments associated with resources' reference levels and the payments associated with the portions of resources' bid parameters (e.g., economic and physical parameters) that exceeded their reference levels. The figures show results separately for units committed for market capacity needs, congestion management, VLR requirements, and regional capacity needs (i.e.,

the RDT). The “Mitigated” category includes day-ahead and real-time amounts. Figure A148 shows all of MISO, while Figures A149 and A150 distinguish between the Midwest and South.

Figure A148: Real-Time RSG Payments by Conduct
By Commitment Reason, 2025

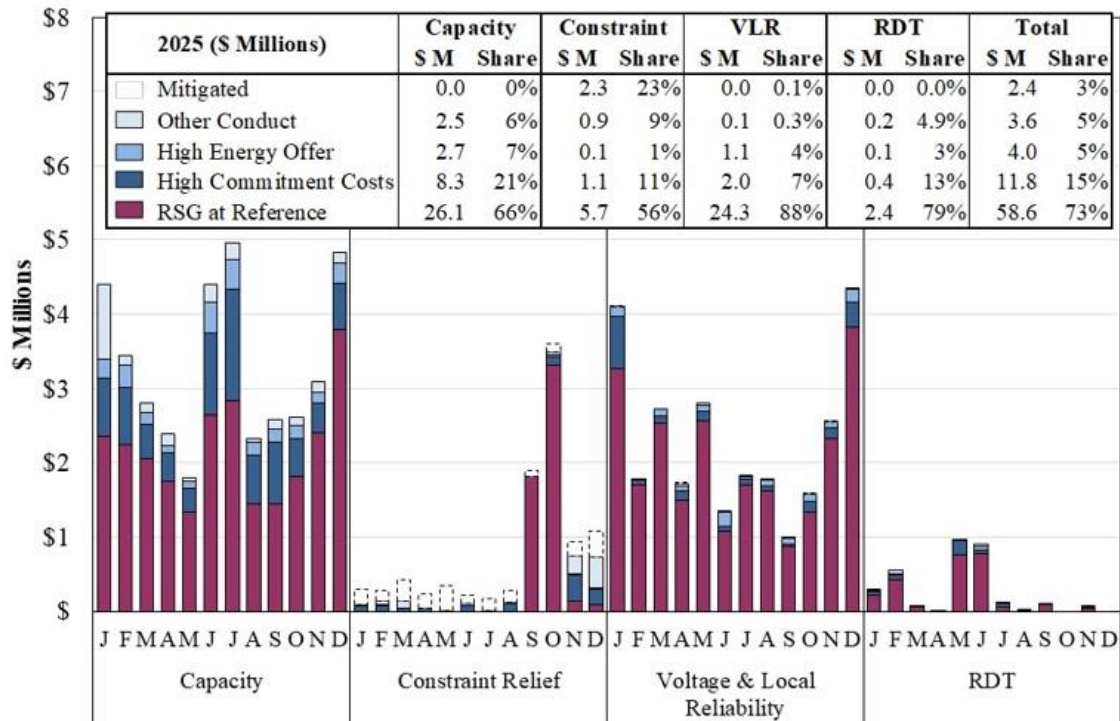


Figure A149: Real-Time RSG Payments by Conduct
Midwest Region, by Commitment Reason, 2025

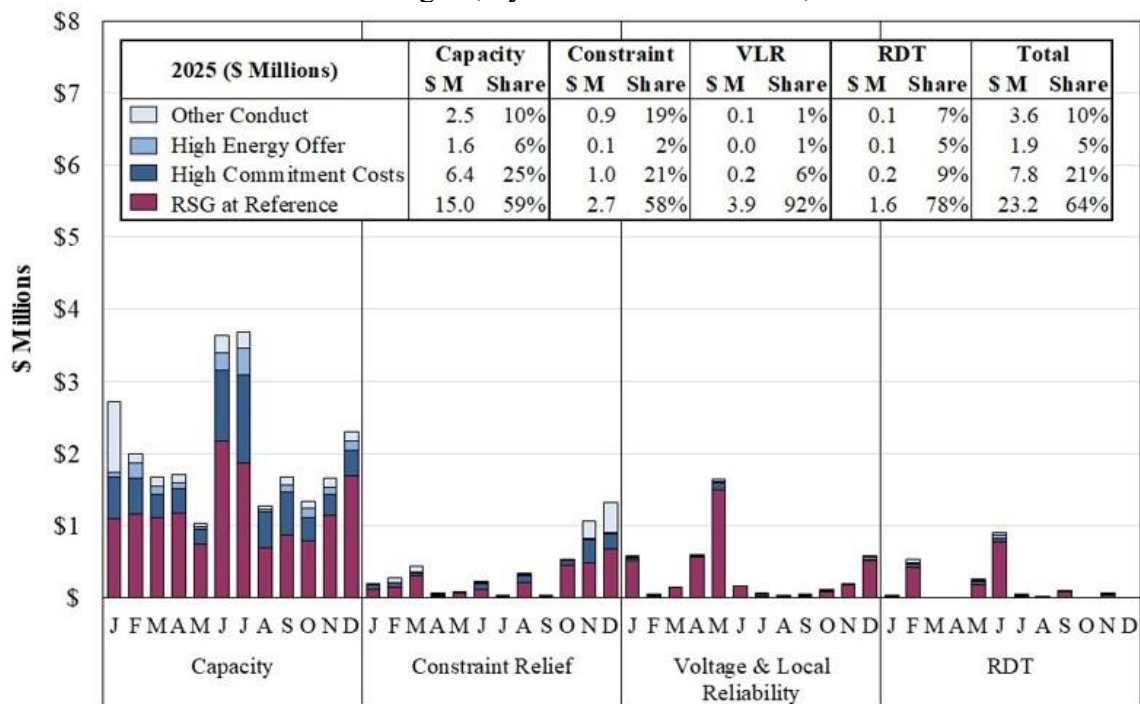
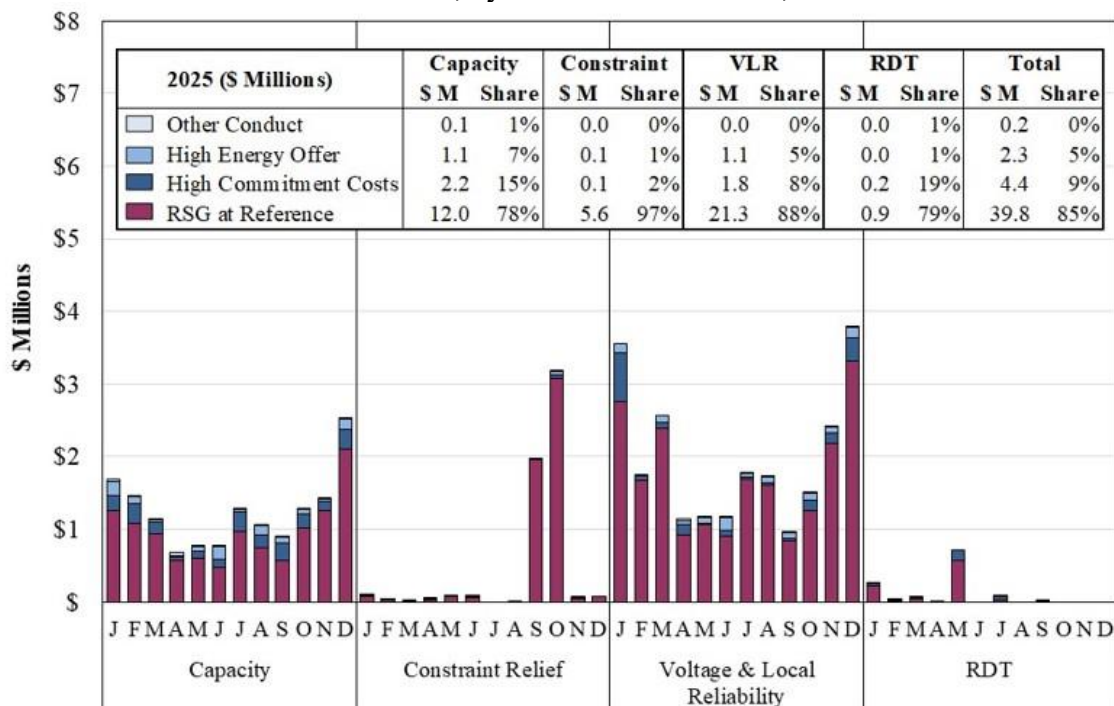


Figure A150: Real-Time RSG Payments by Conduct
MISO South, by Commitment Reason, 2025



Prior to June 2015, the RSG mitigation measures included conduct tests for each bid parameter individually and used a \$50 per MW impact threshold. In contrast, the voltage and local reliability (VLR) mitigation framework uses a conduct test based on a resource's aggregate as-offered production cost. This method recognizes the joint impact of all of a resource's offer parameters. When units committed for VLR require an RSG payment, each dollar of increased production cost translates to an additional dollar of RSG. Hence, the conduct test also serves as an impact test.

In late June 2015, FERC approved a \$25 or 25 percent conduct test for constraint commitments based on the VLR mitigation framework and eliminated the impact test. In August 2018, FERC approved MISO's mitigation authority for resources committed for the RDT in MISO South, using the same mitigation measures that apply to resources committed for transmission congestion. These changes improved the effectiveness of the RSG mitigation measures.

E. Participant Conduct – Ancillary Services Offers

In this subsection, we review the conduct of market participants in the ancillary services markets by summarizing the offer prices and quantities for spinning reserves and regulation.

Figure A151 to Figure A153: Ancillary Services Market Offers

Figure A151 to Figure A153 evaluate the competitiveness of ancillary services offers. These figures show the monthly average quantities of regulation and spinning reserve offered at prices ranging from \$10 to \$50 per MWh above reference levels and the share of total capacity that those quantities represent.

Figure A151 shows offers for all of MISO, while the next two figures show offers separately for MISO South and the Midwest. As for energy, ancillary services reference levels are resource-specific estimates of the competitive offer level for the service, equal to the marginal costs of supplying the services. We exclude supplemental (contingency reserves) from this figure because participants almost never offer this product at more than \$10 per MWh above reference levels.

Figure A151: Ancillary Services Market Offers
2024–2025

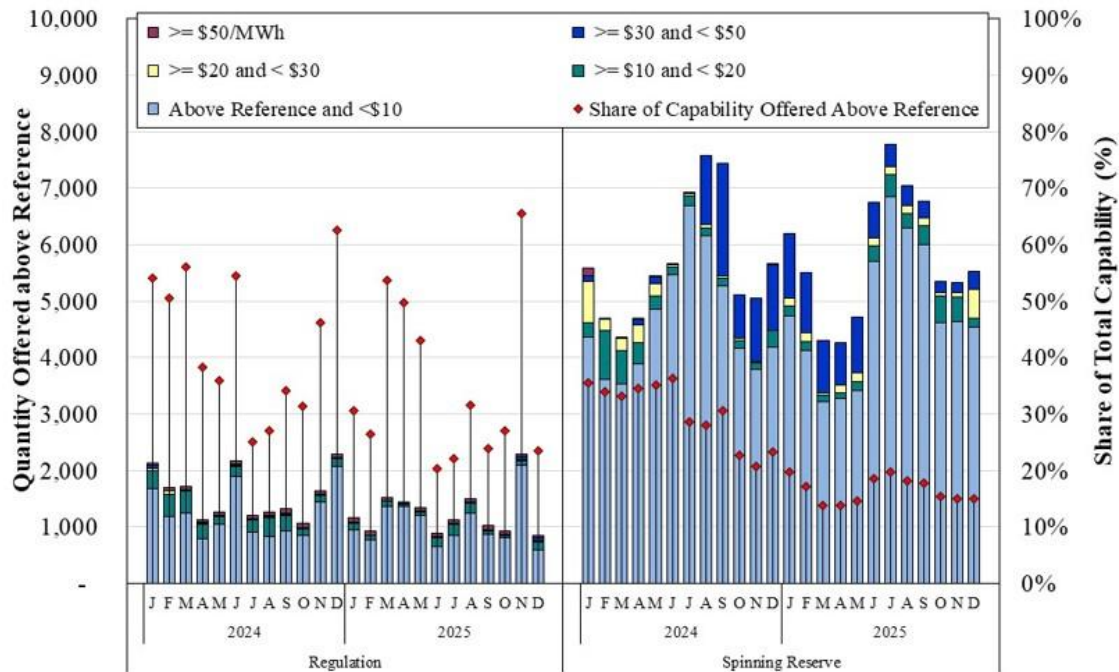


Figure A152: Ancillary Services Market Offers
Midwest Region, 2024–2025

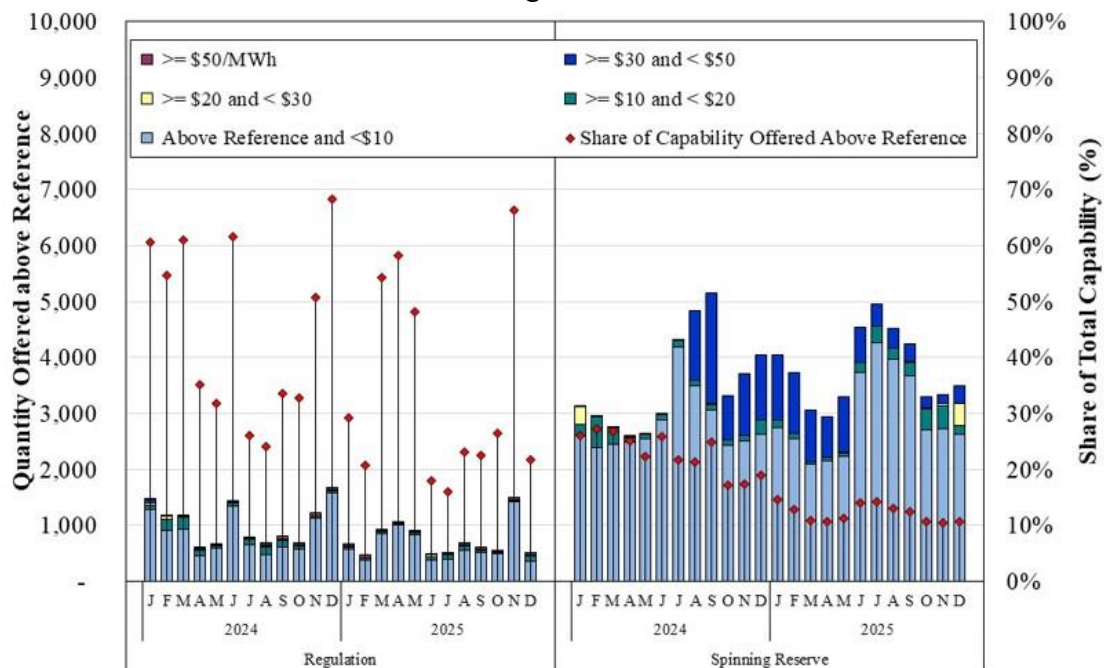
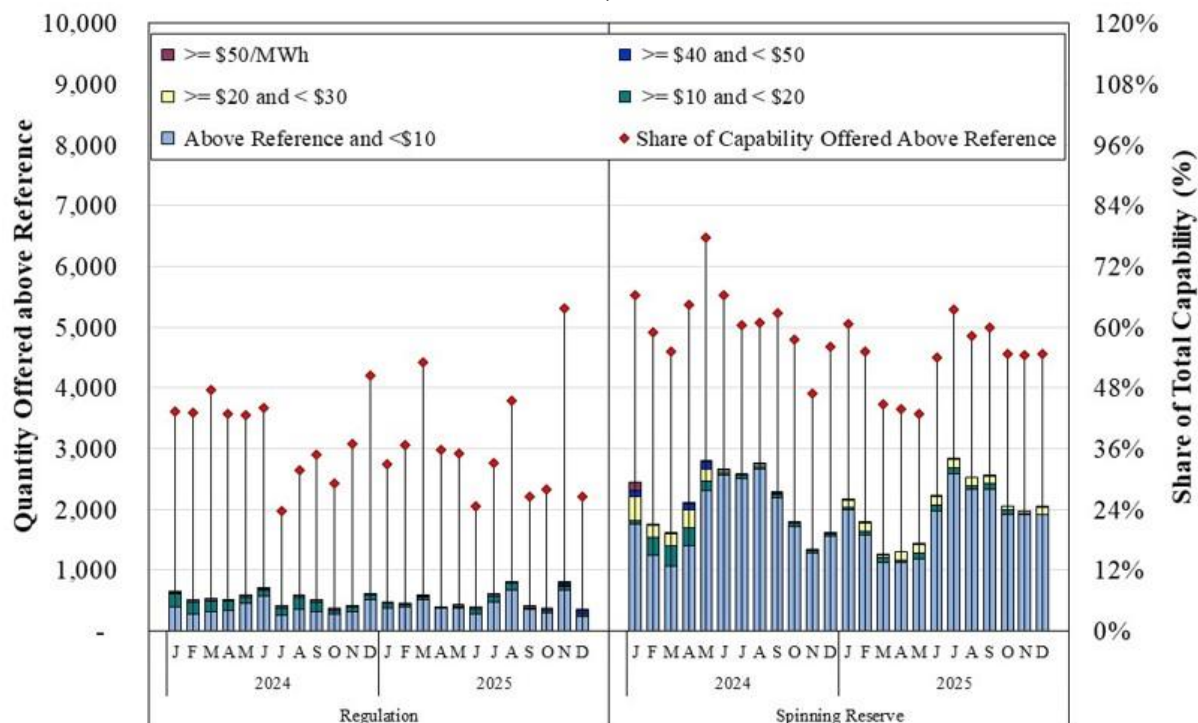


Figure A153: Ancillary Services Market Offers
MISO South, 2024–2025



F. Participant Conduct – Physical Withholding

The previous subsections analyzed offer patterns to identify potential economic withholding. By contrast, physical withholding occurs when a unit that is economic at the prevailing market price makes all or a portion of its output unavailable by offering restricted physical parameters or declaring other conditions. For instance, a supplier may physically withhold by unjustifiably claiming an outage or derating its resource (lowering the economic maximum parameter). Although we analyze broad patterns of outages and deratings for this report, we also monitor for potential physical withholding on a day-to-day basis and audit outages and deratings that have substantial effects on market outcomes.

Figure A154 to Figure A156: Real-Time Deratings and Forced Outages

The following three figures show, by region, the average share of capacity unavailable to the market in 2025 because of forced outages and deratings. As with the output gap analysis, this conduct may be justifiable or may reflect the exercise of market power. Therefore, we evaluate the conduct by load level and participant size to detect patterns consistent with withholding. Attempts to withhold would likely occur more often at high load levels, when prices are most sensitive to withholding. We also focus on short-term outages and deratings lasting fewer than seven days because long-term forced outages are less likely to be profitable withholding strategies. A supplier that takes a long-term forced outage on a unit that would be economic during the outage would likely forego greater potential profits during hours when it does not have market power than it could earn during hours when it does.

Figure A154: Real-Time Deratings and Forced Outages
Central Region, 2025

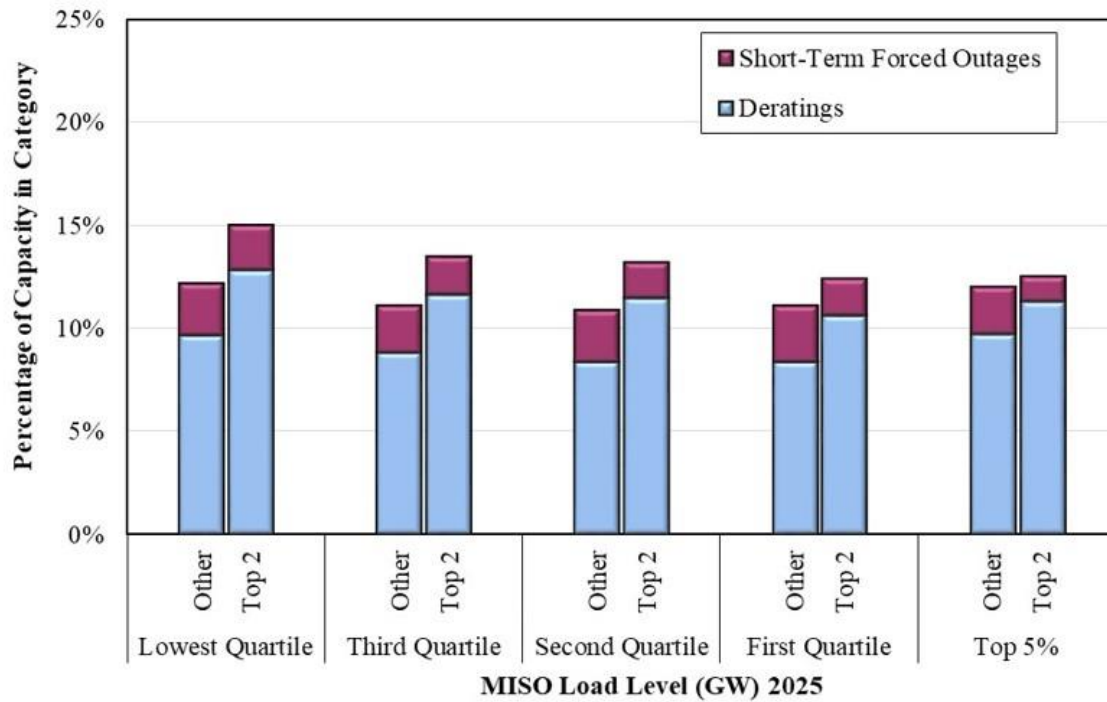


Figure A155: Real-Time Deratings and Forced Outages
MISO South, 2025

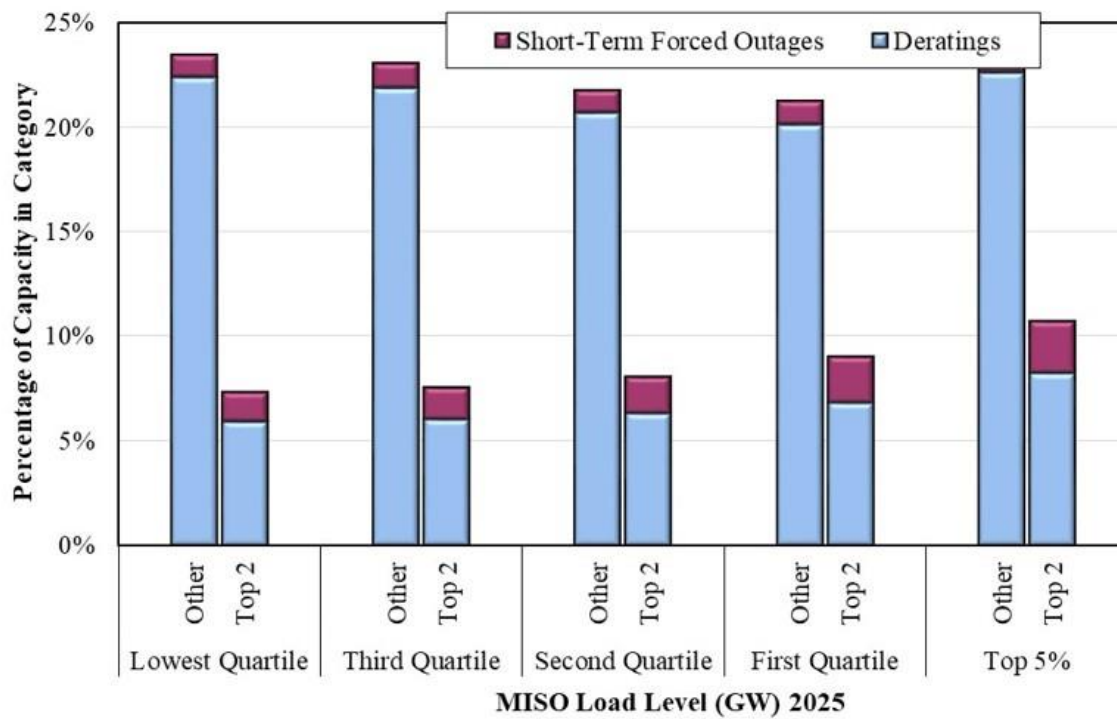
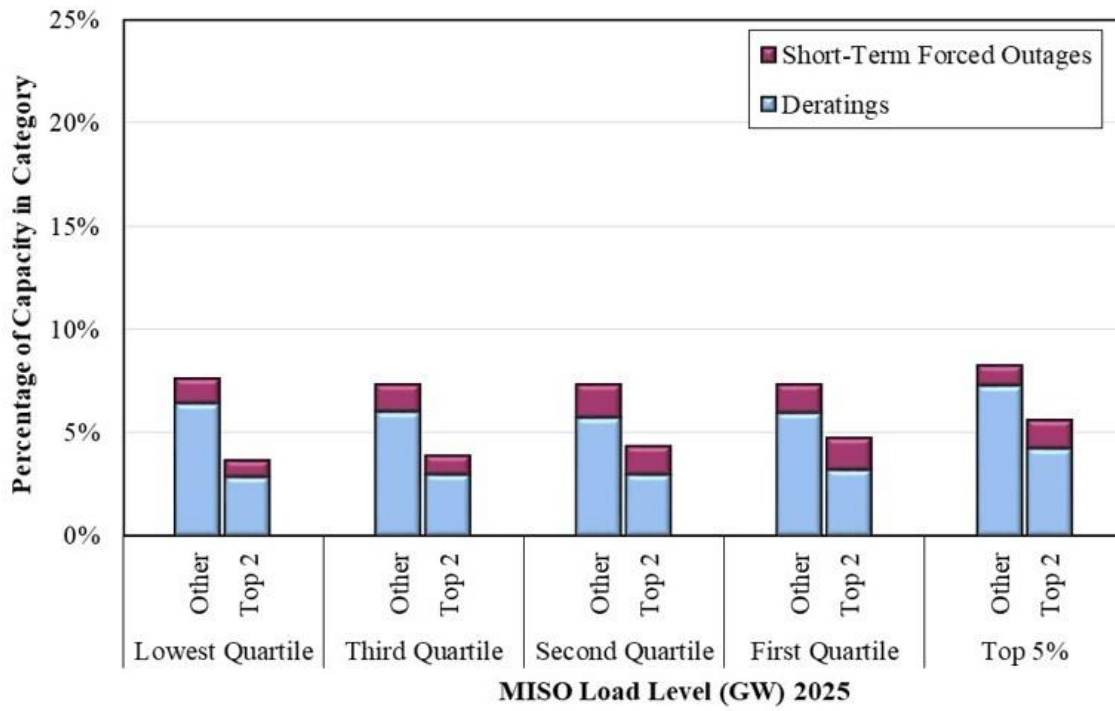


Figure A156: Real-Time Deratings and Forced Outages
North Region, 2025



IX. DEMAND RESPONSE PROGRAMS

Demand Response (DR) involves actions that reduce consumption when the value of consumption is less than the marginal cost of supplying electricity. DR allows end users to participate in the energy markets and contributes to short-term reliability, least-cost resource adequacy, and lower price volatility and other market costs. Even modest reductions in consumption by end users during high-priced periods can greatly reduce generation commitment and dispatch costs. These benefits underscore the value of facilitating DR through the wholesale markets.

A. Demand Response Participation in MISO

DR resources fall into two categories: a) Emergency DR, which responds to capacity shortages; and b) Economic DR, which responds to market schedules.

Emergency DR. MISO calls emergency demand response resources in anticipation of a system emergency to support reliability. However, emergency DR is not price-responsive and does not participate directly in the MISO markets. Emergency DR includes:

1. Load-Modifying Resources (LMRs) that must curtail during emergencies and satisfy planning reserve margin requirements (PRMR).
 - LMR-BTMG: These behind-the-meter generation assets do not have a direct interconnection to MISO.
 - LMR-DR: This category primarily includes legacy interruptible demand under regulated utility programs.
2. Emergency Demand Response Resources (EDRs) that MISO calls during emergencies but that need not offer and do not satisfy MISO's PRMR.

LMRs can also register as EDRs, which participate differently from LMRs. In 2025, MISO filed to eliminate cross-registration of LMRs as EDRs beginning in June 2026. EDRs submit offers in the day-ahead market. During emergency conditions, MISO selects offers in economic merit order based on offered curtailment prices, up to a \$3,500-per-MWh LMP cap. EDR participants who curtail demand are compensated at the greater of the prevailing real-time LMP or their offer costs (including shut down costs) for the amount of verifiable demand reduction provided. EDR resources are eligible to set price.

Economic DR. These resources respond to energy market prices not only during emergencies, but whenever energy prices exceed the marginal value of the consumer's electricity consumption. The real-time market is significantly more volatile than the day-ahead market because physical limitations limit its ability to respond to changes in load, interchange, and system contingencies, such as generator or transmission outages. DR resources tend to be more valuable in real time during shortage periods when prices rise sharply.

In the day-ahead market, prices are less volatile, and more supply alternatives are available. Consequently, DR resources are generally less valuable in the day-ahead market. Over the longer term, however, consumers can shift consumption patterns in response to day-ahead prices, such

as from peak to off-peak periods, thereby flattening the load curve. MISO limits economic DR to two types of Demand Response Resources (DRRs) that respond economically to prices in the energy and ancillary services markets:

- **DRR Type 1:** These resources can supply a fixed quantity of energy or contingency reserves through physical load interruption. They provide a “Target Demand Reduction Amount.” In ELMP, MISO includes DRR Type I resources as Fast-Start Resources, which may set prices if they meet the eligibility requirements.
- **DRR Type 2:** These resources supply varying levels of energy or operating reserves every five minutes and can set ex-ante prices. They are “dynamic pricing” resources—the most efficient form of DR because they set efficient prices throughout the day.

DRRs can participate in all MISO markets, including satisfying LSEs’ resource adequacy requirements under Module E of the Tariff. However, DRR Type I units cannot provide regulating reserves because of their operating limitations.

Table A19: Demand Response Capability in MISO and Neighboring RTOs

Table A19 shows the total DR capabilities of MISO and neighboring RTOs. Their differing requirements and responsiveness make individual classes of DR capability not comparable.

**Table A19: Demand Response Capability in MISO and Neighboring RTOs
2023–2025**

	2023	2024	2025
MISO¹	12,311	12,979	14,067
LMR-BTMG	4,129	4,143	4,283
LMR-DR	7,695	8,109	9,004
LMR-EE	5	23	28
DRR Type I	521	692	733
DRR Type II	79	75	75
<i>Total Cross-Registered as LMR</i>	<i>201</i>	<i>208</i>	<i>137</i>
Emergency DR	686	788	706
<i>Total Cross-Registered as LMR</i>	<i>603</i>	<i>643</i>	<i>624</i>
NYISO²	1,294	1,435	1,206
Special Case Resources - Capacity	1,282	1,433	1,206
Emergency DR	12	2	0
Day-Ahead DRP	0	0	0
ISO-NE³	3,798	3,674	3,257
Active Demand Capacity Resources	438	431	352
Passive Demand Resources	3,360	3,243	2,905

* All units are MW.

¹ Registered as of July for each year.

² Registered as of July for each year. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.

³ Capacity supply obligations as of July 2025. Source: ISO-NE Monthly Market Reports.

The table shows the following types of demand response for resources outside MISO:

- *Special Case Resources*: A demand response program in NYISO that helps maintain reliability by calling on electricity users to reduce consumption during shortage conditions.
- *Active Demand Capacity Resources*: Similar to DRRs in MISO, these resources respond to dispatch instructions by reducing load or using on-site generation.
- *Passive Demand Resources*: Non-dispatchable resources that reduce consumption across many hours or periods after being installed. These resources are primarily energy efficiency programs or distributed generation and participate in the ISO-NE capacity market as either “Seasonal Peak” or “On-Peak”.