2024 State of the Market Report for the MISO Electricity Markets

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Independent Market Monitor for the Midcontinent ISO

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Guide to Acronyms

AAR	Ambient Adjusted Rating	M2M	Market-to-Market
AMP	Automated Mitigation Procedure	MCC	Marginal Congestion Component
ARC	Aggregator of Retail Customers	MCP	Market Clearing Price
ARR	Auction Revenue Rights	MISO	Midcontinent Independent Sys. Operator
ASM	Ancillary Services Market	MMBtu	Million British thermal units
BCA	Broad Constrained Area	MSC	MISO Market Subcommittee
BTMG	Behind-The-Meter Generation	MVL	Marginal Value Limit
CDD	Cooling Degree Day	MW	Megawatt
CONE	Cost of New Entry	MWh	Megawatt-hour
CRA	Competitive Retail Area	NCA	Narrow Constrained Area
CROW	Control Room Operating Window	NERC	North American Electric Reliability Corp.
CTS	Coordinated Transaction Scheduling	NSI	Net Scheduled Interchange
DA	Day-Ahead	NYISO	New York Independent System Operator
DAMAP	Day-Ahead Margin Assurance Pmt.	ORDC	Operating Reserve Demand Curve
DIR	Dispatchable Intermittent Resource	PJM	PJM Interconnection, Inc.
DR	Demand Response	PRA	Planning Resource Auction
DRR	Demand Response Resource	PRMR	Planning Reserve Margin Requirement
ECF	Excess Congestion Fund	PVMWP	Price Volatility Make-Whole Payment
EDR	Emergency Demand Response	RAN	Resource Availability and Need
EEA	Emergency Energy Alert	RDT	Regional Directional Transfer
ELMP	Extended LMP	RPE	Reserve Procurement Enhancement
FERC	Federal Energy Reg. Commission	RSG	Revenue Sufficiency Guarantee
FFE	Firm Flow Entitlement	RT	Real-Time
FRAC	Fwd. Reliability Assessment Commitment	RTO	Regional Transmission Organization
FSR	Fast-Start Resource	RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Pmt.
FTR	Financial Transmission Right	SMP	System Marginal Price
GSF	Generation Shift Factor	SOM	State of the Market
HDD	Heating Degree Day	SPP	Southwest Power Pool
HHI	Herfindahl-Hirschman Index	SSR	System Support Resource
ICAP	Installed Capacity	STLF	Short-Term Load Forecast
IESO	Ontario Electricity System Operator	STR	Short Term Reserves
IMM	Independent Market Monitor	TCDC	Transmission Constraint Demand Curve
ISO-NE	ISO New England, Inc.	TLR	Transmission Line Loading Relief
JOA	Joint Operating Agreement	TO	Transmission Owner
LAC	Look-Ahead Commitment	TVA	Tennessee Valley Authority
LBA	Local Balancing Area	UCAP	Unforced Capacity
LMP	Locational Marginal Price	UDS	Unit Dispatch System
LMR	Load-Modifying Resource	VLR	Voltage and Local Reliability
LRZ	Local Resource Zone	VOLL	Value of Lost Load
LSE	Load-Serving Entity	WUMS	Wisconsin-Upper Michigan System

EXECUTIVE SUMMARY

As the Independent Market Monitor (IMM) for the Midcontinent Independent System Operator (MISO), we evaluate the competitive performance and efficiency of MISO's wholesale electricity markets. The scope of our work in this capacity includes monitoring for attempts to exercise market power or manipulate the markets, identifying market design flaws or inefficiencies, and recommending improvements to market design and operating procedures. This Executive Summary to the *2024 State of the Market Report* provides an overview of our assessment of the performance of the markets and summarizes our recommendations.

MISO operates competitive wholesale electricity markets in the Midcontinent region that extends geographically from Montana in the west, to Michigan in the east, and to Louisiana in the south. The MISO geographic footprint is shown to the right, with MISO South in blue and MISO Midwest in green.

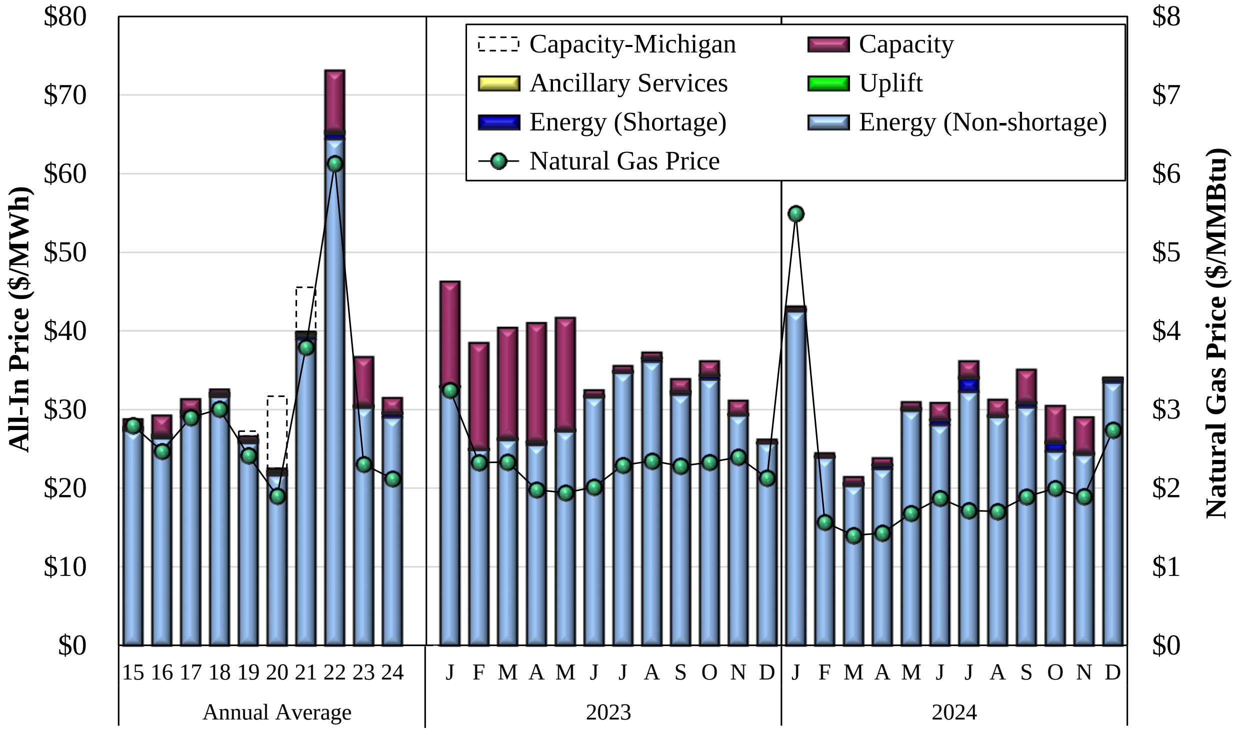
MISO launched its markets for energy and financial transmission rights (FTRs) in 2005, ancillary services market in 2009, and the capacity market in 2013. These markets coordinate the planning, commitment, and dispatch of generation to ensure that resources are meeting system demand reliably at the lowest cost.

Additionally, the MISO markets establish prices that reflect the marginal value of energy at each location on the network (i.e., locational marginal prices or LMPs). These prices facilitate efficient actions by participants in the short term (e.g., to make resources available and to schedule imports and exports) and support long-term decisions (e.g., investment, retirement, and maintenance). The remainder of this Executive Summary provides an overview of market outcomes, a discussion of key market issues, and a list of recommended improvements.

Summary of Market Outcomes and Competitive Performance

The MISO energy and ancillary services markets generally performed competitively in 2024. Multiple factors affected market outcomes, including lower average load, the continuing change in the resource mix, and lower natural gas prices. The figure below shows a 14 percent reduction in real-time energy prices throughout MISO, which averaged $31 per MWh. Multiple factors contributed to this decrease, including an eight percent decrease in natural gas prices. Average system load in 2024 was around 75 GW, similar to average system load in 2023.

All-In Price of Electricity



Frequent transmission congestion often caused prices to diverge throughout MISO. The value of real-time congestion fell by just one percent in 2024 and remained at $1.8 billion, largely because of lower natural gas prices and slightly higher average wind output compared to 2023. Wind output now contributes to about 40 percent of MISO's real-time congestion. Congestion also resulted in wind curtailments averaging approximately 607 MW per hour and as high as 6.2 GW in some hours.

Real-time congestion was higher than optimal because several key issues continue to encumber congestion management, including:

- Conservative static ratings by most transmission owners;
- Issues defining and coordinating market-to-market constraints;
- Frequent larger transmission derates by MISO operators;
- Reliance on manual dispatch instructions in cases where the real-time dispatch model can optimally dispatch and price the congestion; and
- MISO's limited authority to coordinate outages.

To address these concerns, we continue to recommend a number of improvements to lower the cost of managing congestion on MISO's system. These improvements promise some of the largest short-term benefits of any of the recommendations we make in this report.

Weather Events in 2024

MISO experienced three challenging weather events in 2024.

- In January, Winter Storm Heather created widespread operating impacts and challenges.
- In July, Hurricane Beryl caused extensive damage and associated operational issues in the South, while operational issues occurred in the Midwest on the same day.
- In August, the system reached its annual peak demand during an extended period of hot weather requiring Conservative Operations.

In general, MISO performed well during these events, maintaining reliability and avoiding costly out-of-market actions. We discuss and evaluate these events in Section II.E. of this report

Competitive Performance

Outcomes in the MISO markets continue to show a consistent correlation between energy and natural gas prices that is expected in a well-functioning, competitive market. Gas-fired resources are most often the marginal source of supply, and fuel costs constitute the vast majority of most resources' marginal costs. Competition provides a powerful incentive to offer resources at prices reflecting their marginal costs. We evaluate the competitive performance of the markets by assessing the suppliers' conduct using the following two empirical measures of competitiveness:

- A "price-cost mark-up" compares simulated energy prices based on actual offers to energy prices based on competitive offer prices. The price-cost mark-up was very small at negative three percent, indicating the markets were highly competitive.
- The "output gap" is a measure of potential economic withholding. It remained very low, averaging 0.06 percent of load, so market power mitigation was applied infrequently.

These results, as well as the results of our ongoing monitoring, confirm that the MISO markets are delivering the benefits of robust competition to MISO's customers.

Market Design Improvements

Although MISO's markets continue to perform competitively, we have identified a number of key areas that should be improved as MISO's generating fleet evolves in the coming years. Hence, this report provides several recommendations, four of which are new this year. MISO has continued to respond to past recommendations and implemented several key changes in 2024:

- Capacity Market: MISO transitioned to a seasonal market in 2024 and implemented reliability-based demand curves in early 2025. It is also reforming its resource accreditation to reflect resources' marginal contribution to the reliability of the system.
- Energy Market: MISO reformed its shortage pricing provisions to allow energy and ancillary service prices to better reflect the expected potential costs of load shedding.

- Market Operations: MISO made key changes in its commitment practices and operating procedures to manage congestion, which has greatly reduced inefficient uplift payments.

These changes will improve the performance of the markets and the operation of the system. We discuss these improvements and other recommendations throughout this report.

Future Market Needs

The MISO system is changing rapidly as the generating fleet transitions and new technologies enter the market. Although the nature and pace of the change is uncertain, MISO will have to adapt to new operational and planning needs. MISO has been grappling with these issues in several initiatives. In addition, the long period of low load growth appears to be ending and MISO now projects a growth rate of one to two percent per year over the next 20 years, which result in steadily increasing capacity needs. Fortunately, MISO's markets are robust and well-suited to meet these challenges without fundamental market changes. However, we discuss below some key incremental improvements that will be needed as this transition occurs.

Over the past decade, the penetration of renewable resources has steadily increased as baseload coal resources have retired. This trend is likely to accelerate as large quantities of solar, battery storage resources, and hybrid resources join new wind resources in the interconnection queue. The most significant supply-side challenges include:

- *Wind*: As wind generation increases, the volatility of its output grows as do the errors in forecasting the wind output.
- *Solar*: Solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years. This will lead to significant changes in the system's ramping needs for its dispatchable resources, particularly in the evening as the sun sets.
- *Energy Storage*: MISO is working to enable Energy Storage Resources (ESRs) to participate in the markets while recognizing their unique characteristics. Falling costs and rising price volatility should cause ESRs to be increasingly economic in the future.

MISO has already begun the process of making necessary changes to face these challenges, including the essential capacity and energy improvements described above. These improvements will help the markets facilitate the investment in new resources and retention of existing resources needed to satisfy the needs of the system. In addition, Section III.C recommends other important improvements to account for the rising system uncertainty and improve the utilization of the network as transmission flows become more volatile. The key recommended improvements include:

1. Energy and Ancillary Services Markets
    - Introducing an uncertainty product to reflect MISO's need to commit resources to have sufficient supply available in real time to manage uncertainty; and

- Implementing a look-ahead dispatch and commitment model in the real-time market.

2. Operation and Planning of the Transmission System
   - Improving the market-to-market coordination with its neighbors;
   - Introducing new processes to optimize the operation of the transmission system and improve its utilization by working to implement AARs by 2026; and
   - Improving the transmission planning processes and benefit-cost analyses.

Energy Market Performance and Operations

Day-Ahead Market Performance

The day-ahead market is critical because it coordinates most resource commitments and is the basis for almost all energy and congestion settlements with participants. Day-ahead market performance can be judged by the extent to which its prices converge with real-time prices. This facilitates efficient resource commitments that satisfy the system's operational needs. In 2024:

- The difference between day-ahead and real-time prices, including day-ahead and real-time uplift charges, was good at roughly two percent.
- However, episodes of congestion caused by generation and transmission line outages led to transitory periods of divergence at various locations.

Virtual transactions provided essential liquidity and improved the convergence of day-ahead and real-time energy prices. Average cleared virtual transactions in the Midwest and South decreased by six and four percent in 2024, respectively. Our evaluation of virtual transactions revealed:

- The vast majority of the virtual trading was by financial participants whose transactions were the most price sensitive and the most beneficial to the market;
- Most of the virtual transactions improved price convergence and economic efficiency in the day-ahead market based on our detailed assessment of the transactions; and
- Participants continued to submit price-insensitive matching virtual supply and demand transactions to arbitrage congestion differences. The virtual spread product we continue to recommend would facilitate this arbitrage in a more efficient, lower-risk manner.

Real-Time Market Performance and Price Formation

The performance of the real-time market is crucial because it governs the dispatch of MISO's resources. The real-time market sends economic signals that facilitate scheduling in the day-ahead market and longer-term investment and retirement decisions. Efficient price signals during shortages and tight operating conditions provide incentives for resources to be flexible and perform well. Shortage pricing will be increasingly important as intermittent resources continue to grow. Shortage pricing also reduces resources' reliance on revenues from the capacity market to maintain resource adequacy. Hence, MISO's ORDC reforms are essential.

In addition to shortage pricing, its ELMP pricing model plays a key role in achieving efficient price formation by allowing online fast-start peaking resources (FSRs) and emergency supply to set prices when they are economic. Section IV.C of this report shows that the average effect of ELMP on MISO's real-time energy prices was $0.72 per MWh in 2024, lower than in prior years because of the lower energy and natural gas prices.

MISO's emergency pricing is generally efficient and effective by allowing emergency capacity and actions to set prices during emergencies. However, pricing when large quantities of LMRs are deployed can be substantially overstated because the ELMP model cannot ramp other units up quickly enough to replace them. To address this concern, we recommend MISO reintroduce LMR curtailments as an STR demand instead of energy demand. This will allow the ELMP model to more accurately determine whether LMRs are needed and should set prices.

Uplift Costs in the Day-Ahead and Real-Time Markets

Evaluating uplift costs is important because they are difficult for customers to forecast and hedge, and uplift costs generally reveal areas where the market prices do not fully capture the needs of the system. Most uplift costs are the result of two primary forms of guarantee payments made to ensure resources cover their as-offered costs and provide incentives to be flexible:

- Revenue Sufficiency Guarantee (RSG) payments ensure that a resource's market revenue is at least equal to its as-offered costs over its commitment period; and
- Price Volatility Make-Whole Payments (PVMWP) ensure suppliers will not be financially harmed by following the five-minute dispatch signals.

Day-ahead RSG. These payments fell eight percent to $30 million, the majority of which are Voltage and Local Reliability (VLR) costs incurred in two load pockets in MISO South.

Real-time RSG. These payments fell 18 percent in 2024, largely driven by lower fuel costs and operational improvements in MISO's out-of-market resource commitments.

PVMWPs. These costs increased in 29 percent from 2023 as ancillary services shortages caused frequent price spikes in 2024, which can generate significant DAMAP costs.

Real-Time Generator Performance

We monitor and evaluate the poor performance of some generators in following MISO's dispatch instructions on an ongoing basis. Accounting for poor performance over a period of an hour, the accumulated dragging by MISO's generators (producing less output than had they followed MISO's instructions) averaged over 770 MW in all hours and over 1100 MW in the worst 10 percent of hours. This continues to raise economic and reliability concerns because these deviations are often not detected by MISO's operators. The largest source of dispatch deviations are wind resources, which is due to: (a) forecast errors and (b) the fact that wind resources causing congestion are economically indifferent to following dispatch or do not receive a clear indication they are being curtailed.

Section IV.F provides an example of the latter, which can result in severe transmission violations and compel MISO to use out-of-market actions. To address this issue, we propose a deviation penalty based on the marginal congestion component (MCC) of the resource's LMP that is described in Section IV.F. An MCC-based penalty is appropriate because it reflects the congestion value of the deviation volumes and scales with the severity of congestion. Our analysis of this proposal shows that it would produce very small penalties for most types of resources, but it would also produce the largest penalties for the wind resources that are deviating and causing constraint violations.

Additionally, MISO is implementing a dispatch flag for intermittent resources that will clearly indicate when resources are contributing to loading a binding constraint. This penalty and the development of other settlement rules associated with this flag should be prioritized to improve MISO's operational control of the system through the real-time market.

Wind Generation and Forecasting

Installed wind capacity now accounts for almost 30 GW of MISO's installed capacity and produced 15 percent of all energy in MISO in 2024. Average hourly wind output increased by 10 percent to 11.2 GW per hour compared to 2023 and was 22 percent higher than three years ago. MISO set its all-time wind record in early 2024 at more than 25 GW. These trends in wind output are likely to continue as investment remains strong. The report identifies operational and market issues associated with the growth of wind resources.

Day-Ahead Scheduling. Wind suppliers generally under-schedule their output in the day-ahead market, averaging roughly 1,100 MW less than their real-time output. This may be attributed to the suppliers' contracts and the financial risk related to RSG allocations to over-scheduled wind. Under-scheduling can undermine price convergence and resource commitments, which is partly addressed by virtual suppliers that sell day-ahead energy in place of the wind suppliers.

Real-Time Wind Forecasting. One of MISO's operational challenges is the large dispatch deviations that can be caused by wind forecast errors. The unit's forecast is used by MISO to set the unit's dispatch maximum and, because wind offer prices are low, the forecast also tends to determine the dispatch level. Dispatch deviations caused by wind forecast errors contribute to higher congestion and under-utilization of the transmission network and cause non-wind resources to be dispatched at inefficient levels.

Most wind resources rely on the MISO forecast in real time, which we evaluate in this report. We find that MISO's simple persistence forecast (i.e., the most recently observed wind output will continue) tends to often produce large errors. Our evaluation shows that improving the persistence-based forecast by incorporating the recent direction in output changes would substantially improve the MISO forecast – reducing the frequency of the highest portfolio-level errors by more than 90 percent. Improving the real-time wind forecast will be increasingly important as the penetration of intermittent resources increases. MISO has developed design requirements to improve the forecast methodology and plan to implement it in 2025.

Transmission Congestion and FTR Markets

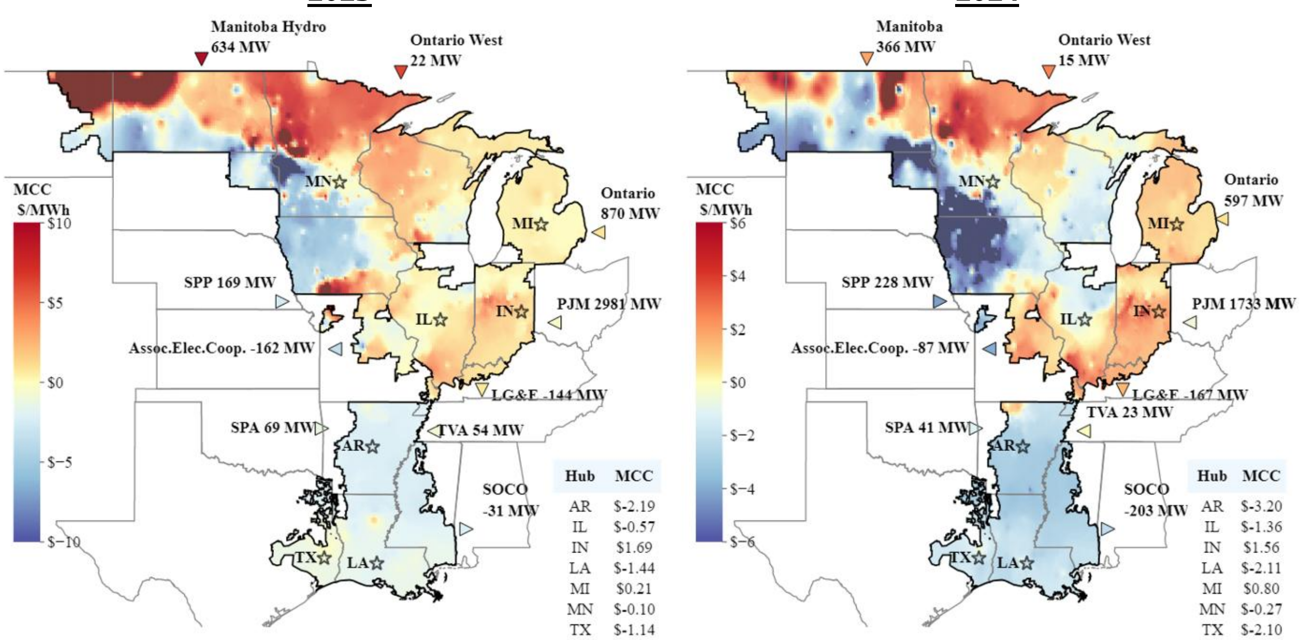
Transmission congestion costs arise on the MISO network when a higher-cost resource is dispatched in place of lower-cost ones to avoid overloading transmission constraints. These congestion costs arise in both the day-ahead and real-time markets. These costs are reflected in MISO's location-specific energy prices, which represent the marginal costs of serving load at each location given the marginal energy costs, network congestion, and losses. Because most transactions are settled through the day-ahead market, most congestion costs are collected in this market. The maps below show the changes in congestion patterns between 2023 and 2024.

Congestion Costs in 2024

The value of real-time congestion fell by one percent in 2024 and remained at $1.8 billion, largely because of the decline in natural gas prices that was offset by slightly higher wind output. The maps below show the year-over-year changes in congestion patterns from 2023 to 2024.

Average Real-Time Congestion Components in MISO's LMPs

2023 **2024**



Not all of the $1.8 billion in real-time congestion cost is collected by MISO through its markets, primarily because there are loop flows caused by external areas and flow entitlements granted to PJM, SPP, and TVA under JOAs, resulting in uncompensated use of MISO's network. Hence, day-ahead congestion costs were $1.3 billion in 2024, an increase of 10 percent from 2023.

Day-ahead congestion revenues are used to fund MISO's FTRs. FTRs represent the economic property rights associated with the transmission system and serve as a hedge against day-ahead congestion costs. Efficient FTR markets will set prices that reflect an accurate expectation of day-ahead congestion. The FTR markets have not always performed well in this regard, particularly in the MPMP and monthly auctions. We discuss two factors that have affected the performance of the annual and monthly FTR auctions:

- The accuracy of the network topology, which depends to a large extent on the completeness of the transmission outages information; and
- The liquidity of the FTR auctions.

Outage Reporting. Transmission owners are required to schedule outages with MISO 12 months in advance, which some fail to schedule. In addition, some outages are not known far in advance. This causes the outages reflected in the annual FTR auction to be much less complete than in the monthly auctions. Additionally, MISO is compelled to be conservative – an outage scheduled for longer than 5 days is assumed to occur over the entire season in which it occurs. The modeling of the network is much more accurate in the monthly and seasonal timeframes because most planned outages are known by then.

Participation and Liquidity. Although the network topology is much more accurate in the MPMA and monthly auction timeframes, the poor liquidity of these markets cause them to generally perform more poorly in setting prices that reflect congestion in the day-ahead market. Liquidity is greater in the annual auction because LSE's receive their ARR allocations prior to the annual auction and can offer to convert their allocations to FTRs through the annual auction.

In order to allow participation of customers in the seasonal and monthly FTR auctions where the outage is much more complete, we recommend that MISO:

- Make a smaller share of the transmission capacity (e.g., one third) available for allocation as ARRs and for sale in the Annual FTR Auction, down from 90 percent currently;
- Release additional transmission capacity to be allocated as ARRs and sold as FTRs in seasonal and monthly FTR auctions (e.g., half of the remaining capacity in each); and
- Modify the ARR allocation process to better align with customer's current use of the system and facilitate allocations of capability that would otherwise be unallocated under the current generation to load nomination process.

By shifting transmission capability into the seasonal or monthly auctions, the liquidity and performance of these markets will improve, and customers will likely receive a higher share of the full value of the system. This will also greatly reduce the likelihood that constraints will be oversold in the annual auction, which can lead to FTR shortfalls.

Congestion Management Concerns and Potential Improvements

Although overall there have been improvements in MISO's congestion management processes, we remain concerned about a number of issues that undermine the efficiency of MISO's management of transmission congestion. Given the vast costs incurred annually to manage congestion, initiatives to improve congestion management are likely to be among the most beneficial. Hence, we encourage MISO to assign a high priority to addressing these issues.

Outage Coordination. Transmission and generation outages often occur simultaneously and affect the same constraints. Multiple simultaneous generation outages contributed to $540 million in real-time congestion costs in 2024 – 29 percent of real-time congestion costs. We continue to recommend MISO explore improvements to its coordination of transmission and generation outages, including expanding its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages.

Understated Transmission Ratings. Most transmission owners still do not actively adjust their facility ratings to reflect ambient temperatures or provide emergency ratings for contingent constraints (when the actual flow would temporarily approach this rating only after the contingency). As a result, MISO often uses lower fixed ratings, which reduces MISO's utilization of its transmission network. We estimate MISO could have saved over $230 million in congestion costs in 2024 by using temperature-adjusted and emergency ratings. FERC extended the deadline to 2028 for compliance with Order 881, which required these improvements. Nonetheless, we continue to urge MISO and the TOs to provide improved real-time AARs under the existing interface or the system MISO is developing that should be completed in early 2026.

Transmission Reconfiguration. It can often be highly economic to alter the configuration of the network (e.g., opening a breaker) to reduce flows on a severely constrained transmission facility. This is done currently to mitigate reliability concerns under procedures established with the transmission owners impacted by the reconfiguration. Such procedures should be expanded to economically manage congestion as they can mitigate or eliminate severe congestion on some constraints. MISO has established a process to evaluate potential reconfiguration options proposed by participants. We recommend MISO develop a tool to identify such options itself.

Generator Decommitments. Based on an analysis of the value of decommiting resources that are causing congestion, we recommend MISO use the LAC and modify its procedures to identify and decommit resources.

RDT Pricing. To manage congestion between the MISO South and Midwest regions efficiently, we recommend that MISO modify the RDT Transmission Constraint Demand Curve (TCDC) by adding lower-valued steps and raising the energy plus STR limit to align with the highest penalty step on the TCDC. These demand curve adjustments will increase RDT utilization.

Market-to-Market Coordination

There are many MISO constraints that are greatly affected by generation in PJM and SPP, and likewise constraints in these areas that are affected by MISO generation. Therefore, MISO coordinates congestion management on these constraints through the market-to-market (M2M) process with SPP and PJM. Congestion on MISO's M2M constraints totaled $641 million in 2024, which was more than 30 percent of all congestion in MISO.

It is essential that M2M coordination operate as effectively as possible and we evaluate the M2M process by tracking the convergence of the shadow prices of M2M constraints. When the process is working well, the "non-monitoring RTO" (NMRTO) will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the shadow price of the "monitoring RTO" (MRTO) responsible for managing the constraint.

M2M coordination has generally contributed to shadow price convergence over time and lowered the costs of managing congestion. However, we also find that coordination could be improved with the following key changes and deliver substantial additional savings.

- *Relief request software*. Improving the software used to determine the amount of relief requested from the NMRTO would provide significant savings. The current process often produces suboptimal relief quantities that prevent the NMRTO from providing all available economic relief. Based on our analysis of this issue with SPP, we find that improving the relief requests would generate over $60 million in annual savings.
- *Five-percent test*. M2M constraints are identified when the NMRTO places substantial market flows on the constraint or has at least one generator with a GSF greater than five percent on the constraint. The latter has frequently caused constraints to be defined as M2M with extremely small benefits. Hence, we recommend that MISO replace the five-percent test with a test based on the NMRTO's relief capability on the constraint.
- *Automation of the M2M Processe*s. Given that much of the M2M process is implemented manually, there are significant opportunities to improve the timeliness with which constraints are tested and activated by increasing the automation of the M2M processes.
- *Day-Ahead Coordination*. The convergence of M2M constraints is poor in the day-ahead market. MISO and PJM implemented a process to coordinate and exchange FFEs in the day-ahead market, but do not actively use this process. We recommend MISO work with SPP and PJM to implement FFE exchanges on M2M constraints.

- *Reverse-Role Flowgates*. MISO and neighbors can agree to transfer the monitoring of M2M constraints, which are referred to as reverse-role flowgates. Ideally, this should occur only when the NMRTO has the majority of economic flow relief on the constraint. To address concerns, we have identified with this process, we recommend MISO: (1) adopt criteria for agreeing to accept reverse-role flowgates, and (2) condition acceptance of monitoring responsibility on the reasonable use of the relief request software.

Operator Actions

MISO operators are responsible for maintaining reliability, which can require operator actions. This actions can have sizable impacts on market outcomes and generate significant costs. Many of these actions are taken to manage congestion and address constraint violations, including:

- Derating transmission facilities through "limit control" adjustments. These incidents should be minimized because their cost can be substantial ($144 million in 2024); and
- Manual re-dispatch (MRD) of resources or capping their output.

We continued to work collaboratively with MISO in 2024 to improve procedures governing these actions. This collaboration has resulted in significant improvement. MISO also is working on other changes to improve the markets ability to manage congestion, which should also reduce the need for these actions.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

The capacity surplus MISO had enjoyed prior to the 2024–25 Planning Year dwindled in recent years as the retirements of baseload resources have mostly been replaced with intermittent renewable resources. In 2024, MISO experienced the following additions and retirements:

- 2 GW of resources retired or suspended operations, mostly coal and gas steam resources, some of which could return as new generation (e.g., solar, gas or energy storage).
- 2 GW of new unforced capacity entered MISO, 1.8 GW of which were solar resources. This more than doubled MISO's existing solar capacity. The other additions include 150 MW of new Electric Storage Resources (ESRs).

Planning Resource Auction Results

In the 2024-25 PRA, across the four seasons, market clearing prices averaged roughly $20 per MW-day. However, Zone 5 was short of its local clearing requirement (LCR) in the fall and spring because of the retirement of two large coal-fired resources at the end of the summer and long-duration planned outages in those shoulder seasons. This resulted in capacity prices of $720 per MW-day that is based on the annual CONE value.

In the 2025-26 PRA, MISO implemented downward sloping RBDCs. Across the four seasons, market clearing prices average nearly $215 per MW-day, ranging from $33.20 per MW-day in the winter to a high of $666.50 per MW-day in the summer. These prices are much more efficient, reflecting the prevailing reliability value of capacity in MISO, and will facilitate the investment in new resources and retention of existing resources that MISO will need to meet the growing demand for capacity in the coming years.

Long-Term Signals: Net Revenues

Market prices should provide economic signals that govern participants' long-run investment, retirement, and maintenance decisions. These signals can be measured by the "net revenues" generators receive in excess of their production costs. We evaluate these signals by estimating the net revenues that different types of new resources would have received in 2024.

- Net revenues fell for both new combustion turbines and combined-cycle resources in most zones in 2024, largely because lower natural gas prices contributed to lower energy and ancillary services prices throughout MISO and lower capacity prices in the Midwest.
- MISO's economic signals had been undermined by the poor representation of demand as a single quantity value (i.e., a vertical demand curve), which has been addressed by the implementation of the RBDC in 2025.
- These signals had also been reduced by inefficiently low shortage pricing, which MISO will address later in 2025 by substantially improving its operating reserve demand curves.

Capacity Market Design Improvements

In addition to the significant improvements implemented over the past two years, MISO will be changing its framework to accredit resources based on their marginal reliability value for reducing potential load shedding events. This is an essential change that has been approved by FERC and will be implemented in the 2028–29 Planning Year. We have also recommended several other changes to improve the accuracy of the supply and demand in the PRA, including:

- Improving the accreditation rules for emergency-only resources in the PRA;
- Defining capacity zones based on significant electrical constraints; and
- Modeling constraints in the PRA by assigning a zonal shift factor for each modeled constraint that reflects how the resources in each zone affect the flow on the constraint.

These improvements, along with the changes to the capacity demand curve and accreditation methodologies, will allow the PRA to provide efficient economic signals to help ensure that the MISO region remains reliable as its generation fleet transitions.

Long Range Transmission Planning

Transmission investment that is needed to support the reliable and economic operation of the system is essential and MISO takes the lead in planning such investment for the MISO region. In December 2024, the MISO Board approved Tranche 2.1 of its Long Range Transmission Plan (LRTP), which includes more than $20 billion projects. This follows more than $10 billion approved for Tranche 1 in 2022.

It will be increasingly important that these investments are economically efficient because: a) large-scale investment is very costly; and b) inefficient upgrades can undermine suppliers' incentives to make resource investment and retirement decisions that would mitigate congestion at lower costs and satisfy the energy needs of the system.

In evaluating the development and evaluation of Tranche 2.1, we discussed significant concerns with MISO and its participants:

- *Future 2A is not realistic.* Future 2A is the basis for identifying the Tranche 2 projects and evaluating their benefits and is unrealistic because it: (i) predicts an excessive amount of intermittent renewable resources will be built that are not planned by the states, and (ii) understates investment in dispatchable and storage resources. This is a problem because it tends to substantially increase the perceived need for transmission.
- *Many of the proposed categories of benefits are likely to be overstated*. MISO estimated nine classes of savings. The most pervasive concern is that MISO does not account for the fact that, absent the Tranche 2 investments, the market cause resources to enter in different locations that would likely mitigate MISO's transmission needs and lower the true benefits of Tranche 2. We also found that the to largest classes of benefits, accounting for two-thirds of all benefits, were not calculated properly and would likely not deliver a meaningful amount of benefits.

We found that the concerns described above introduced a substantial bias in favor of large-scale transmission facilities, a substantial share of which may not ultimately be economic. Hence, we recommend that MISO reform its planning process to address these concerns in future Tranches.

External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2024, importing an average of 2.6 GW per hour in real time over all interfaces and 1.9 GW per hour from PJM. Price differences at the interfaces between MISO and neighboring areas create incentives to schedule imports and exports between areas. We evaluate interface pricing in this report because of the key role it plays in facilitating external transaction scheduling, as well as coordinated transaction scheduling with PJM. Efficient interchange is essential because poor interchange can reduce dispatch efficiency, increase uplift costs, and can create operating reserve shortages.

Interface pricing. Our evaluation of interface pricing shows that the prices at the PJM and SPP are not fully efficient for different reasons. At the PJM interface, the RTO's have implemented a "common interface" that assumes power associated with imports and exports is sourced and sinks near the seam, which is not accurate. At the SPP interface, the value of M2M constraints is included redundantly in both RTOs' interface prices, which distorts the incentive to import and export. Hence, we recommend changes to MISO's interface pricing to address these issues.

Interchange Coordination. Coordinated Transaction Scheduling (CTS) is designed to improve interchange coordination. CTS allows participants to submit offers to transact within the hour if the forecasted spread in the RTOs' real-time interface prices is greater than the offer price. MISO currently has CTS with PJM. CTS participation has been minimal because of high transmission charges and persistent forecast errors that have likely deterred traders from using CTS. We recommend that MISO adopt the following improvements and implement CTS with SPP:

- Eliminate all transmission and other charges applied to CTS transactions, while encouraging PJM to do the same; and
- Modify the CTS to clear transactions every five minutes through the real-time dispatch model based on the five-minute dispatch cases for MISO and its neighboring RTOs.

Our discussion of CTS and the benefits of these changes is in Section VII.B. It shows that CTS would have raised the production cost savings in 2024 to nearly $25 million. We estimate savings of $35 million for a similar approach with SPP. This Section also describes a possible approach for using the simultaneous real-time dispatch cases to optimize the interchange, which would produce even larger savings. Such an approach would also likely reduce ramp and reserve shortage-related price volatility, which has been increasing with greater renewable penetration.

Demand Response and Energy Efficiency

Demand response is an important contributor to MISO's resource adequacy. MISO had 13 GW of DR resources in 2024, which included 4.1 GW of behind-the-meter generation. Most of its DR capability is in the form of interruptible load developed under regulated utility programs. DR resources are registered in three primary MISO programs depending on their capabilities.

Load-Modifying Resources (LMRs). Almost 95 percent of MISO's DR resources are LMRs that can only be accessed after MISO has declared an emergency. MISO has recently made several changes to improve the accessibility and information on the availability of LMRs, as discussed in Section IX.A. Although they are clear improvements, we still have concerns that LMRs are not as accessible or as valuable as generating resources from a reliability perspective. Hence, we are working with MISO to make further improvements to the accreditation and obligations of LMRs.

Demand Response Resources (DRRs). DRRs are a category of DR that can participate in the energy and ancillary services markets because they are assumed to be able to respond to MISO's real-time curtailment instructions. DRRs are divided into two subcategories:

- Type I: These resources can supply a fixed quantity of energy or reserves by interrupting load. These resources can qualify as FSRs and set price in ELMP[1]; and
- Type II: These resources can supply varying levels of energy or operating reserves on a five-minute basis and are eligible to set prices, just like generating resources.

Payments to DRRs fell sharply over the past two years as resources that we had previously investigated and referred to FERC for market manipulation ceased participating. This caused payments to DRRs to fall to just $3.2 million in 2023 and $4.8 million in 2024. Our monitoring of anomalous outcomes in DR performance has raised significant concerns regarding the market rules, the inefficient incentives they provide, and the resulting participant conduct. We identified two types of problematic conduct: a) payments for artificial "curtailments" of load the DRR never consume; and b) inflating the baseline level for the DRR by causing only high load to be included in the baseline. These are discussed in detail in Section IX.B.

The two market participants who engaged in these strategies both settled with FERC in 2023 and 2024 for more than $100 million. These cases illustrate the inherent problems of allowing demand to participate as supply in the market. To address these concerns, we recommended MISO revise its DRR rules and Tariff provisions to provide efficient incentives and to ensure that all payments made to DRRs result in real curtailments, and in 2025 MISO has begun a series of significant reforms.

Emergency Demand Response Resources (EDRs). These are called in emergencies but are not obliged to offer and do not satisfy capacity requirements unless cross-registered as LMRs.

Energy Efficiency (EE). MISO also allows energy efficiency to qualify to provide capacity. It is important that payments to EE be justified, and that the accreditation of EE is accurate. We have concerns in both regards, finding that:

- Making capacity payments for assumed load reductions provides compensation that is redundant to customers' retail electricity bill savings and is, therefore, not efficient;
- MISO must be able to accurately calculate how much the load has been reduced by EE in peak hours, which is inevitably based on an array of speculative and highly uncertain assumptions; and
- The existing program can result in sizable cost shifting by causing other LSEs to pay for EE capacity payments that are benefiting one LSE.

1 A resource can qualify as a Fast-Start Resource provided the DRR Type I resource can curtail demand within 60 minutes and offers a minimum run time of less than or equal to one hour.

Previously, the IMM performed an audit of EE capacity that had been sold in the PRA and found that (a) The EE resources audited did not actually reduce MISO's peak demand, (b) virtually all of the claimed savings were associated with product purchases by others that would have occurred without the EE resource, and (c) the claimed savings were not reasonably verified as the Tariff requires.

We referred this matter to FERC and in December 2024 FERC issued an Order to Show Cause and Notice of Proposed Penalty of nearly $1 billion against the participant. Most of this penalty is based on the revenues earned in other capacity markets. Fortunately, MISO's customers paid only $17 million to this participant before we identified the conduct and MISO disqualified them from participating in future PRAs.

However, since MISO's EE program is not addressing a known inefficiency and the quantities are difficult to accurately estimate or verify, we continue to recommend that MISO disqualify EE from selling capacity in MISO. PJM recently removed EE from its capacity market.

Table of Recommendations

Although the markets performed well in 2024, we make 34 recommendations to further improve their performance. Four are new, while 30 were recommended previously. MISO addressed or we have withdrawn six recommendations since our last report. The table below shows the recommendations by market area, numbered with the year they were introduced and the recommendation number in that year. We also indicate those with the highest benefits or that are possible in the near term.

SOM Number	Recommendations	High Benefit	Near Term
Energy and Operating Reserves and Guarantee Payments			
2024-1	Modify RDT demand curve steps and RPE binding limits.		✓
2023-1	Align aggregate pricing nodes in the FTR market through real-time.		✓
2023-2	Enforce STR requirements in the load pockets.		
2021-2	Evaluate reintroducing LMR curtailments as STR demand in pricing models and UDS.		
2020-1	Develop a real-time capacity product for uncertainty.	✓	
2012-3	Remove external congestion from interface prices.		✓
2012-5	Introduce a virtual spread product.		

SOM Number	Recommendations	High Benefit	Near Term
Transmission Congestion			
2024-2	Shift a large share of transmission capability from the annual ARR allocation and FTR auction to seasonal and monthly auctions	✓	
2024-3	Limit acceptance of transferred M2M flowgates to those where MISO has more effective relief and require proper use of the relief request software		
2023-3	Develop tools to recommend decommitment of resources committed in the day-ahead market.		
2022-1	Expand the TCDCs to allow MISO's market dispatch to reliably manage network flows.	✓	✓
2021-1	Work with TOs to identify and deploy economic transmission reconfiguration options.		✓
2019-1	Improve the relief request software for M2M coordination.		
2019-2	Improve the testing criteria defining market-to-market constraints.		
2016-3	Enhance authority to coordinate transmission and generation planned outages.		
2014-3	Seek joint operating agreements with neighboring control areas to improve congestion management and emergency coordination.		
Market and System Operations			
2024-4	Improve constraint management and dead bus criteria for Forced Off Asset Events		
2023-5	Require descriptions in new or updated CROW tickets.		
2022-3	Improve excess and deficient energy penalties to improve generators' incentives to follow MISO's dispatch instructions	✓	
2021-3	Evaluate and reform the unit commitment processes.		✓
2021-4	Develop a look-ahead dispatch and commitment model to optimally manage fluctuations in net load and the use of storage resources.	✓	
2020-2	Align transmission emergency and capacity emergency procedures and pricing.		✓
2019-4	Clear CTS transactions every five minutes through the UDS based on the RTOs' most recent five-minute prices.	✓	
2018-4	Clarify the criteria and improve the logging for declaring emergencies and taking emergency actions.		✓
2017-2	Remove transmission charges from CTS transactions.	✓	✓
2017-4	Improve operator logging tools and processes related to operator decisions and actions.		
2016-6	Improve the accuracy of the LAC recommendations and record operator response to LAC recommendations.	✓	✓

SOM Number	Recommendations	High Benefit	Near Term
Resource Adequacy and Planning			
2023-6	Implement zonal capacity demand curves and near-term improvements in local clearing requirements.	✓	
2022-4	Improve the LRTP processes and benefit evaluations.	✓	✓
2022-5	Implement jointly optimized annual offer parameters and improve outage penalty provisions in the seasonal PRA.		
2020-4	Develop marginal accreditation methodologies to accredit DERs, LMRs, battery storage, and intermittent resources.	✓	
2019-5	Improve the Tariff rules governing Energy Efficiency and their enforcement.		✓
2015-6	Improve the modeling of transmission constraints in the PRA.		
2014-6	Define local resource zones based on transmission constraints and local reliability requirements.		

I. Introduction

As the Independent Market Monitor (IMM) for MISO, we evaluate the competitive performance and operation of MISO's electricity markets. Overall, we found that the markets performed competitively and have been evolving to meet the challenges that lay ahead. This annual report summarizes our evaluation and provides our recommendations for future improvements.

MISO operates wholesale electricity markets designed to efficiently satisfy the needs of the MISO system, which encompasses parts of 15 states in the Midwest and South. The MISO markets include:

Day-Ahead and Real-Time Energy and Ancillary Services Markets – that utilize the lowest-cost resources to satisfy the system's demands and manage flows over the transmission network, while providing economic signals to govern short- and long-run decisions by participants. These markets jointly optimize the scheduling of resources to produce energy and provide ancillary services, including contingency reserves, short-term reserves, and regulation.

Financial Transmission Rights (FTRs) Market – facilitates the sale of FTRs that provide holders an entitlement to day-ahead congestion revenues, allowing them to hedge congestion.

Capacity Market – provides the economic signals needed to satisfy the resource adequacy requirements of the system and is implemented through the Planning Resource Auction (PRA).

The energy and ancillary services markets provide a robust foundation for the long-term challenges that lie ahead. Nonetheless, we identify a number of potential improvements that will allow the markets to operate more efficiently and provide better economic signals. MISO continued to respond to our past recommendations in 2024. Key improvements included:

- Capacity Market: MISO transitioned to a reliability-based demand curve in early 2025 and is reforming its resource accreditation to reflect resources' marginal contribution to the reliability of the system in the riskiest hours.
- Energy Market: MISO is reforming its shortage pricing provisions to allow energy and ancillary service prices to better reflect the expected potential costs of load shedding.
- Market Operations: MISO made key changes in its commitment practices and operating procedures to manage congestion, which has greatly reduced inefficient uplift payments.

These changes have improved the performance of the markets. We discuss other recommended changes in Section X of the Report to improve the design and operations of MISO's market, which will position MISO to successfully navigate the transition of its generating fleet.

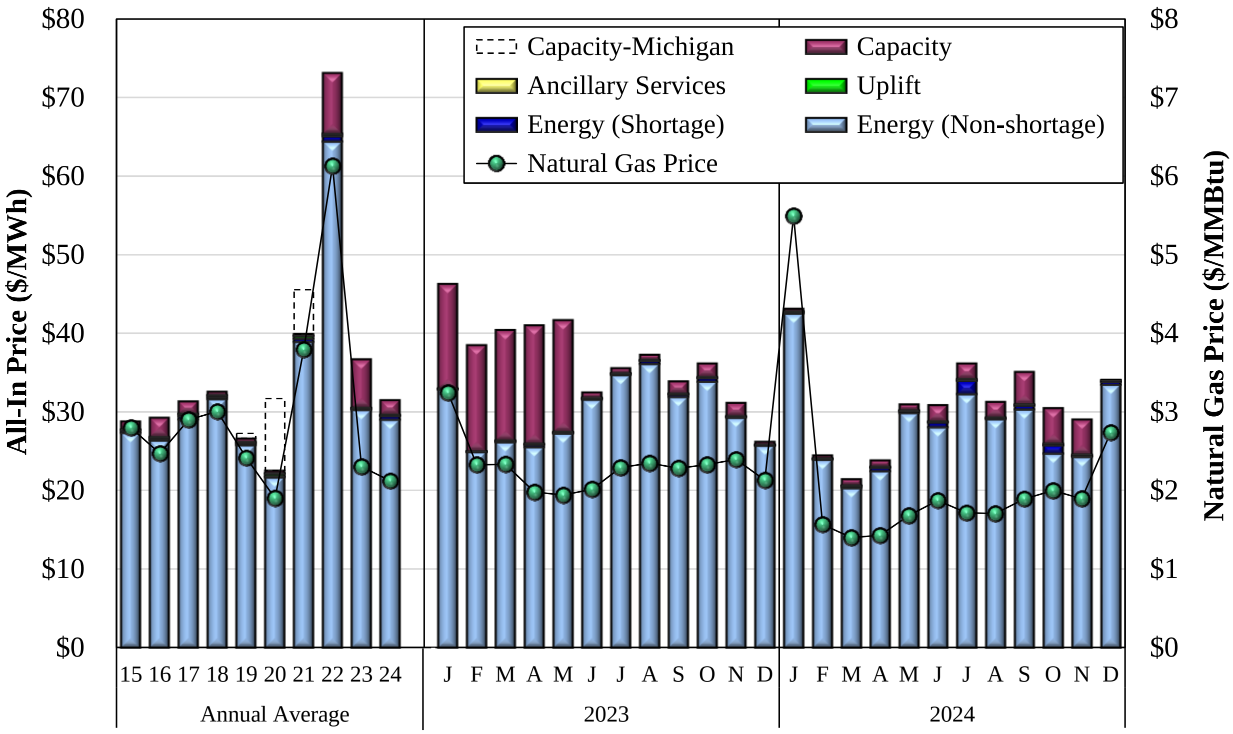
II. Price and Load Trends

MISO's wholesale electricity markets in the day-ahead and real-time timeframes facilitate the efficient commitment and dispatch of resources to satisfy the needs of the MISO system. The resulting prices also play a key role in providing short- and long-term incentives for MISO's participants. This section reviews overall prices, generation, and load in these markets.

A. Market Prices in 2024

Figure 1 summarizes changes in energy prices and other market costs by showing the "all-in price" of electricity, which is a measure of the total cost of serving load from MISO's markets. The all-in price is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load.[2] We separately show the portion of the all-in price that is associated with energy shortage pricing. The load-weighted average capacity clearing prices are represented in the maroon bars. Figure 1 also shows average natural gas prices to highlight the trend in the relationship between natural gas and energy prices.

Figure 1: All-In Price of Electricity
2023–2024



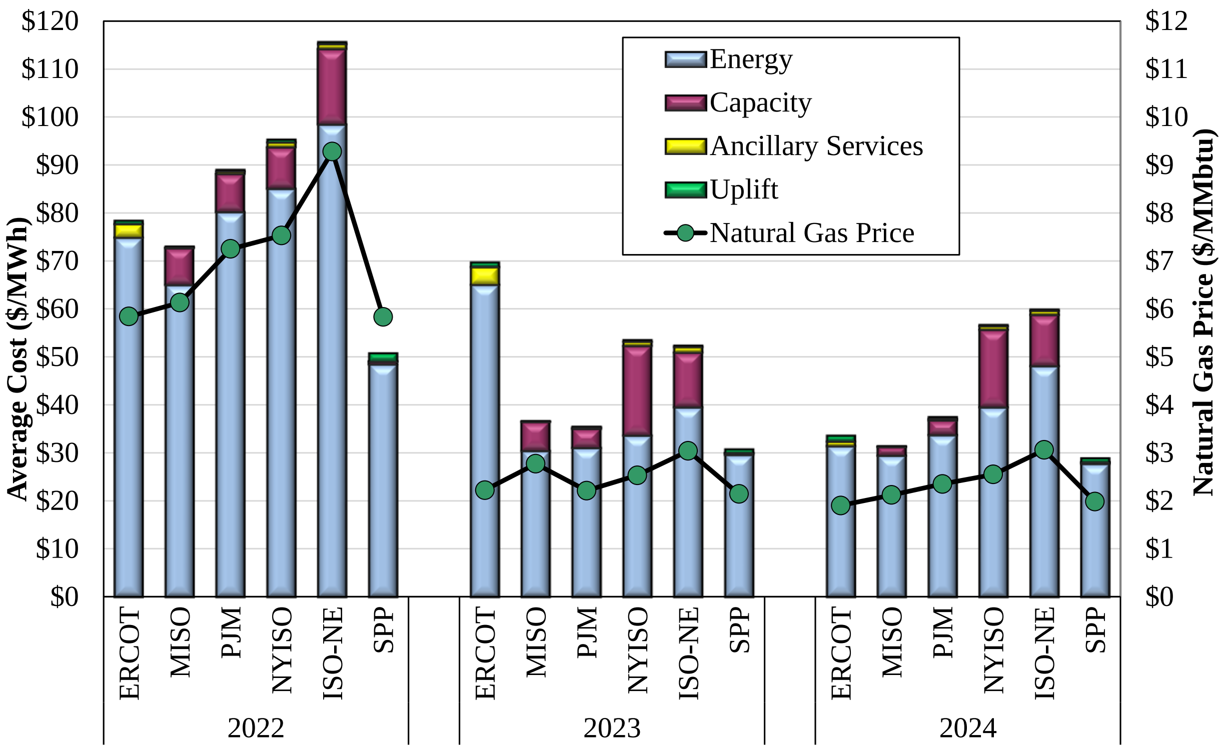
- The all-in price fell 14 percent in 2024 to an average of $31 per MWh.

2 The non-energy costs are shown on a per MWh basis by dividing these annual costs by real-time load.

- Energy prices fell 3 percent as natural gas prices decreased 8 percent.
- Shortage pricing increased 177 percent from 2023. The market cleared in shortage in 34 intervals, up from 18 intervals in 2023.
- The ancillary services component contributed just $0.13 per MWh.
- The capacity component of the all-in price fell 70 percent from 2023 because January through May 2023 reflected the capacity shortage in the Midwest in the annual 2022-2023 PRA. This shortage pricing did not occur in the subsequent PRAs.
- In the 2024-2025 PRA, Zone 5 cleared at CONE during the fall and spring seasons.
- The uplift component of the all-in price increased 1 percent to $0.04 per MWh. This uplift component is very low relative to pre-2023 levels due to improvements in MISO's commitment practices and low gas prices in 2024.[3]

Natural gas prices continued to be a primary driver of energy prices. This is expected as fuel costs are the majority of most suppliers' marginal production costs. Competition produces strong incentives for suppliers to offer at their marginal costs so fuel price changes will cause comparable offer price changes. Figure 2 shows all-in prices in the Eastern RTOs and ERCOT.

Figure 2: Cross Market All-In Price Comparison
2022–2024

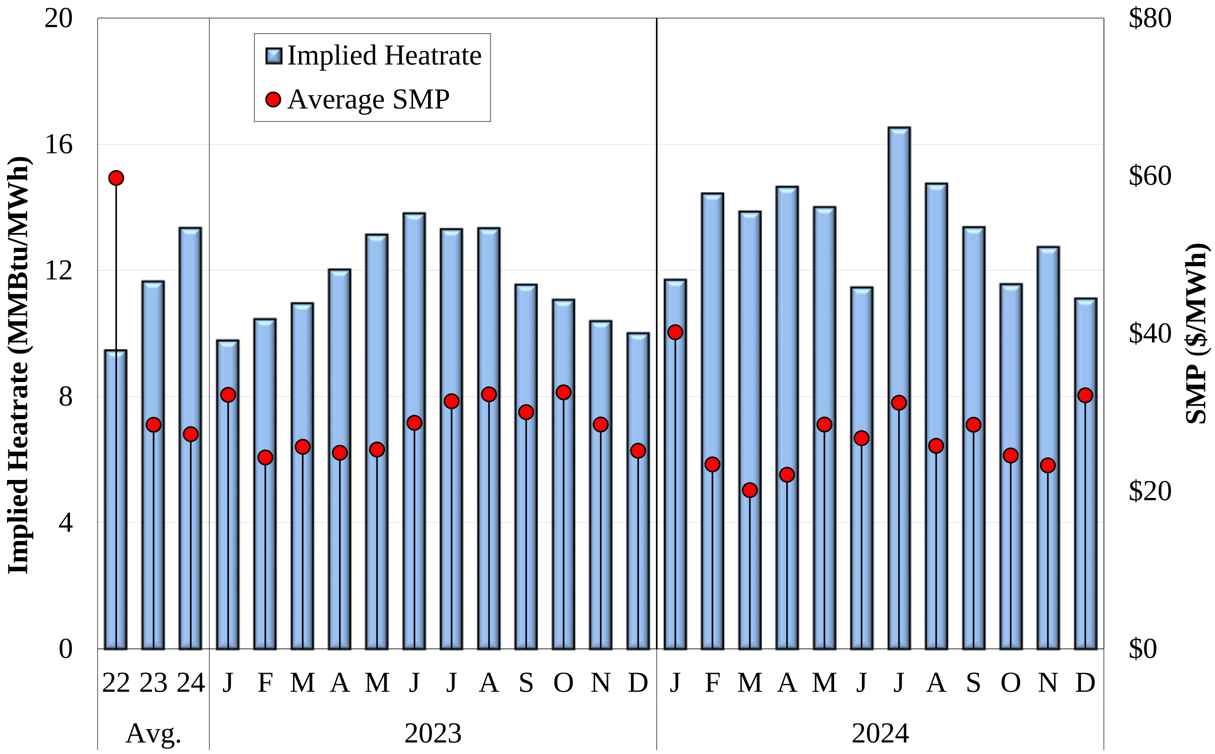


3 Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs, and Price Volatility Make-Whole Payments (PVMWPs).

Each of these RTO markets has converged to similar market designs, including nodal energy markets, operating reserves and regulation markets, and capacity markets (with the exception of ERCOT and SPP). However, the details of the market rules can vary substantially. The market prices and costs in different RTOs can be affected by the types and vintages of the generation, the input fuel prices and availability, and differences in the transmission network capability.

In Figure 2, MISO has exhibited among the lowest all-in prices because of its low natural gas prices and relatively weak shortage pricing. In 2024, MISO filed to improve its shortage pricing by increasing the Value of Lost Load and reforming its Operating Reserve Demand Curve. ERCOT lacks a capacity market entirely but has much stronger shortage pricing. ISO New England's relatively high energy prices are caused by higher gas prices that reflect pipeline constraints. Energy and capacity prices in NYISO have been rising in recent years as 800 MW of peaking resources have retired because of air permit limits. To estimate the effects on prices of factors other than fuel costs, we calculate an "implied marginal heat rate". This is calculated by dividing the real-time energy price by the natural gas price. Figure 3 shows the monthly and annual average implied marginal heat rates.[4]

Figure 3: Implied Marginal Heat Rate
2023–2024



The implied marginal heat rate increased 15 percent from 2023 to 2024 because of a shift in the marginal resources to serve load. Most of the other differences in system marginal prices were

4 See Section II.A of the Appendix for a detailed explanation of this metric.

caused by changes in fuel prices. In the future, implied heat rates are likely to become less predictable as the generating fleet transitions.

B. Fuel Prices and Energy Production

MISO's resource mix continued to evolve in 2024. MISO lost 2 GW of Unforced Capacity (UCAP) from retirements and suspensions and added 2 GW of new resources. Almost all these additions are from solar resources that came online in 2024. New solar resources in MISO receive a 50 percent capacity accreditation for summer months and 5 percent for winter months, so the additions are over 5 GW on a nameplate basis. The additions also include 150 MW in electric storage resources (ESR).

Table 1 below summarizes the share of unforced capacity, energy output, and how frequently different types of resources were marginal in setting system-wide marginal energy prices (SMP) and locational marginal energy prices (LMP) in 2023 and 2024.

Table 1: Capacity, Energy Output, and Price-Setting by Fuel Type

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2023	2024	2023	2024	2023	2024	2023	2024	2023	2024
Nuclear	11,058	10,988	8%	8%	14%	14%	0%	0%	0%	0%
Coal	39,959	37,417	30%	28%	28%	26%	36%	36%	79%	77%
Natural Gas	64,588	63,636	49%	48%	39%	39%	63%	63%	94%	91%
Oil	1,476	1,436	1%	1%	0%	0%	0%	0%	1%	0%
Hydro	4,059	3,783	3%	3%	1%	1%	1%	1%	2%	2%
Wind	9,349	11,362	7%	9%	15%	15%	0%	0%	59%	64%
Solar	1,362	3,880	1%	3%	1%	2%	0%	0%	8%	10%
Other	674	823	1%	1%	1%	2%	0%	0%	1%	2%
Total	**132,526**	**133,326**								

Energy Output Shares. Although real-time energy prices fell slightly in 2024, the lowest marginal cost resources (coal and nuclear) generally remained profitable because of increases in shortage pricing. The share of energy produced by natural gas resources was constant year over year, despite an 8 percent decrease in gas prices. Wind capacity grew slightly, and its share of energy output remained at 15 percent in 2024. The share of energy produced by solar increased to 2 percent because of the addition of new resources.

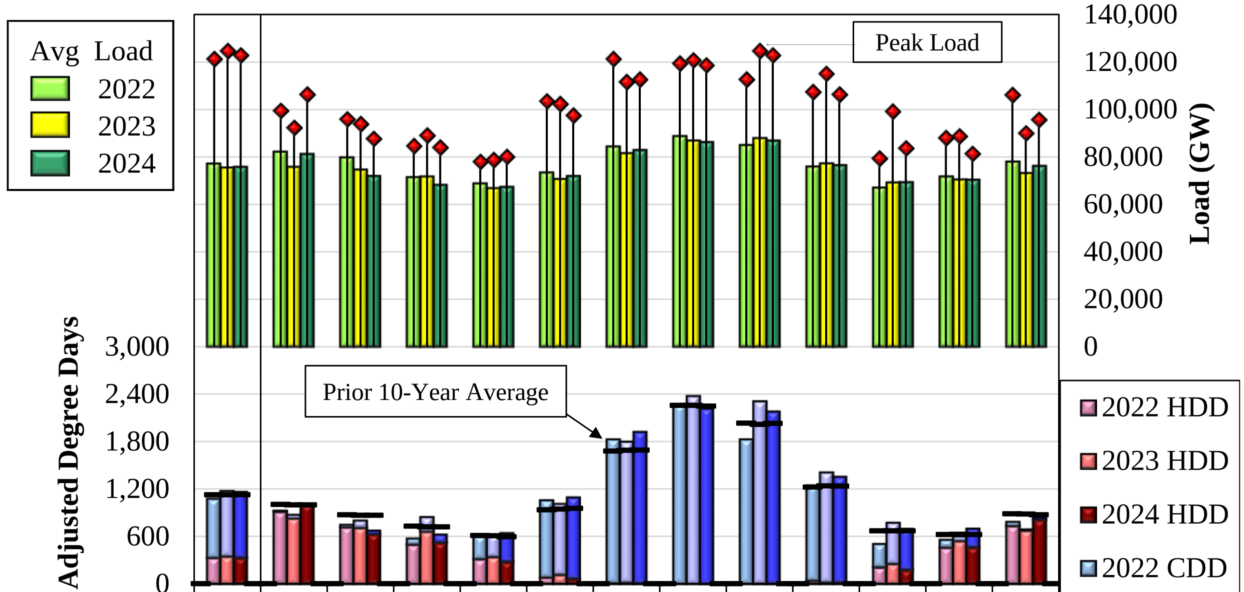
Price-Setting. Most types of resources set system-wide prices for a comparable share of hours in 2024 as in 2023. Although natural gas-fired units produced only 39 percent of the energy in MISO, they set the system-wide energy price in 63 percent of all intervals. In addition, congestion often causes natural gas-fired units to set prices in local areas (91 percent of intervals) when lower-cost units are setting the system-wide price. Wind units set locational prices in 64 percent of all intervals, which is slightly higher than last year because average hourly wind production was higher. Solar units set locational prices in 10 percent of all intervals, which will likely increase substantially in the coming years.

C. Load and Weather Patterns

Long-term load trends are driven by economic and demographic changes in the region, but short-term load patterns are generally determined by weather. Figure 4 indicates the influence of weather by showing the heating and cooling needs together with the monthly average load over the past two years. The top panel shows the monthly average load 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) summed across six representative locations in MISO.[5]

Figure 4: Heating and Cooling Degree Days

2022–2024



% Chg 23-24	Avg	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	0%	7%	-3%	-5%	1%	2%	2%	-1%	-1%	-1%	0%	0%	4%
Degree Days	-1%	14%	-16%	-26%	3%	8%	7%	-7%	-6%	-4%	-10%	16%	22%

In 2024, the system average load was flat from the prior year, while the number of degree days fell 1 percent from 2023. MISO's annual peak load of 122 GW occurred on August 26, as hotter than normal footprint-wide temperatures led to high cooling demand. The annual peak load was in line with the 50/50 forecasted peak of 122.6 GW from MISO's *2024 Summer Seasonal Assessment.* We discuss operational challenges that occurred during extreme weather events throughout the year in detail in subsection E below.

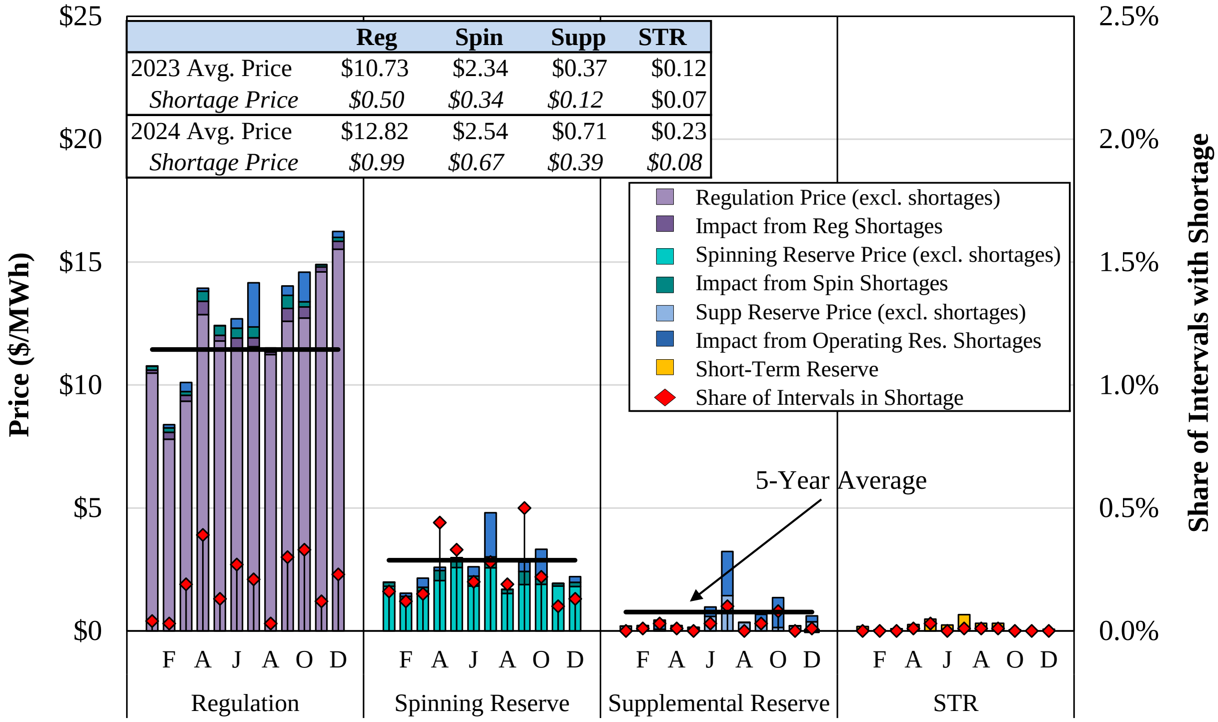
5 HDDs and CDDs are defined using aggregate daily temperatures relative to a base temperature (65°F). To normalize the load impacts of HDDs and CDDs, we inflate CDDs by 6.07 (based on a regression analysis).

D. Ancillary Services Markets

Since their inception in 2009, co-optimized ancillary services markets have produced significant benefits, leading to improved flexibility and lower costs of satisfying the system's reliability needs. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions. For each product, Figure 5 shows monthly average real-time prices, the contribution of shortage pricing to each product's price and the share of intervals in shortage. The figure shows the 5-year average price of the reserve products, except STR, which was implemented in late 2021.

Figure 5: Real-Time ASM Prices and Shortage Frequency

2024



	Reg	Spin	Supp	STR
2023 Avg. Price	$10.73	$2.34	$0.37	$0.12
Shortage Price	*$0.50*	*$0.34*	*$0.12*	$0.07
2024 Avg. Price	$12.82	$2.54	$0.71	$0.23
Shortage Price	*$0.99*	*$0.67*	*$0.39*	*$0.08*

Supplemental (offline) reserves only meet the market-wide Contingency Reserve requirement (i.e., 10-minute operating reserves). Spinning reserves can satisfy both the Contingency Reserve and the spinning reserve requirements, so the spinning reserve price will always be equal to or higher than the Contingency Reserve price. Similarly, regulation prices will include components associated with spinning reserve and Contingency Reserve shortages.[6] Likewise, energy prices include all ASM shortage values plus the marginal cost of producing energy. MISO's demand curves specify the value of each of its reserve products. When the market is short of a reserve product, the demand curve for the product will set its market clearing price and affect the prices

6 The demand curve for regulation, which is indexed to natural gas prices, averaged $139.76 per MWh, up from $110.28 per MWh in 2023. The spinning reserve penalty price was unchanged at $65 per MWh (for shortages < 10% of the reserve requirement) and $98 per MWh (for shortages > 10%).

of higher-valued reserves and energy through the co-optimized market clearing. Figure 5 shows that the average clearing prices rose for all reserve products in 2024, despite lower natural gas prices, likely because of increases in shortage pricing in 2024.

Regulation prices increased in the second half of the year after MISO raised the previous floor requirement from 400 MW to 600 MW. This increase in June 2024 came after observing a decrease in CPS1 ("Control Performance Standard 1"), with regulation being the only tool to improve this score.[7]

Short-Term Reserves. Based on our recommendation, MISO implemented a 30-minute reserve product (short-term reserves or "STR") in December 2021. We had recommended the requirements be applied locally to zones with VLR requirements, but they are currently only applied to MISO and its two subregions. STR prices averaged close to zero in the day-ahead and real-time markets (under $1 per MWh) in 2024. MISO began adjusting STR requirements in 2024 to account for uncertainty, increasing the requirements to address the risk of unexpected changes in supply or demand on high-uncertainty days. This change is beneficial because higher requirements can lead to higher STR prices (including shortage pricing) that incent good generator performance and increased net imports that ultimately mitigate the uncertainty.

MISO enforces STR requirements in its two subregions by enforcing reserve procurement enhancement (RPE) constraints over the Regional Directional Transfer (RDT) constraint. The RPE binds when headroom on the RDT plus the available STR in the importing subregion is 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). While this change has improved the performance of STR, we continue to recommend MISO expand the RPE constraints to enforce STR requirements in local reserve zones with VLR needs to provide efficient incentives for suppliers to invest in fast-start units that can satisfy the VLR requirements. This would also reduce the need to make out-of-market commitments of high-cost units in those areas.

In 2024, we identified a pricing inefficiency that occurs related to local STR clearing when the RDT binds in the South-to-North direction because of the combined effects of the RPE and the RDT constraint. Prices throughout the Midwest reflect the shadow prices of the RDT and RPE constraints when both are in violation, raising prices by up to $700 per MWh ($500 per MWh for the RDT violation plus $200 per MWh for the RPE). Adding $200 per MWh for RPE violations when the RDT is in violation is inefficient. Overpricing RDT violations by $200 per MWh when the constraint is in small violation is costly and can cause the dispatch to violate local constraints. Hence, we recommend MISO adjust the RDT demand curve so the total price impact of simultaneous binding of the RDT and RPE does not exceed $500 per MWh.

[7] Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100% by NERC Standard BAL-001. MISO publishes the CPS1 performance every month at the Monthly Operations Report. https://www.misoenergy.org/markets-and-operations/markets-and-operations/

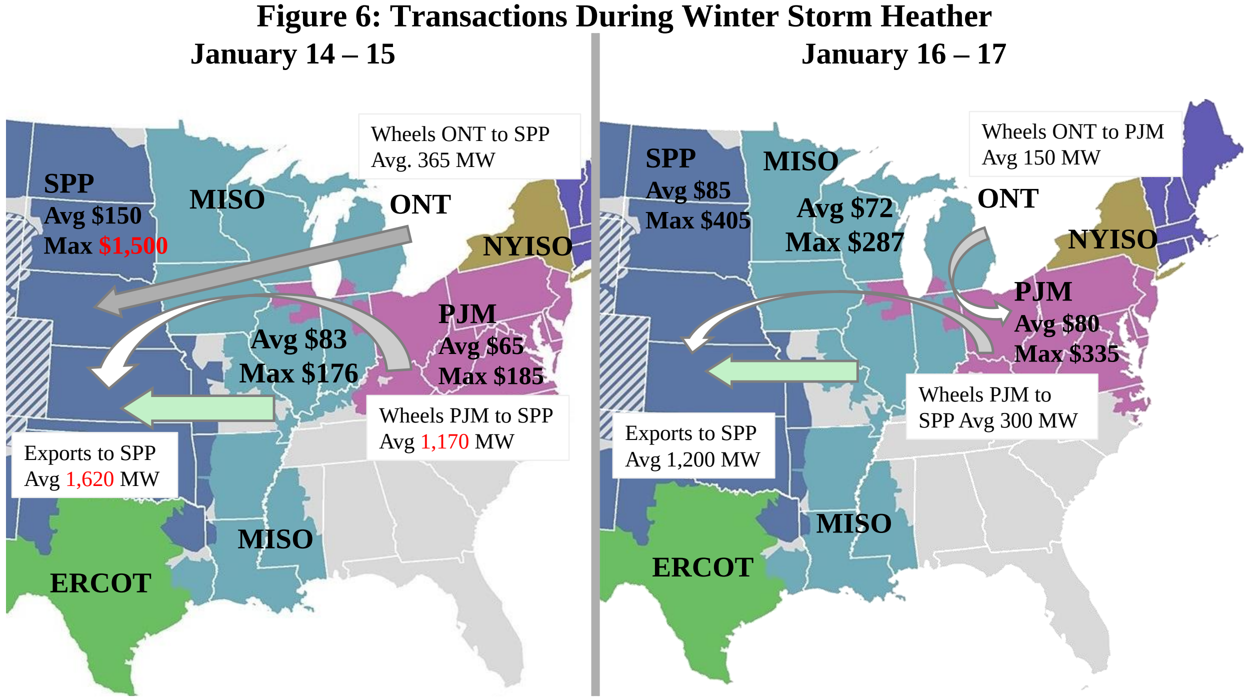
E. Weather Events and Market Outcomes

MISO experienced three challenging weather events in 2024. In January, Winter Storm Heather created widespread impacts and challenging operating conditions. In July, Hurricane Beryl caused extensive damage and associated operational issues in the South and MISO experienced operational issues in the Midwest on the same day. In August, the system reached its annual peak demand during an extended period of hot weather requiring Conservative Operations.

Winter Storm Heather

In mid-January, a series of impactful storms known collectively as Winter Storm Heather affected the MISO region. MISO effectively managed the system without recourse to Emergency operations. A polar vortex generated record low temperatures in most of SPP and MISO, and later Southern Company and TVA, over the Martin Luther King holiday weekend. The low temperatures affected both supply and demand, as South demand reached a new winter record high of 32.6 GW and fuel supply issues and cold temperature derates and outages caused simultaneous operating stresses. Multiple pipelines signaled the likelihood of restrictions to manage the competing gas demands for power and heating. Limited gas trading over the holiday weekend increased the challenges by increasing suppliers' risk related to fuel supply availability and led multiple units to offer increased notification times. Gas prices were volatile and required the IMM to actively update generator reference levels to avoid inappropriate market power mitigation. Wind output was high throughout the event, setting a new record at almost 26 GW. Figure 6 shows interchange with neighboring systems that were also affected by the storm.

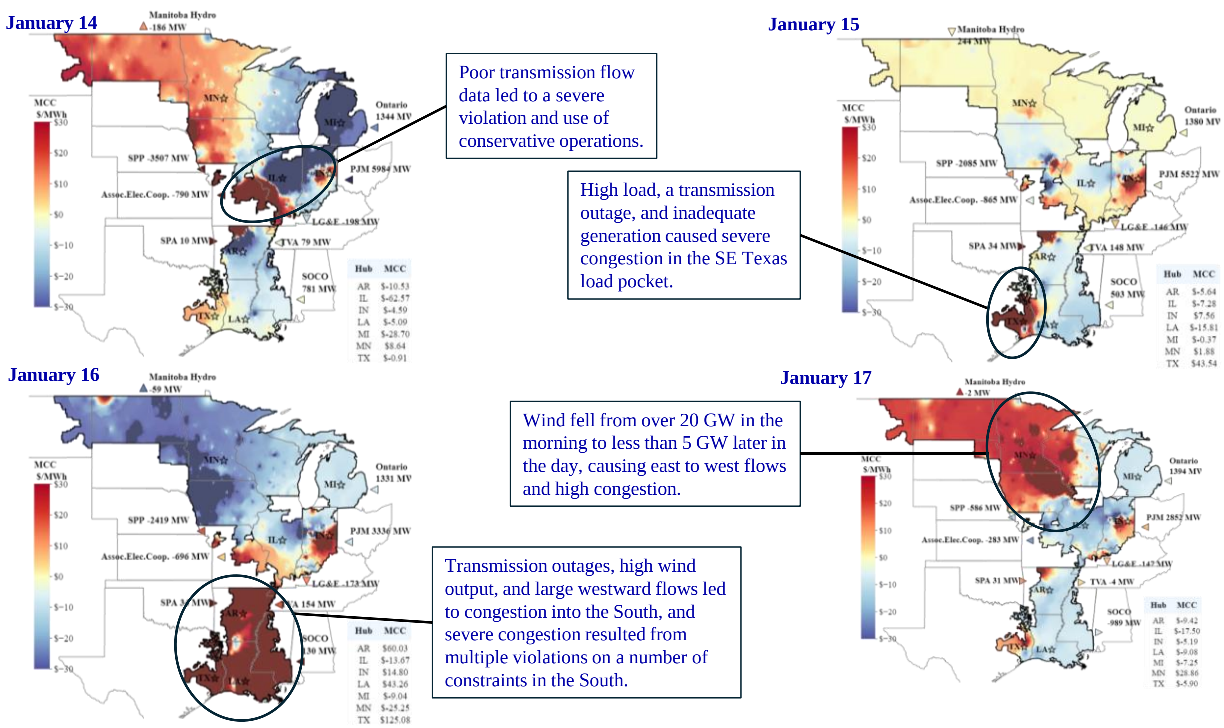
Figure 6: Transactions During Winter Storm Heather



As in prior storms, wheels and external transactions were unusually large. MISO supported extensive exports and wheels from PJM and Canada to SPP in the first two days of the storm. The total average transfers to SPP on these days exceeded 3.2 GW, which was similar to the flows during Winter Storm Uri in 2021. However, generators seemed better prepared for the cold temperatures, so forced outages were lower and congestion related to the wheels and exports were easier to manage than during Winter Storms Uri in 2021 and Elliott in 2022. As the storm moved east, transaction patterns changed on January 16 and 17. Imports from PJM and wheels to SPP dropped sharply. Ontario began wheeling power to PJM, and MISO began exporting up to 2,000 MW to Southern Co. while maintaining roughly 1,200 MW of exports to SPP. In past storms, large power flows through and out of MISO generated severe congestion.

Figure 7 illustrates the congestion patterns during the event by showing heat maps of the average daily congestion component of prices. Higher congestion components are represented by warmer colors and lower congestion components are represented by cooler colors. The intensity of the colors indicates the relative magnitude of congestion. Generally, power flows across the system from the cooler colors towards the warmer colors.

Figure 7: Daily Average Congestion During Winter Storm Heather



On January 14, poor information on transmission flows provided by a MISO Transmission Owner led to a large transmission violation – post-contingent flows were 150 percent of the rating. This raises substantial concerns regarding the information some participants provide to MISO, which can impact reliability.

On January 15 and 16, MISO effectively ran out of generation in the Southeast Texas (SETEX) load pocket, resulting in severe congestion in that area. This was mitigated after a dually-connected unit switched from ERCOT to MISO early on January 16. MISO was fortunate because this resource has no obligation to MISO, which underscores our concern that MISO's capacity zones do not reflect electrical load pockets with discrete needs, such as the SETEX load pocket. This prevents the market from procuring needed resources and sending efficient investment signals.

On January 17 as the storm traveled eastward towards PJM, wind in MISO fell from more than 20 GW to under 5 GW, which caused east-to-west flows and high congestion in the North Region. Overall, MISO was able to effectively manage the changing congestion patterns.

In addition to congestion, winter events create substantial uncertainty regarding supply adequacy. Two factors led to the commitment of more resources through the market and less need to commit resources outside of the market:

- MISO increased the STR requirements by 1000 to 2000 MW (25 to 50 percent) to manage the uncertainty.
- High levels of virtual load cleared in the day-ahead market, likely because of the price expectations based on the outcomes during Winter Storms Uri and Elliot. Because extreme real-time prices did not materialize, virtual demand lost $31 million, compared to profits of $28 million and $97 million in Winter Storms Uri and Elliott, respectively.

These factors reduced the need for MISO to make out-of-market commitments. MISO also exercised good judgment in avoiding unnecessary commitments and deferring those that were needed as long as possible based on resources' offered lead times. This ultimately lowered RSG to $5 million for the event, compared to almost $90 million in Winter Storm Uri and $15 million in Winter Storm Elliott.

Finally, the event highlighted the importance of fixing existing flaws in the calculation of the interface prices at the border with SPP and PJM that distort the incentives to schedule imports and exports efficiently. At the SPP interface, MISO includes external market-to-market congestion in its interface price that is fully priced in SPP's interface price, thus "double pricing" the congestion. During this event, this incentive error produced price distortions at the SPP interface ranging from -$100 per MWh (under-incenting exports to SPP) to nearly $50 per MWh (over-incenting exports to SPP).

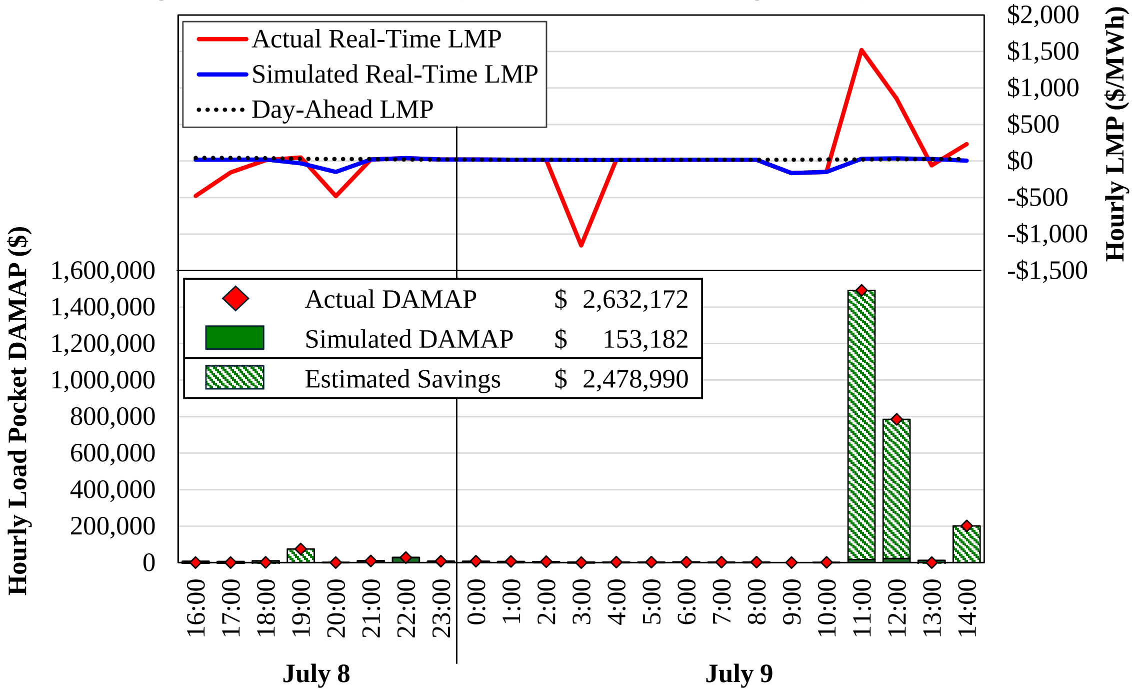
Hurricane Beryl

Hurricane Beryl substantially affected Texas and Louisiana on July 8 and 9, causing extensive transmission outages and ultimately an "islanding" event. MISO managed the reliability of the system well during this event. However, prices were volatile and inefficient in the Southeast Texas load pocket (SETEX). The hurricane caused over 70 transmission outages on July 8, reducing the connection to SETEX to one line and causing load in the pocket to drop to roughly 400 MW. Late on July 8, the single line was lost, and the pocket was islanded.

MISO declared a Restoration Event until the pocket was reconnected around 4 am on July 9. To protect the pocket, MISO had modeled the constraint for the remaining line with a limit close to zero. Because most resources in the pocket were being manually dispatched by MISO and Entergy, the market dispatch could not manage the constraint, resulting in constraint violations. These violations caused prices in the load pocket to average $1500 per MWh in 2 hours and -$1500 per MWh in a different hour. Units that MISO turned off or dispatched down in the load pocket received over $3 million in DAMAP, which was allocated throughout MISO.

Because the constraint was not a true constraint and the market was not managing it, the prices and costs associated with it were not efficient. To model these effects, we simulated the market outcomes assuming a low transmission constraint demand curve (TCDC) for the single line in question. Figure 8 shows the simulation results for July 8 and 9. The red line shows the actual prices in the load pocket, while the blue line shows the simulated prices. The bottom of the figure shows the actual DAMAP paid in the load pocket to units turned off. The hatched bar shows the estimated DAMAP savings had MISO modeled the constraint with a lower TCDC.

Figure 8: Hurricane Beryl: SE Texas Islanding on July 8-9, 2024



The simulation shows that prices would have reflected the true marginal production costs of the generation serving the pocket and that make-whole payments would have fallen by more than 75 percent. We find that the volatile pricing in SETEX during the event was inefficient and led to unwarranted uplift costs. Our evaluation indicates that constraints modified for reliability purposes that are not secured by the market should be excluded from the market pricing.

In addition, given the amount of load that was forced off by transmission damage, this should have qualified as a Forced Off Asset (FOA) Event, causing real-time prices to be set equal to day-ahead prices. This event did not qualify because the FOA Revenue Inadequacy criteria is defined too narrowly. Hence, we recommend MISO limit the dead bus criteria defining an FOA to load buses, as well as include both Revenue Inadequacy and Price Volatility Make-Whole Payments as the financial criteria for FOA declarations.

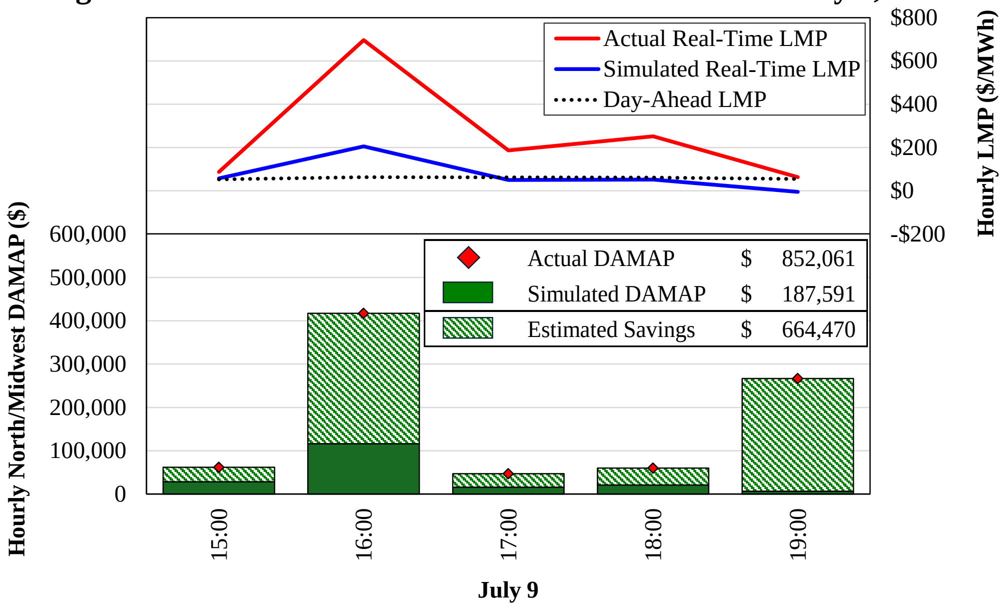
Events in MISO Midwest during Hurricane Beryl

There were also operational challenges in MISO Midwest on the same day. After a 540 MW generator trip at 2:30 pm on July 9 in the Midwest, MISO's look-ahead commitment model (LAC) began recommending operators commit replacement resources. Operators did not make these commitments, causing power flows from the South to the Midwest that severely bound the RDT constraint, resulting in the following cascading effects:

- Prices rose throughout MISO Midwest by up to $240 per MWh;
- Most generators were economic to dispatch up to manage the RDT, even some that needed to be dispatched down to manage constraints, which led 13 constraints to be violated at the same time. To manage the violated constraints, MISO:
- Called transmission line load relief procedures that caused a 790 MW loss in imports, exacerbating the capacity shortage conditions in the Midwest.
- Manually reduced the output of certain units in the Midwest, causing another 1300 MW loss of capacity. This led to $852,000 in DAMAP costs paid to these units.

We simulated of the events of July 9 to show the effects of having responded to the LAC recommendations rather than taking the actions described above, which are shown in Figure 9.

Figure 9: IMM Simulation of MISO Commitments on July 9, 2024



The top panel shows the actual prices and simulated prices at a key location in the Midwest, while the bottom panel indicates the amount of DAMAP that resulted from the operators' actions that would have been saved had operators committed the recommended units. This figure shows the value of more consistently responding to the LAC recommendations, particularly during the type of tight conditions that occurred on July 9. Hence, we recommend MISO implement identified improvements in the LAC model to increase confidence and promote acceptance of its recommendations by operators.

Hot Weather Event August 23rd-27th

MISO's annual peak demand was reached on August 26 during a hot weather event from August 23-27. This annual peak in 2024 was lower than in 2023, but it would have been slightly higher but for voluntary demand response. During this event, MISO issued emergency declarations that allow it to access additional supply and demand response that increase its reserve margin. However, because emergency declarations increase the available margin outside of the energy market, they tend to distort market outcomes. Hence, MISO should only make the declarations needed to access the quantity of emergency supply necessary to address the shortages.

MISO issued alerts in this event that escalated to a Maximum Generation Warning from 1 pm to 8 pm on August 26, triggering Tier 0 and Tier 1 emergency pricing. Tier 0 and Tier 1 pricing allows 4-hour GTs and emergency MW to set prices in ELMP, respectively. MISO's Tier 0 pricing increased prices by an average of $60 per MWh during the Warning, sustaining PJM imports even though prices in PJM were also high, which is shown in Figure 10 below.

Figure 10: Pricing and Imports from PJM August 26, 2024

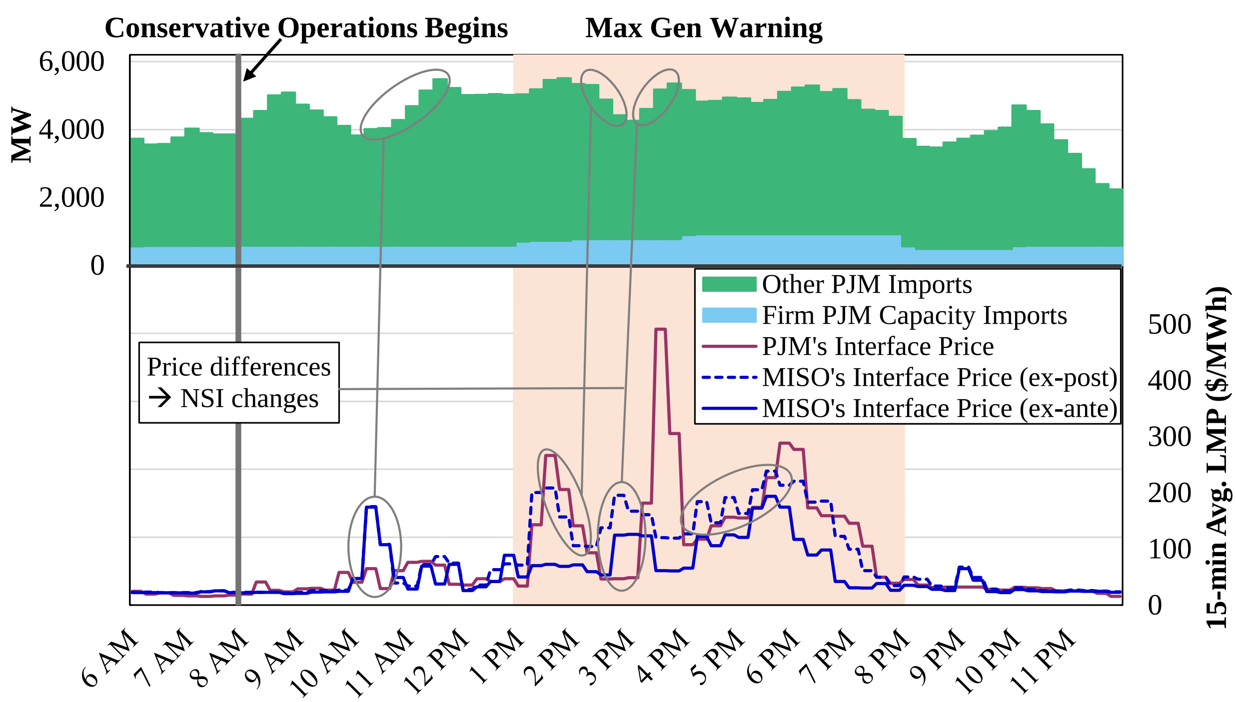


Figure 10 shows net imports from PJM in the top panel, separating the firm imports in the blue shaded area from the non-firm imports in the green shaded area. In the bottom panel, we show the prices for PJM's interface for MISO, as well as MISO's ex ante and ex post prices for PJM. The blue dotted line representing the ex-post MISO interface price for PJM is frequently much higher than the ex-ante price because of MISO's emergency pricing.

The emergency pricing during this event helped sustained imports when PJM's prices were also high, illustrating the benefit of efficient emergency pricing in reducing MISO's need to rely on emergency supply or DR. Overall, we found that MISO made appropriate emergency declarations during the event, which led to relatively efficient outcomes during the event.

IMM Conclusions and Recommendations for Future Extreme Weather Emergencies

Lessons learned from hot weather and emergency events indicate opportunities to improve and clarify the emergency procedures. Some lessons learned from past and current events include:

1.) *Timing is key* – actions should only be taken when needed, given lead-time considerations. The lowest level event should be called based on the quantity of MWs needed.

2.) *A zero reserve margin ("headroom") should be the target* – Out-of-market actions should only be implemented to mitigate negative headroom. Seeking positive headroom to address uncertainty undermines the market and distorts prices.

3.) *Rely on STR to address uncertainty* – If uncertainties cause negative headroom, MISO can utilize up to 2 GW of STR to maintain its reserves. Any STR shortage will raise prices and provide strong incentives to schedule net imports that will address the shortage.

4.) *Information is essential* – providing more information to participants leading up to events allows them to be better prepared and schedule NSI. This could include forecasted demand, available resources, NSI, and prices from long LAC cases.

5.) *Clear procedures are important* – Many of the operator actions before and during emergencies are not clearly described in procedures, compelling operators to make difficult choices under stressful conditions. Clarifying the criteria for taking various emergency actions would lead to improved market performance and reliability.

The application of some of these lessons led to much better performance by MISO during the August 23-27 hot weather event. For example, operators prudently committed resources and declared appropriate emergency levels. MISO also increased STR requirements to dynamically account for risk and uncertainty, which is a much more efficient means to address uncertainty through the market rather than committing resources outside of the market. Nonetheless, some resources were committed that were not needed, indicating opportunities for further process improvements. MISO continues to actively work with us on these improvements.

III. FUTURE MARKET NEEDS

The MISO system is changing rapidly as its resource fleet transitions and new technologies enter the market, requiring MISO to adapt to new operational and planning needs. In addition, the long period of low load growth appears to be ending and MISO now projects a growth rate of one to two percent per year over the next 20 years, which result in steadily increasing capacity needs.[8]

MISO's markets are well suited to facilitate both the rapid penetration of renewables and the sudden load growth, and we expect there will be no need for fundamental market changes. However, a number of key improvements will be critical as MISO proceeds through these changes, some of which are currently underway. In this Section, we discuss the implications of the changes in MISO's load growth and resource portfolio, as well as the key issues in this section that MISO will be facing in the coming decades. We then identify the key market and non-market improvements that will allow MISO to successfully navigate this transition.

A. Future Demand in MISO

While the focus in recent years has been on the clean energy transition underway in MISO on the supply side, significant changes are now anticipated on the demand side. MISO has evaluated significant electrification of the transportation sector with the widespread adoption of electric vehicles (EVs). At the same time, the entry of large data centers and other industrial loads has accelerated. These changes will substantially affect load profiles and congestion patterns.

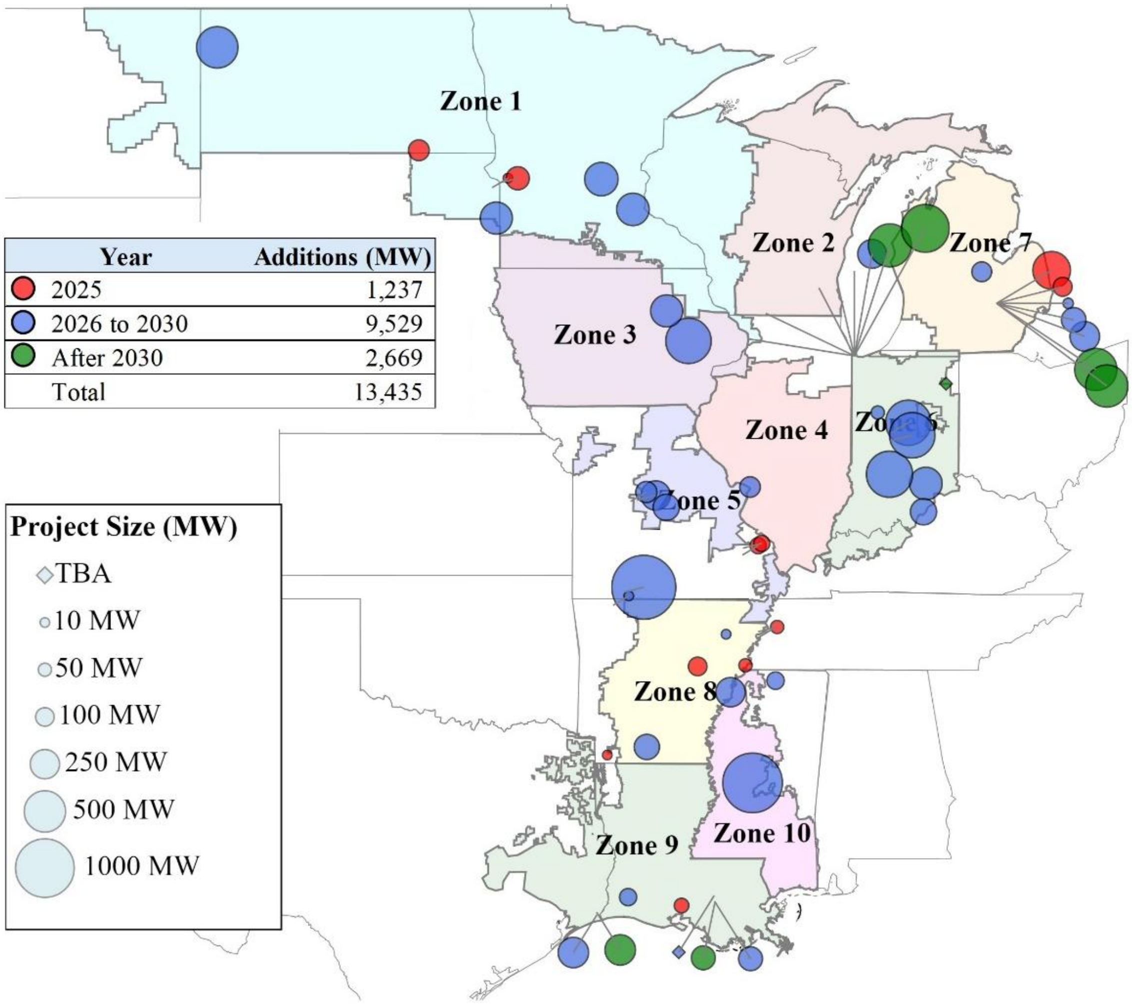
MISO's expected load growth is now significantly higher than even last year's forecast, given the substantial penetration of new data centers supporting AI and cryptocurrency mining, as well as increased electric vehicle demand. In MISO's 2023 long-term load forecast, anticipated load growth rate on a compound Annual Growth Rate (CAGR) basis, to range from 0.4 to 1.1 percent. The MISO 2024 forecast ranges from 1.0 to 2.0 percent, greatly raising expected load growth:

- The midpoint of the 2024 forecast would increase the currently prevailing Summer Planning Reserve Margin Requirement of 136 GW to 157 GW (21 GW) over ten years.
- The midpoint of the 2023 forecast produces an increase of only 11 GW.

Figure 11 shows the large load additions expected over the next few years. The information is based on public announcements and projects from MISO Subregional Planning Meetings. These large loads, which are additional to the demand growth due to electric vehicles and heating, represent almost 11 GW of additional demand for the next 5 years. Data centers lead the list of large loads, followed by industrial sectors, including steel, oil refineries, semiconductors, mining, and other industries. Most of these loads are suitable for providing demand response services, which should drive the growth in demand response resources discussed in Section IX.

8 MISO Long-Term Load Forecast whitepaper, December 2024.

Figure 11: Expected Load Additions in MISO



Improvements in MISO's capacity market should help facilitate that investment needed to serve these load reliably, but MISO may confront significant transmission issues. RTOs generally assume that load growth can be served on a firm basis, but large loads siting at weak locations may require transmission upgrades. It may become important to develop the processes necessary to identify needed upgrades and serve them on a non-firm basis pending the upgrades.

B. MISO's Future Supply Portfolio

Aside from load growth, future market needs are also determined by the resource mix. In recent years, wind and solar penetration in MISO has consistently increased as baseload coal resources have retired. To date, MISO has effectively managed the operational challenges of simultaneously integrating intermittent resources while losing conventional dispatchable resources, although these challenges have increased, and this trend is expected to continue.

MISO has more than 1900 active projects in the interconnection queue, totaling over 350 GW. Almost half of these are solar projects, 12 percent are wind projects, 15 percent are hybrid projects, and 17 percent are battery storage.[9] Distributed energy resources may also grow and play a more substantial role in the future. MISO has emphasized the importance of the attributes that dispatchable resources provide and participants have responded by announcing the addition of more than 30 GW of new gas resources over the next 20 years.

Figure 12 shows MISO's anticipated mix of resources based on its prior and updated "Future 2" Scenarios used for its planning studies, which are intermediate scenarios between Futures 1 and 3 that show a slower and faster clean energy transition, respectively.[10] Figure 12 shows wind and solar resources planned by the states in solid bars, and the wind and solar projected by MISO's capacity expansion model in the striped bars. Flex resources are un-named resources MISO added to Future 2A after it was initially produced to meet its energy adequacy needs.

Figure 12: Anticipated Resource Mix: 2032 and 2042

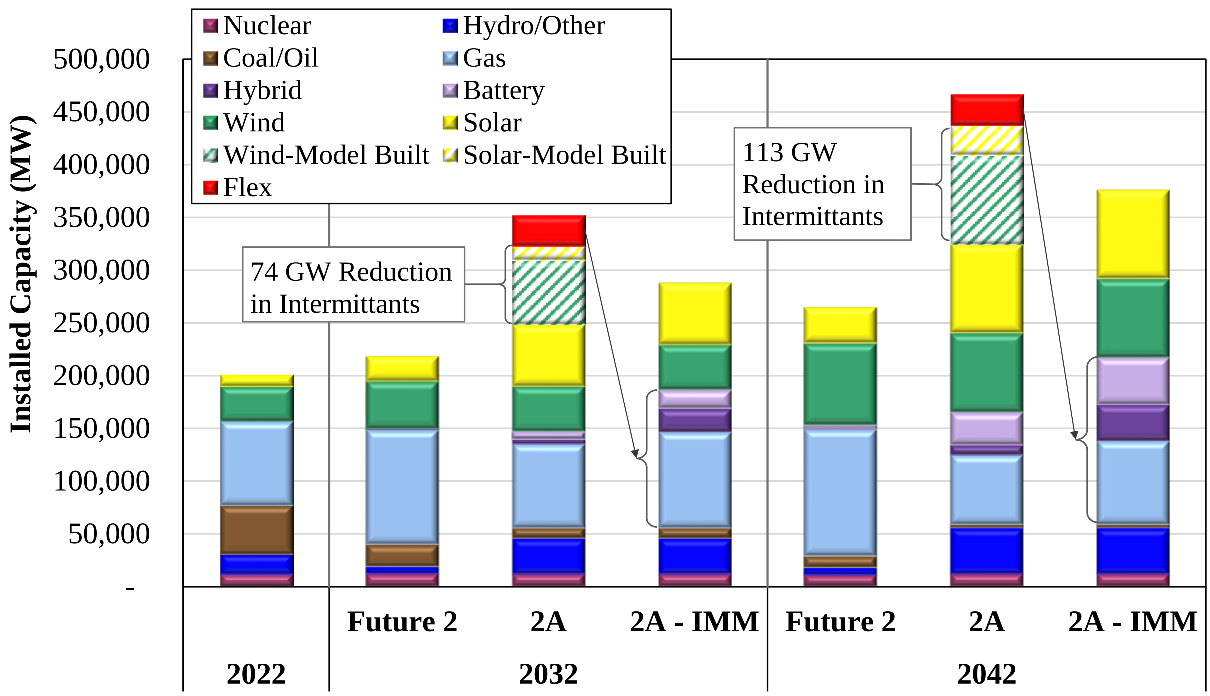


Figure 12 shows that MISO's expectations changed considerably over the two years from the publication of Future 2 (2021) and Future 2A (2023). The changes are critical because they have significantly increased MISO's perceived need for transmission. However, we find that Future 2A is unrealistic and is not suitable as a basis for MISO planning for the following reasons:

- The large reductions in gas-fired generation are unrealistic given the system's need for the attributes that these resources provide, and the billions of dollars of new gas resources that have been announced recently and those in the interconnection queue.

9 See: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/. Data downloaded March 3, 2025.

10 See: MISO Futures Report. Future 2 was published 2021 and Future 2A in 2023.

- The substantial increase in coal retirements because of more aggressive age-based retirement assumption (36 years) is questionable for resources in states with no announced decarbonization plans where many of these resources are located.
- Much faster growth of intermittent solar and wind resources is due to the announced plans of states and utilities, but almost half is simply projected by MISO's capacity expansion model—the Electric Generation Expansion Analysis System (EGEAS). This model grossly overestimated investment in intermittent renewable resources because it:
  - Fails to recognize the falling reliability value of intermittent resources;
  - Does not value the attributes and associated market revenues that will incent investment in storage, hybrid renewable, and new gas resources.

Addressing the issues caused by the EGEAS model to produce a more reasonable capacity expansion forecast reveals a very different future, which is illustrated by our alternative case to Future 2A (i.e., the IMM 2A case). This case accepts MISO's assumptions on "committed resources", which includes almost 160 GW of intermittent resources, but it assumes a more realistic mix of gas resources, hybrid resources, and battery storage will be added to meet MISO's energy and resource adequacy requirements.[11] These resources provide a much higher marginal reliability to the system so they can satisfy MISO's reliability requirements with a smaller amount of this capacity than the assumed intermittent resources. The total capacity levels would fall further than shown if some of the assumed intermittent resources are converted to hybrid configurations or are replaced by dispatchable carbon-free resources, which MISO's new marginal accreditation framework will incent. The much more realistic IMM-modified 2A case:

- Lowers costs by $88 billion compared to MISO's Future 2A;
- Satisfies the States' carbon goals and MISO's energy adequacy needs; and
- Is much more consistent with MISO's market incentives that are based on the attributes needed by the system.

Given the importance of the Futures scenarios for MISO's long-term planning, we recommend MISO address these issues together with the revised view in forecasted load trends in its current process to update the Futures cases, which MISO began in late 2024.

Expansion of Wind and Solar Resources

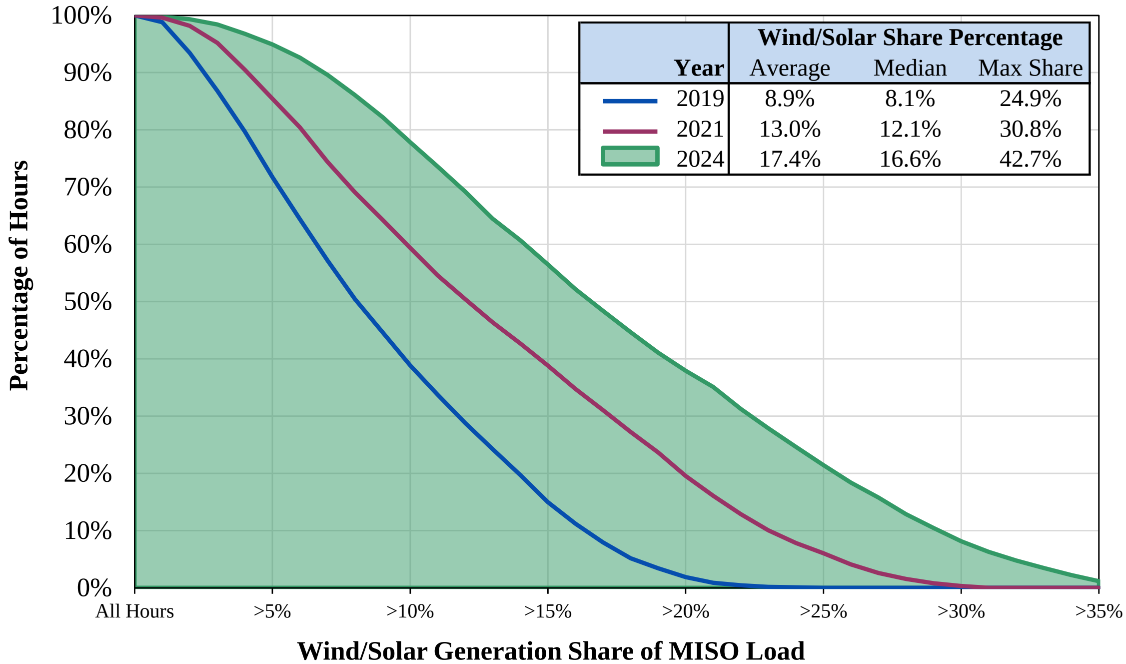
The clean energy transition in MISO began primarily as a large-scale investment in wind resources. Average hourly wind output grew eight percent in 2024 from the prior year to 11.2 GW and supplied 15 percent of all energy in 2024. In recent years, however, solar investment has outpaced wind investment. Average solar output rose by a sizable 128 percent in 2024 to more than 1.6 GW, totaling 2 percent of all energy. Almost all of the solar resources have

11 We replace the accredited capacity from new intermittent resources with gas, hybrid, and battery resources.

entered the MISO market over the past two years. MISO's record solar peak output of 12.6 GW occurred in May 2025.

Wind and solar generation often vary substantially from hour to hour, but solar typically does so in a more predictable pattern. Together, intermittent renewable resources are serving an increasing share of the load in MISO. Figure 13 below shows the cumulative share of MISO's load served by wind and solar, and how this share has changed over the past six years. The x-axis represents the percentage of load served by wind and solar. The y-axis shows the percentage of hours during the year when renewable output exceeded that share of load.

Figure 13: Share of MISO Load Served by Wind and Solar Generation



This figure shows that renewable output as a share of load in MISO grew substantially between 2019 and 2024. Renewable resources served more than 17 percent of the load on average in all hours and served almost 43 percent of the load in the highest-share hour. Given the proposed projects in the interconnection queue, we expect this trend of increasing renewable energy output to continue in the coming years, led by the increased penetration of solar resources. Hence, MISO will need to continue to address the operational challenges associated with the already high penetration of renewable resources on its system, some of which are described below.

Renewable Energy Output Fluctuation. Operational challenges associated with managing renewable generation arise because of substantial uncertainty associated with its output. Much of this uncertainty is associated with errors in forecasting the wind and solar output. These errors tend to arise in hours when wind or solar output changes rapidly. Wind output peaked at more than 25 GW in January 2024 and the high output levels have resulted in high output fluctuations. For example, wind output fell by more than 5 GW over unique 60-minute periods twice in 2024.

Given the operating profile of solar resources, these resources will lead to significant changes in the system's ramping needs that must be satisfied by conventional resources. For example, as solar output falls in the evening in the winter months, load is typically increasing to the second peak load of the day. This can place great stress on the conventional generating fleet to satisfy this ramp demand, particularly if wind output happens to be falling. One metric for measuring the demand on conventional generation is "net load", which is load minus renewable energy output. Figure 14 shows the net load on January 19, 2025, when falling solar and wind output occurred as load was rising in the evening, which is typical in colder months. This curve has been referred to as the "duck curve" because of its shape.

Figure 14: Net Load in MISO on January 19, 2025

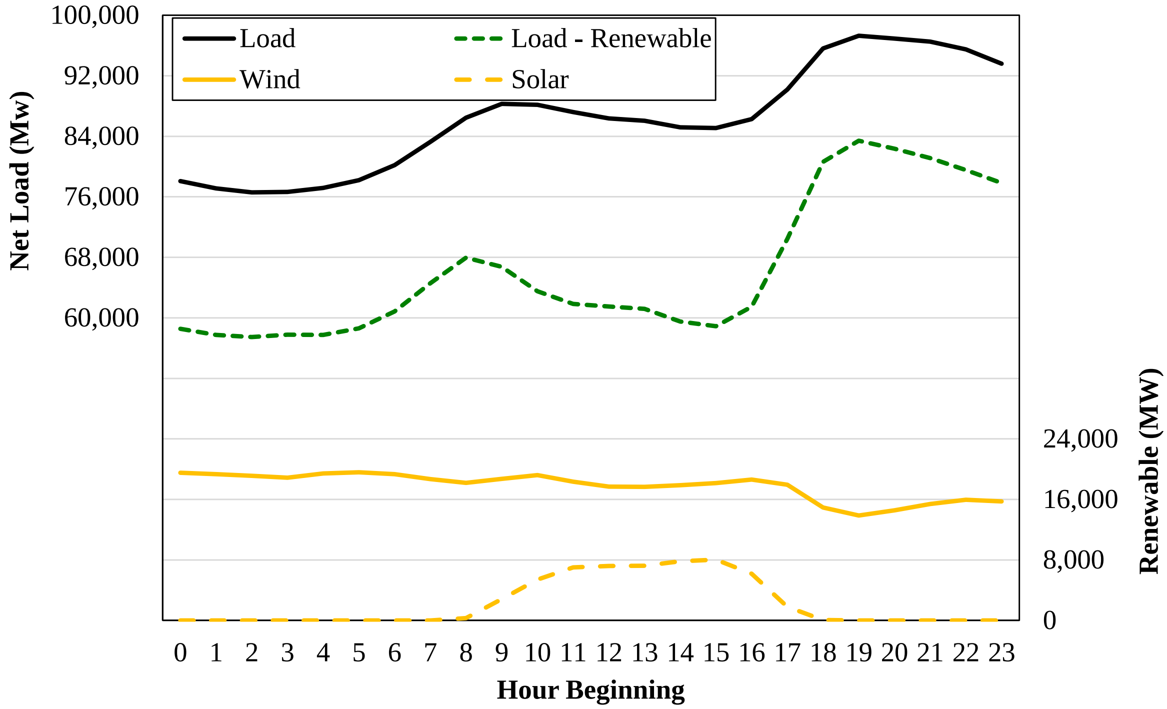


Figure 14 shows that falling wind output occurred as the sun was going down on January 19 that resulted in a ramp demand of almost 24 GW in the evening hours. In this case, MISO had sufficient resources online to manage this event successfully. However, these conditions are likely to grow in frequency and magnitude in the future. In addition, MISO continues to experience periods when intermittent output is close to zero. This underscores the importance of having sufficient dispatchable and flexible resources available to satisfy the system demands when intermittent generation is not available or is ramping down rapidly.

Transmission Congestion Caused by Renewable Resources. In addition to the issues caused by the ouput uncertainty, the concentration of location of many of these resources has created growing network congestion in some periods that can be difficult to manage. This challenge is increased when renewable resources do not follow dispatch instructions. In Section IV.F., renewable resources that are the marginal resource for managing a constraint by curtailing are often economically indifferent between curtailing and losing production tax credits and not curtailing and paying the prevailing LMP that will equal its offer price. To address this concern, we have recommended dispatch deviation penalties based on the congestion component at each resource's location to ensure they have proper incentives to respond to curtailment instructions.

System Support by Renewables. Traditional synchronous generators inherently produce and absorb reactive power, which is critical for voltage regulation across the system. As these generators are displaced by renewables, the system loses a key source of dynamic and steady-state voltage support. While renewable resources and energy storage, inverter-based resources (IBRs), can provide reactive power through their inverters, this capability is often underutilized or unavailable. If renewable resources enter at weak network locations, it can reduce the voltage regulation and stability in these areas. Additionally, some IBRs may trip offline during transient voltage dips, exacerbating the voltage recovery problem. MISO is moving to address these issues by strengthening its generator interconnection procedures to require new renewable resources to provide reactive power capability and voltage regulation and imposing automatic voltage control obligations.

Distributed Energy Resources

A developing area that MISO is addressing is Distributed Energy Resources (DERs). MISO has begun discussing the challenges that are anticipated to arise from these resources, especially with visibility and uncertainty around operation of these resources. They are generally going to be located and operated on the distribution system, yet FERC has ordered that DERs be able to participate in all aspects of the RTO markets, which creates RTO challenges.[12]

According to the 2024 OMS DER Survey, 13.6 GW of DERs currently exist in MISO. Of this, 42 percent is solar PV, 43 percent is demand response, and the rest are other DER types that include battery storage and small-scale generation. Although we do not anticipate rapid entry of DER resources, MISO should be prepared because technologies and business models can change rapidly. DERs will present the following unique challenges for MISO's markets and operations:

- *Operational Visibility*: The output level and location of DERs may be uncertain in the real-time market, leading to challenges managing network congestion and balancing load.
- *Operational Control*: Unlike conventional generation, most DERs will not be controllable on a five-minute basis. This has important implications for how DERs are integrated operationally through the MISO markets.
- *Economic Incentives*: To the extent that DERs participate in or are affected by retail rates, they may face inefficient incentives to develop and operate the DERs.

12 Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 172 FERC ¶ 61,247 (2020).

MISO is engaging stakeholders to identify technical, market, and reliability issues associated with alternative DERs. As MISO develops new market rules and processes, it should seek to ensure that DERs will support reliability and provide efficient incentives for DERs and non-DERs. To achieve these two goals, we recommend that MISO employ the following objectives:

- *Comparable and Verifiable Performance*. DERs participating in energy markets should have comparable performance and verification requirements to other types of units.
- *Distinguish Between Controllable and Uncontrollable*. DERs that are not controllable (e.g., rooftop solar, energy efficiency) present additional forecasting challenges and do not support reliability in the same manner as controllable DERs.
- *Operate and settle locationally*. The locational effects of DERs must be reflected in MISO's operations and settlements in order to provide efficient investment incentives and to utilize them effectively. Hence, accurate locational metering will be essential.
- *Avoid Duplicative Payments*. In many cases DERs will already be participating in non-wholesale markets or distribution programs. Duplicative payments will provide inefficient investment and operating incentives and should be avoided if possible.
- *Develop accurate accreditation methods for DERs*. Most DERs will be less accessible and controllable than conventional resources. Accurate accreditation is essential to providing efficient incentives to invest in DERs and other resources needed for reliability.

Energy Storage Resources

Order No. 841 required MISO to enable Energy Storage Resources (ESRs) to participate in the market, recognizing the operational characteristics of ESRs. By the end of 2024, eight ESRs were participating in MISO with a total of 290 MW. Figure 12 above shows that MISO forecasts only moderate growth in ESRs over the next decade.

Based on the trends in other markets and resources in MISO's interconnection queue, we believe this forecast is likely conservative. Installation costs of ESRs should fall as they proliferate, and their economic value will grow as the penetration of intermittent resources grows. This is particularly true if MISO improves its shortage pricing as described below, which would efficiently compensate ESRs for the value they provide in mitigating or eliminating transitory shortages.

ESRs can provide tremendous value in reliably managing the fluctuations in intermittent output. However, ESRs are not fully substitutable for conventional generation, especially as the quantities of ESRs rise, which causes their marginal value to fall. Therefore, it will be critical to adopt an accurate accreditation methodology for ESRs as we discuss in the following subsection.

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

MISO has managed the growth in intermittent resources reliably. Some have suggested that fundamental changes in MISO's markets are needed in response to the dramatic generation portfolio changes – but this is *not* true. MISO's markets are robust and well-suited to facilitate this transition, although improvements will be needed. MISO has already begun the process of making necessary changes to accommodate higher levels of intermittent resources, including:

- Introducing a ramp product to increase the dispatch flexibility of the system;
- Developing the DIR capability to improve its ability to control its wind resources;
- Implementing the Short-Term Reserve Product and dynamically adjusting the requirements to manage uncertainty;
- Reforming shortage pricing to compensate resources that are available and flexible and that allow MISO to maintain reliability when shortages arise;
- Reforming capacity accreditation so that resource capacity credits under Module E accurately reflect reliability values; and
- Introducing a seasonal capacity market with reliability-based demand curves that will align with the marginal reliability value that capacity provides.

These reforms are essential because they improve the operation of the system and more efficiently compensate the dispatchable resources needed to balance the uncertain and often volatile output of the rapidly growing fleet of intermittent resources. As the resource fleet transitions, however, additional operational issues will arise. The vast majority of these issues can be addressed with the following improvements to the MISO markets in two key areas:

1. Improvements in the Energy and Ancillary Services Markets
   - Introducing an uncertainty product to reflect MISO's need to commit resources to have sufficient supply available in real time to manage uncertainty; and
   - Implementing a look-ahead dispatch and commitment model in the real-time market.
2. Improvements in the Operation and Planning of the Transmission System
   - Introduction of new processes to optimize the operation of the transmission system and improve its utilization; and
   - Improvements to the transmission planning processes and benefit-cost analyses.

These improvements are discussed in the following subsection.

1. Improvements in the Energy and Ancillary Services Markets

Energy and ancillary services markets will be key in the transition to a cleaner generation portfolio because they will ensure that MISO fully utilizes its supply and demand resources to efficiently maintain reliability, while also providing critical incentives that govern the development and operation of its resources. The following are key improvements in this area.

Uncertainty Product

As MISO transitions to a fleet that is far more dependent on intermittent resources, supply uncertainty will increase markedly, affecting MISO's planning and operations. MISO has correctly concluded that the availability and flexibility of its non-intermittent resources will be paramount to ensuring it can maintain reliability. Figure 15 shows the "net uncertainty" that MISO currently faces in the operating horizon. This is based on historical data on the combined impact of generation forced outages and forecast errors from load and renewables. We calculate the typical uncertainty (the 50th percentile) and in the hours when uncertainty is higher (higher percentiles). The figure shows the uncertainty one hour ahead and four hours ahead (blue bars). The red, green, and purple lines indicate the underlying contributing factors of load forecast error, renewable forecast error, and generating resource trips and derates in 2024.

Figure 15: Uncertainty and MISO's Operating Requirements
January 2023 to December 2024

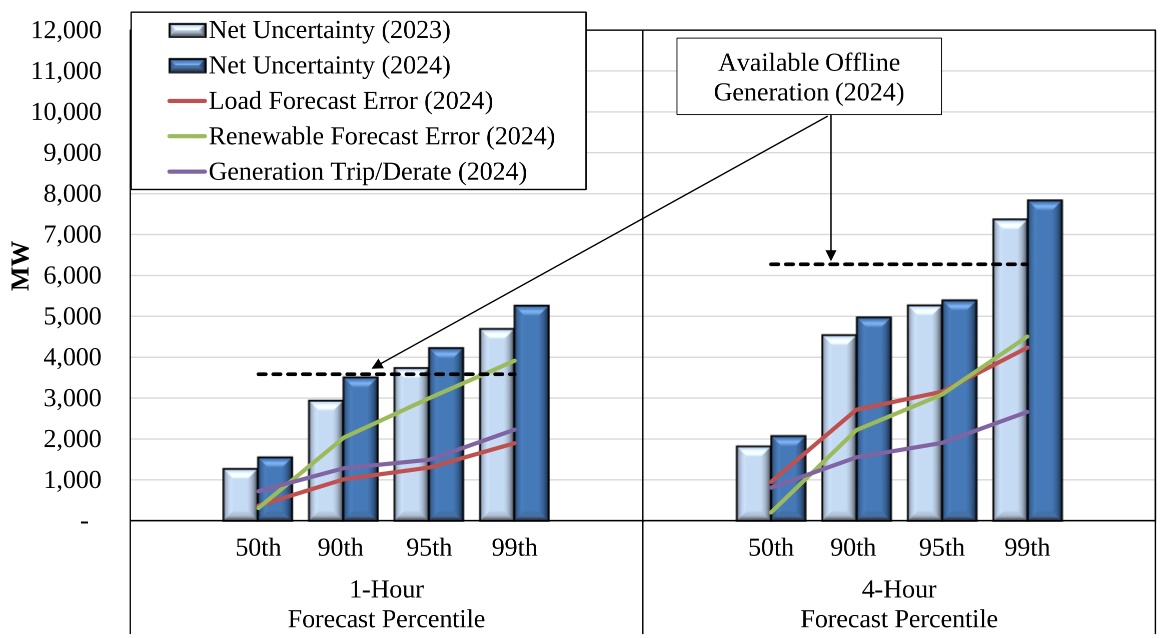


Figure 15 shows that net uncertainty increased in 2024 from 2023, driven by increased renewable forecast errors. MISO often commits resources outside of the market to ensure it will have sufficient generation available to respond to uncertainty, which results in RSG costs. Reflecting these needs in a market product would allow prices to efficiently reflect them, result in fewer out-of-market actions by MISO, and eliminate the associated RSG costs.

As intermittent generation increases, these operational needs and out-of-market costs are likely to rise substantially. Hence, we recommend that MISO develop an uncertainty product for the day-ahead and real-time markets to account for increasing uncertainty associated with load, intermittent generation, NSI, and other factors. In 2024, MISO began to address uncertainty by dynamically raising its short-term reserve requirements, which is a 30-minute product. This is a positive change, but resources need not be able to start in 30 minutes to address uncertainty. Hence, the uncertainty product could allow resources with longer lead times to sell the product, e.g., two to four hours. It would also allow MISO's prices to reflect the need for this capacity to address uncertainty, reduce RSG, and reward the flexible resources that can meet this need.

Look-Ahead Dispatch and Commitment

In the longer term, we also recommend MISO implement a look-ahead dispatch and commitment model that would optimize the dispatch of resources over multiple future dispatch intervals spanning an hour or more. Managing the sharp increases and decreases in net load (load minus intermittent output) will create extreme ramp needs for the remaining dispatchable resources, which could be as high as almost 40 GW in three hours given the amount of solar resources coming online. Although these ramp demands can be managed in a variety of ways, most would require costly out of market intervention by the operators. Therefore, we believe it will be essential for MISO to implement a look-ahead dispatch and commitment model to optimize:

- The dispatch of slower-ramping resources that may need to begin ramping 15 to 30 minutes in advance of a sharp increase in net load or at times of increased uncertainty;
- The intra-day commitment of resources that can start in ten minutes to two hours; and
- The utilization of storage resources, DERs, and resources with energy limitations.

Optimizing the commitment and dispatch of resources will reduce the costs of managing net load fluctuations and reduce the uplift costs that would otherwise likely be considerable. As the penetration of intermittent and storage resources increases, these benefits will grow, and the look-ahead dispatch will be increasingly critical for meeting the reliability needs of the system.

2. Improvements in the Operation and Planning of the Transmission System

As intermittent output grows and the variability of the flows over the transmission network increases, critical bottlenecks are likely to emerge that will continue to increase congestion and lead to growing levels of output curtailments. Therefore, maximizing the utilization of the transmission network and facilitating efficient transmission upgrades will be key. MISO's work with transmission owners to submit ambient-adjusted and emergency ratings is the first essential step toward greater utilization of the network and other key improvements are discussed below.

Transmission Optimization

One of MISO's core functions is ensuring the transmission system can reliably support the MISO markets. New challenges will emerge with the accelerating growth of renewables, partly because large fluctuations in intermittent output can cause substantial changes in transmission flows. This can cause erratic congestion patterns that are more difficult to forecast. Options for addressing these challenges may include technologies and processes that allow MISO to optimize the operation of the network by redirecting flows to minimize congestion, or by using dynamic line ratings for transmission facilities to recognize factors other than temperatures.

These technologies may enable large cost savings with little or no impact on reliability. These technologies have been referred to as "grid-enhancing technologies" (GETs) and the processes are referred to as "grid optimization". In addition to reducing congestion, these processes and technologies may improve MISO's ability to plan for and manage transmission and generation outages, as well as fluctuations in flows caused by loads and intermittent generation. Realizing the benefits of such technologies and process improvements will require that MISO devote resources in the coming years to integrating such technologies into its operations and systems.

Long-Range Transmission Planning

As MISO's generation portfolio is transformed, its transmission network will need to evolve to facilitate the delivery of the clean resource output to MISO loads. This evolution is guided by MISO's planning studies to identify the constraints that will limit this delivery and transmission investments that would mitigate these constraints. Many of these investments are identified in the Long-Range Transmission Planning (LRTP) process, which will ultimately include 4 tranches.

Tranche 1, approved in 2022, allocates $10.3 billion in investments to address constraints in the Midwest region. Tranche 2.1 was approved in December 2024, allocating more than $20 billion to 24 projects that will span over 3,600 miles of transmission in the Midwest. Tranches 3 (South) and 4 (interregional transfers) will address needed transmission upgrades, assuming higher future loads resulting in greater intermittent penetration. It will be increasingly important that these investments are economically efficient because: a) large-scale investment is very costly; and b) inefficient upgrades can undermine suppliers' incentives to make resource investment and retirement decisions that would mitigate congestion at lower costs.

To ensure future transmission investments are economically efficient and will benefit MISO customers, MISO must:

- Establish realistic future scenarios to be used to identify future transmission needs and the investments to address them; and
- Conduct benefit assessments that accurately quantify the benefits of the proposed investments.

We had concerns in both regards, which we summarize in this subsection.

Future 2A is not realistic. This is largely because the capacity expansion model (I) predicts an excessive amount of intermittent renewable resources will be built and (ii) understates investment in dispatchable and storage resources. This is concerning because both problems tend to increase the expected need for new transmission. In November 2024, MISO announced it will update its futures scenarios to include expected increases in load that were not fully incorporated in the existing future scenarios.

Many categories of benefits are likely to be overstated. MISO estimated nine classes of savings, and all of these savings were dependent on where resources are located on the ISO system. The most pervasive concern is that MISO's methodologies did not account for market incentives that affect long-term resource citing decisions. In other words, it assumed resources would site in the same locations with or without transmission, which is unreasonable to assume and affects all of its benefit estimates.

Our most significant concerns with specific classes of benefits pertained to the avoided capacity costs and the mitigation of reliability issues. The avoided capacity costs would likely be very low if MISO recognized that resources will site in different locations if Tranche 2 is not built. The mitigation of reliability issues is quantified assuming MISO will frequently *shed load* to address voltage or other local issues without Tranche 2. This is not realistic because MISO addresses these issues by reconfigurations, activating thermal proxies, or by investments in other equipment – each of which is much less expensive than load shedding and are the appropriate basis for quantifying this benefit. Unfortunately, these two classes constitute roughly two-thirds of the estimated benefits and, if properly calculated, the benefit-cost ratio of Tranche 2 would likely be far below 1.0.

The concerns described above introduced a significant bias in favor of large-scale transmission facilities, many of which may not ultimately be economic. Hence, we recommend that MISO reform its planning process to address these concerns in future Tranches.

3. Improvements in the Capacity Market

In addition to the opportunities for improvements described above, MISO has implemented a number of key changes to the capacity market that will be essential. As in other RTO markets, the capacity market plays a key role in facilitating efficient investment and retirement decisions. Although most of the participants in the MISO markets are vertically-integrated regulated utilities, efficient capacity market outcomes will nonetheless provide key incentives that influence these long-term decisions and resource planning processes. Additionally, MISO has a number of merchant generators and other unregulated participants. Hence, ensuring that the capacity markets provide efficient economic signals is essential.

MISO took key steps to do this by: a) implementing a seasonal market, b) implementing reliability-based demand curves at FERC in the 2025–2026 Planning Year, and c) filing important changes to its capacity accreditation to be implemented in the 2028–2029 Planning Year to reflect resources' true *marginal* reliability value based on their expected availability to provide energy or reserves when the system is at risk of load shedding.[13] This last change is essential for the transition of the generating fleet because it will send efficient incentives to developers and inform utilities' integrated resource planning processes to ensure that future investment will satisfy the reliability needs of the MISO region.

4. Conclusions

As substantial changes continue on the MISO system, it is critical that the markets support and facilitate these changes. MISO has proposed or implemented key improvements over the past two years to its capacity and energy markets. We recommend the remaining changes that will be needed to successfully navigate this clean energy transition, the most important of which is: a) implementing a real-time look-ahead dispatch and commitment model, b) introducing an uncertainty product, and c) improving the transmission planning process.

13 See MISO's filing in Docket No. ER24-1638-000 and the accompanying affidavit of Dr. David Patton, which proposes a Direct Loss-of-Load (DLOL) marginal accreditation approach for all resources in the footprint.

IV. Energy Market Performance and Operations

MISO's electricity markets operate together 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.[14] The real-time market clears based on actual physical supply and demand, settling any deviations from day-ahead contracts at real-time prices.[15] The performance of both markets is essential, the day-ahead market because:

- Most resources in MISO are committed through the day-ahead market, so good market performance is essential to ensure efficient commitment of MISO's resources;[16]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market – 100.3 percent in 2024 (net of virtual transactions); and
- The value of entitlements for firm transmission rights is determined by day-ahead market outcomes (i.e., payments to FTR holders are based on day-ahead congestion).

Real-time market performance is also crucial because it governs the optimal physical dispatch of MISO's resources, while also establishing prices that indicate the real-time value of energy and ancillary services. These prices send economic signals that facilitate scheduling in the day-ahead market and longer-term investment and retirement decisions. This section evaluates the performance and operations of the day-ahead and real-time markets in key areas.

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

The day-ahead energy prices tracked the real-time price trends described in Section II, falling in 2024 as natural gas prices continued to decrease. Average day-ahead energy prices decreased four and a half percent from 2023 to $30 per MWh. Congestion caused day-ahead prices at MISO's hubs to range on average from $24 per MWh at the Arkansas Hub to roughly $31 per MWh at the Indiana Hub.

An important difference between the day-ahead and real-time markets is that the day-ahead market clears hourly schedules while the real-time market clears on a five-minute basis. This creates some issues in managing MISO ramp demands – i.e., the need to schedule generation to rise or fall gradually as load and other conditions change over the day. Because large changes in supply tend to occur at the top of the hour when day-ahead schedules change, prices tend to spike at these times. In 2024, MISO experienced 7 intervals of $3500 per MWh pricing that were

14 In addition to day-ahead market commitments, MISO utilizes the Multi-Day Forward Reliability Assessment Commitment process to commit long-start-time resources to satisfy reliability needs in certain load pockets.

15 In addition, deviations that are due to deratings or outages are subject to allocation of uplift payments. Virtual and physical transactions scheduled in the day-ahead market are also subject to these charges.

16 After the day-ahead market, MISO runs its Forward Reliability Assessment Commitment (FRAC) and Look-Ahead Commitment (LAC) process that may cause MISO to make additional commitments.

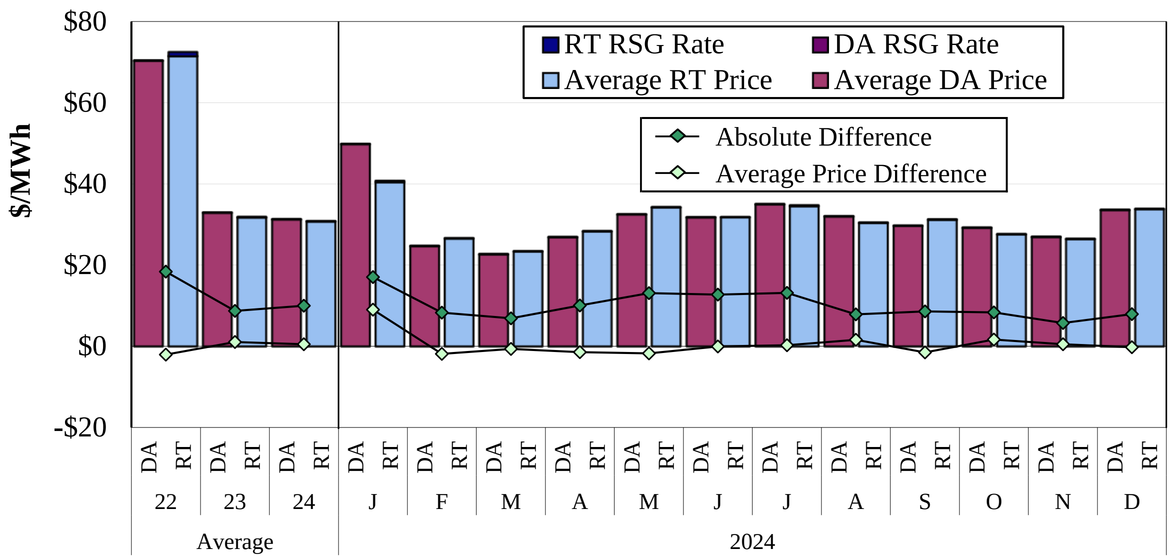
caused by this issue. In December, MISO implemented a ramp requirement floor to procure sufficient ramp capability to mitigate these issues until a longer-term solution is implemented. We had previously recommended MISO evaluate the feasibility of transitioning to a 15-minute day-ahead market, which MISO has determined is not currently feasible.

The primary measure of performance of the day-ahead market is how well its prices converge to the real-time market prices. The real-time market clears actual physical supply and demand, and participants' day-ahead market bids and offers should reflect their expectations of market conditions for the following day. However, several factors can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead market, such as wind or load forecast error, real-time output volatility, and forced generation or transmission outages. While these factors may limit convergence in a well-performing market on an hourly basis, prices should converge over longer timeframes (monthly or annually).

Figure 16 shows monthly and annual price convergence statistics. The upper panel shows the monthly average prices plus the allocated RSG costs for the Indiana Hub. The real-time RSG charges (allocated partly to real-time deviations from day-ahead schedules) tend to be much larger than day-ahead RSG charges (allocated to day-ahead energy purchases). The lines show two measures of the difference between day-ahead and real-time prices. The bottom table shows the average difference (as a percentage) between day-ahead and real-time prices for six hub locations in MISO, accounting for the allocated RSG costs.

Figure 16: Day-Ahead and Real-Time Prices at Indiana Hub

2022–2024



Average DA-RT Price Difference Including RSG (% of Real-Time Price)

Indiana Hub	-3	3	2	22	-7	-3	-5	-5	0	1	5	-5	6	2	-1
Michigan Hub	-1	3	0	21	-5	-1	-4	-21	1	1	5	-5	4	2	-1
Minnesota Hub	0	-1	-1	5	-3	-5	-7	1	4	-9	4	-7	7	8	-5
Arkansas Hub	-2	2	1	14	-4	-3	-4	-4	-2	-4	6	-4	3	13	0
Louisiana Hub	-1	4	1	13	-3	-3	-3	1	-2	-7	10	-6	1	8	-2
Texas Hub	-1	4	1	6	-2	-3	-1	-5	-1	-5	14	-2	2	9	-1

These results indicate that price convergence was good overall. Day-ahead prices were about two percent higher than real-time prices after adjusting for the real-time RSG costs, which averaged $0.11 per MWh.

B. Virtual Transactions in the Day-Ahead Market

A large share of the liquidity that facilitates good day-ahead market performance is provided by virtual transactions. Virtual transactions are financial purchases or sales of energy in the day-ahead market that do not correspond to physical load or resources. Virtual buyers (or sellers) enter the real-time long (or short). Because they do not produce or consume physical energy, virtual transactions' positions settle against real-time prices. Virtual transactions are essential facilitators of price convergence because they are used to arbitrage price differences between the day-ahead and real-time markets. Figure 17 shows the average offered and cleared virtual supply and demand. The figure separately shows financial-only participants and physical participants.

Figure 17: Virtual Demand and Supply in the Day-Ahead Market
2024

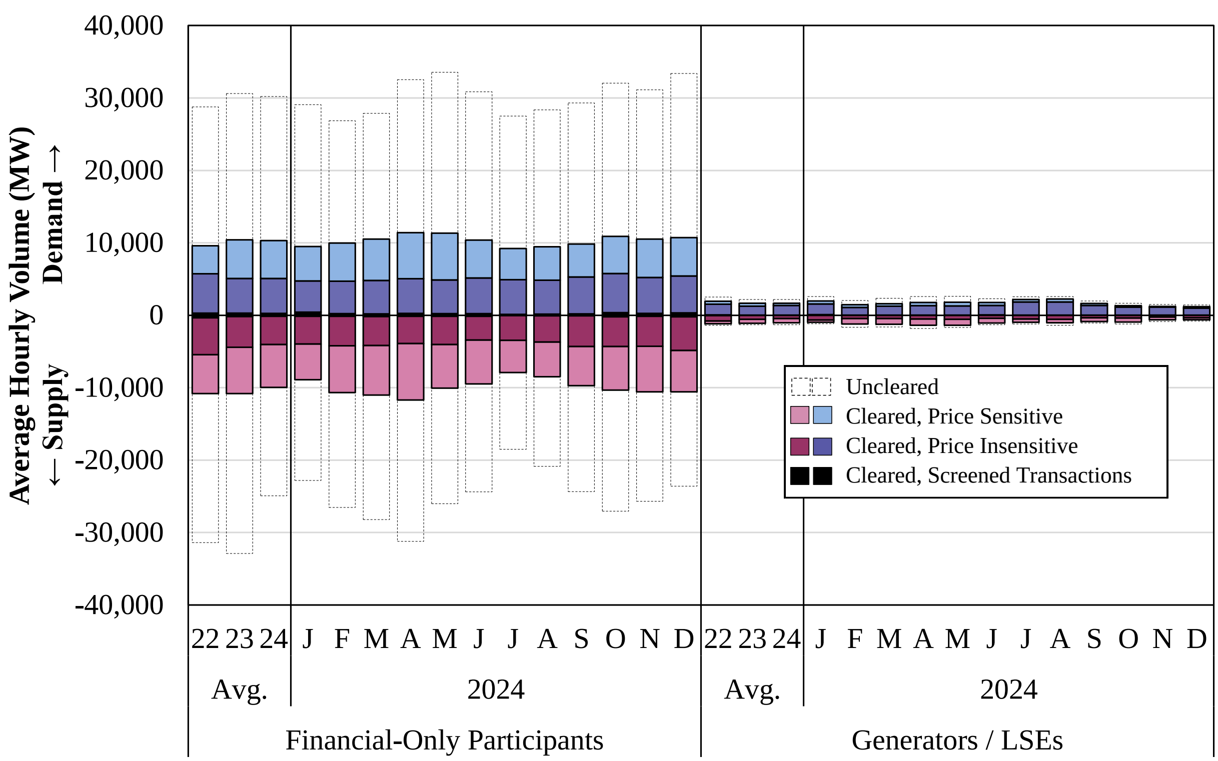


Figure 17 shows that financial participants continue to account for the vast majority of virtual transactions, and the limited quantities scheduled by physical participants fell roughly three percent from 2023. This figure shows the following key findings and trends:

- In total, cleared transactions decreased by four percent, driven by decreases in cleared virtual activity of six percent in the Midwest and of four percent in the South.

- Financial participants offer more price-sensitively, providing day-ahead market liquidity.
- Several participants submit “backstop” bids and offers that are priced well below (for demand) or above (for supply) the expected price range. Backstop bids and offers clear less than one percent of the time, but they are substantially profitable when they do clear. They are beneficial because they mitigate particularly large day-ahead price deviations.
- Bids and offers that are price-insensitive (i.e., offered at prices making them very likely to clear) constitute a significant share of all virtual transactions. They provide less liquidity to the market and can raise manipulation concerns.
- Most price insensitive transactions are used to arbitrage congestion-related price differences by allowing participants to establish an energy-neutral position between two locations (offsetting virtual supply and demand positions at two locations). We refer to these transactions as “matched” transactions.
- Matched transactions avoid RSG deviation charges and carry no energy price risk. Their average hourly volume decreased by six percent from 2023 to 1,500 MW.
- We continue to recommend MISO implement a “virtual spread product” that would allow participants to engage in such transactions price-sensitively. Comparable products exist in both PJM and ERCOT.
- Price-insensitive transactions that cause congestion *divergence* between the day-ahead and real-time markets (labeled “Screened Transactions”) raise potential manipulation concerns. They were only 1.9 percent of all transactions and raised no concerns in 2024.

Virtual Activity and Profitability

Gross virtual profitability fell 37 percent in 2024 to average $0.44 per MWh, down from $0.70 per MWh in 2023. In 2024, demand profitability increased by 44 percent to $0.39 per MWh, and supply profitability decreased by 55 percent to $0.51 per MWh. The increase in shortage pricing from 2023 increased virtual demand profitability and reduced virtual supply profitability. In general, gross profits are higher for virtual supply because more than 20 percent of these profits are offset by real-time RSG costs allocated to participants with net virtual supply positions. This allocation eliminates the incentive for virtual suppliers to pursue low-margin arbitrage opportunities. Virtual demand does not bear capacity-related RSG costs because they reduce the need for real-time capacity commitments. Virtual transactions by financial participants remained generally more profitable than transactions submitted by physical participants, averaging $0.47 per MWh compared to $0.23 per MWh.

To provide perspective on the virtual trading in MISO, Table 2 compares virtual trading in MISO to trading in NYISO, ISO New England, SPP, and PJM. This table shows that virtual trading is generally more active in MISO than in other RTOs, even after adjusting for the much larger size of MISO. This is partly due to MISO’s more efficient allocation of RSG costs. The table also shows that liquidity provided by virtual trading in MISO translates to relatively low virtual profits. Gross virtual supply profits are higher than virtual load because of the RSG cost allocation discussed above.

Table 2: Comparison of Virtual Trading Volumes and Profitability
2024

Market	Virtual Load		Virtual Supply	
	MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit
MISO	15.8%	$0.39	14.5%	$0.51
NYISO	6.3%	-$0.64	7.4%	$0.82
ISO-NE	3.1%	-$2.64	6.6%	$2.21
SPP	10.1%	$0.64	15.9%	$3.83
PJM	5.9%	$0.05	5.6%	$1.20

Low virtual profitability is consistent with an efficient day-ahead market, which is important because the day-ahead market coordinates the daily commitment of MISO's resources. Although overall profitability is a positive indicator, the next subsection contains a more detailed analysis of virtual transactions to determine the share that improves day-ahead market outcomes.

Benefits of Virtual Trading

We studied the contribution of virtual trading to market efficiency in 2024. We determined that 56 percent of all cleared virtual transactions in MISO were efficiency-enhancing and led to convergence between the day-ahead and real-time markets. The majority of efficiency-enhancing virtual transactions were profitable based on congestion modeled in the day-ahead and real-time markets and the marginal energy component (system-wide energy price).

A small share of the efficiency-enhancing virtual transactions was unprofitable, which occurs when virtual transactions over-converge the congestion trend to which they are responding. We did not include profits from un-modeled constraints or from loss factors in our efficiency-enhancing category because these profits do not increase day-ahead efficiency. A detailed description of our methodology can be found in the Analytic Appendix in Section IV.G.

Virtual transactions that were not efficient led to divergence and were generally unprofitable based on the energy and congestion on modeled constraints. However, they can be profitable when they profit from un-modeled constraints or loss factor differences. Table 3 shows the total amount of efficient and inefficient virtual transactions by market participant type.

The table shows that 56 percent of all virtual transactions were efficiency-enhancing. Convergent profits were positive on net for all virtual transactions by $25 million. However, this value significantly understates the net benefits of the virtual transactions because it measures the profits at the margin.

In other words, the total benefit is much greater than the marginal benefit, because:

- The profits of efficient virtual transactions become smaller as prices converge; and
- The losses of inefficient virtual transactions get larger as prices diverge.

Table 3: Efficient and Inefficient Virtual Transactions by Type of Participant in 2024

Transaction Category	Financial Participants			Physical Participants		
	MWh	Convergent Profits	Rent-Seeking	MWh	Convergent Profits	Rent-Seeking
Efficiency Enhancing (Profitable)	86,466,568	$1,126.6M	-$14.7M	10,516,109	$119.8M	$.3M
Efficiency Enhancing (Unprofitable)	13,720,911	-$89.7M	$14.5M	1,968,372	-$10.3M	$1.7M
Not Efficiency Enhancing (Profitable)	5,142,360	-$21.9M	$48.2M	849,085	-$2.4M	$4.9M
Not Efficiency Enhancing (Unprofitable)	72,557,425	-$986.6M	$8.1M	10,485,792	-$110.4M	$2.0M
Total	**177,887,264**	**$28.4M**	**$56.1M**	**23,819,358**	**-$3.4M**	**$8.8M**

Although we are not able to rerun the day-ahead and real-time market cases for the entire year, this analysis provides a high degree of confidence that virtual trading was beneficial in 2024.

C. Real-Time Market Pricing

Efficient real-time market outcomes are essential because they provide incentives for suppliers to be available and to respond to dispatch instructions. They also inform forward price signals for day-ahead scheduling and long-term investment and maintenance. In this subsection, we evaluate whether real-time prices efficiently reflect prevailing conditions. However, we do not discuss pricing during energy or reserve shortages in this subsection because it is addressed in Section III discussing the future needs of the MISO markets. Efficient shortage pricing is essential for the market to perform well, especially as the reliance on intermittent resources rises.

Fast-Start and Emergency Pricing by the ELMP Model

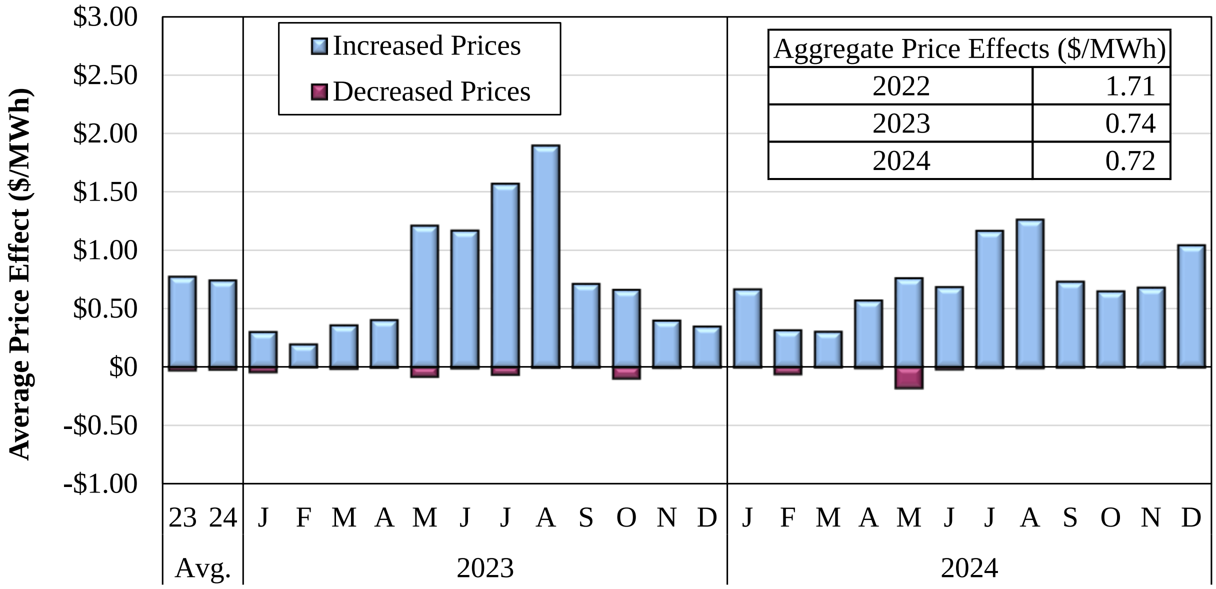
Beyond shortage pricing, a key element of MISO's real-time pricing is its Extended Locational Marginal Pricing (ELMP) algorithm that was implemented in March 2015. While MISO's dispatch model calculates "ex ante" real-time prices every five minutes, these prices are re-calculated by the ELMP model and used for real-time settlements. ELMP is intended to improve price formation by establishing prices that better reflect the true marginal costs of supplying energy and ancillary services at each location. ELMP allows Fast-Start Resources (FSRs) and emergency resources to set prices when needed and economic to satisfy the system's needs.[17]

When FSRs or emergency resources are not reflected efficiently in prices, the resulting understatement of prices leads to higher RSG costs and poor pricing incentives for scheduling generation and interchange. Although FSRs may not appear to be marginal in the five-minute

17 Emergency supply is priced by applying a $500/MWh offer price floor (Tier 1) to this supply in ELMP when MISO declares a Max Gen Warning and a $1000/MWh floor (Tier 2) in a Max Gen Event Step 2.

dispatch, the ELMP model recognizes that peaking resources are marginal and should set prices to the extent they are needed to satisfy the system's needs. The following figure summarizes the effects of the ELMP pricing model in 2024.

Figure 18: The Effects of Fast Start Pricing in ELMP
2023–2024



% of Intervals Affected by > +/- $0.10

SMP Increase	53	52	42	37	59	46	58	60	60	61	52	60	55	46	56	45	43	58	50	42	64	51	49	51	51	57
SMP Decrease	1	1	0	0	3	1	1	1	1	0	0	2	1	1	1	0	0	1	1	1	0	0	0	0	0	1

Figure 18 shows that the effects of ELMP on real-time energy prices fell three percent in 2024. This decrease was due to lower gas prices in 2024. The performance of ELMP has been good partly because of the improvements MISO made over time. ELMP had almost no effect in the day-ahead market because the supply is far more flexible and includes virtual transactions.

Modifying the Market Pricing during LMR Deployments

While EEA2 events that prompt MISO to deploy LMRs have been rare, pricing during these events has not been efficient in many cases. The ELMP model that produces prices during emergency conditions determines whether emergency resources should set prices by attempting to dispatch them down and allow other resources to replace them. The theory is that if the ELMP model cannot ramp the resources to zero, then they are needed and should set real-time prices. While this is reasonable in most cases, it is not always reasonable for LMRs because they are usually deployed in large quantities (3 to 6 GWs). The ELMP model generally lacks the ramp capability on conventional resources to replace the LMRs in a single dispatch interval. Therefore, they often set prices long after they are no longer needed. This has resulted in:

- Elevated prices and excessive non-firm imports as participants respond to these prices;

- High prices extending beyond the emergency area to all of MISO once supply is adequate and the constraint into the area unbinds; and
- Large uplift payments in the form of price-volatility make-whole payments that must be made to resources that are held down to make room for the LMRs and non-firm imports.

We recommend MISO consider revising its emergency pricing model to reintroduce LMR curtailments as Short-Term Reserves, instead of energy demand, to produce more efficient emergency pricing and better align ex-ante and ex-post results. The STR requirements would expand to include the amount of LMRs scheduled, and the associated demand curve would adjust to reflect the prevailing emergency offer floor price. We previously validated the value of this approach by simulating the emergency that occurred on June 10, 2021, which is described in the *2021 State of the Market Report*.

D. Uplift Costs in the Day-Ahead and Real-Time Markets

Evaluating uplift costs is important because these costs are difficult for customers to forecast and hedge, and they generally reveal areas where the market prices do not fully capture the cost of system requirements. Most uplift costs are the result of guarantee payments made to participants. MISO employs two primary forms of guarantee payments to ensure resources cover their as-offered costs and provide incentives to be available and flexible:

- Revenue Sufficiency Guarantee (RSG) payments ensure the total market revenue for a unit committed economically or for reliability is at least equal to its as-offered costs over its commitment period; and
- Price Volatility Make-Whole Payments (PVMWP) ensure suppliers will not be financially harmed by following the five-minute dispatch signals.

Resources committed before or in the day-ahead market may receive a day-ahead RSG payment as needed to recover their as-offered costs. Resources committed by MISO after the day-ahead market receive a real-time RSG payment as needed to recover their as-offered costs. The day-ahead RSG costs for economic commitments are recovered on a pro-rata basis from all scheduled load. The real-time RSG costs are recovered via charges to participants that cause the costs, and the residual is charged to load. This allocation generates efficient incentives for participants.

Day-Ahead and Real-Time RSG Costs

Figure 19 shows monthly day-ahead RSG costs categorized by the underlying cause. Most RSG payments for Voltage and Local Reliability (VLR) are made in the day-ahead market because most VLR commitments are made before or during the day-ahead market process. Because fuel prices have considerable influence over suppliers' production costs, the figure shows RSG payments in both nominal and fuel-adjusted terms.[18] The maroon bars show all the RSG paid to

18 Fuel-adjusted RSG payments are indexed to the average three-year fuel price of each unit.

units started for VLR before the day-ahead market cleared, except that the VLR costs incurred for the Southeast Texas (SETEX) Op Guide is shown in the maroon striped bars. The blue part of the bars shows RSG incurred for commitments made to maintain system-wide capacity.

Nominal day-ahead RSG payments fell eight percent in 2024 to total $30 million, which is in line with falling gas prices year over year. Around 36 percent all day-ahead VLR costs accrued to units in two load pockets in MISO South, while an additional 6 percent accrued to units committed for transmission work in Michigan. Most of the day-ahead RSG categorized for capacity was paid to cover the resources' startup costs.

Figure 19: Day-Ahead RSG Payments
2023–2024

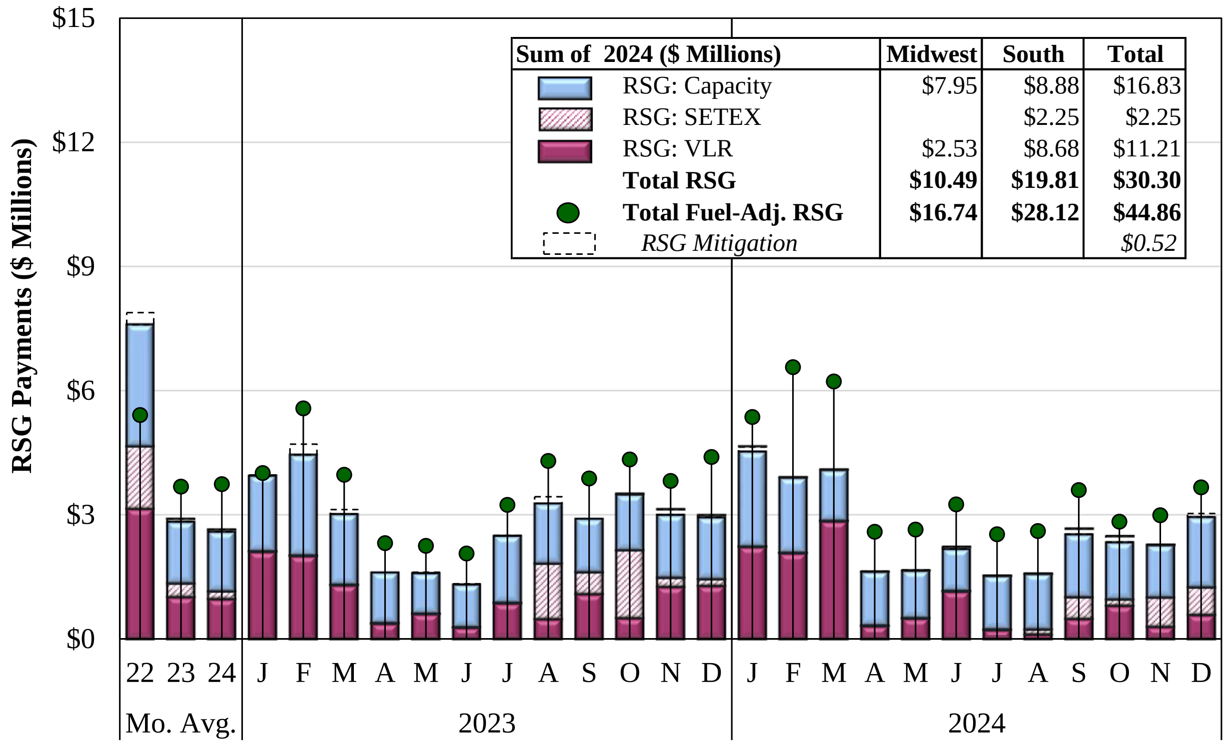
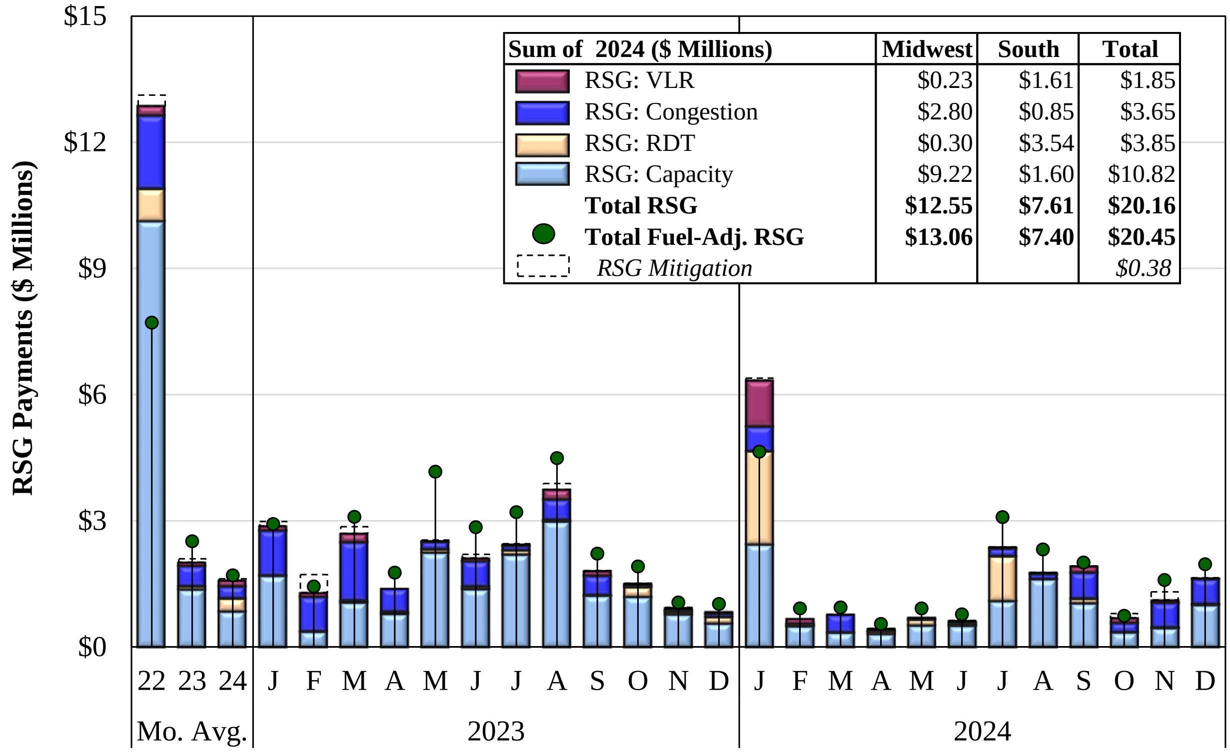


Figure 20 shows categories of RSG payments for the real-time market, which includes RSG costs for units committed to: (a) manage congestion, (b) manage RDT flows, or (c) create regional reserves. The elevated levels of RSG in January were related to Winter Storm Heather. MISO's preparation for the Storm resulted in lower RSG than experienced in previous years with storms of comparable magnitude. We describe the events that occurred in Winter Storm Heather in Section II.E.

Figure 20 also shows the sharp decrease in real-time RSG costs from 2022 to 2024. Some of this decrease was due to falling natural gas prices, but most of it was due to significant improvements in MISO's commitment processes. In our prior reports, we raised concerns that a large share of the out-of-market commitments that produce real-time RSG costs were not necessary to meet MISO's real-time reliability needs. This was a key concern because excess supply in real time tends to lower (and distort) real-time prices, raise RSG, and weaken the incentive to fully schedule resources in the day-ahead market.

Figure 20: Real-Time RSG Payments
2023–2024



Sum of 2024 ($ Millions)	Midwest	South	Total
RSG: VLR	$0.23	$1.61	$1.85
RSG: Congestion	$2.80	$0.85	$3.65
RSG: RDT	$0.30	$3.54	$3.85
RSG: Capacity	$9.22	$1.60	$10.82
Total RSG	**$12.55**	**$7.61**	**$20.16**
Total Fuel-Adj. RSG	**$13.06**	**$7.40**	**$20.45**
RSG Mitigation			*$0.38*

We have recommended a number of improvements and MISO has worked closely with us to implement many of them, including (i) increasing STR requirements to address uncertainty rather than committing resources, (ii) eliminating the headroom requirement in LAC, (iii) lowering the operating reserve demand curves in LAC to be better aligned with those used in the markets, and (iv) deferring commitments that do not need to be made immediately given resources' start-up times. These changes have substantially improved MISO's commitment processes and mitigated the adverse effects of out-of-market commitments on real-time prices and costs.

Price Volatility Make-Whole Payments

PVMWPs address concerns that resources can be harmed by responding to volatile five-minute price signals. Hence, these payments provide suppliers the incentive to offer flexible physical parameters. They come in two forms: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Offer Revenue Sufficiency Guarantee Payments (RTORSGP). DAMAP payments are made when resources produce output at a level less than both the day-ahead schedule and the economic output level given its offer price. RTORSGP payments are made when a unit is operated higher than its economic output level. Table 4 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). We separately indicate the amount of PVMWP MISO incurred excluding Winter Storm Elliott in December 2022, given the magnitude of the payments during that storm.

Table 4: Price Volatility Make-Whole Payments ($ Millions)
2022–2024

	DAMAP		RTORSGP		Total	Market-Wide Volatility	Locational Volatility
	Midwest	South	Midwest	South			
2024	$44.4	$8.1	$3.3	$0.6	$56.4	21.0%	26.8%
2023	$35.8	$3.3	$3.8	$0.8	$43.7	15.5%	21.0%
2022*	$69.9	$11.1	$5.2	$1.5	$87.7	15.2%	21.0%
WS Elliott	$23.0	$0.7	$0.0	$0.1	$23.8		

*** Excludes winter storm events (Elliott in 2022)**

PVMWPs increased 29 percent from 2023. Ancillary services shortages caused more frequent price spikes in 2024, and DAMAP paid to generators during ancillary services shortages increased by 67 percent from 2023. Additionally, the RDT bound more frequently during 2024, which caused prices in the Midwest to rise by up to $500 per MWh and contributed to large, slower-moving resources receiving DAMAP. DAMAP from RDT-related price spikes increased by 50 percent in 2024.

E. Regional Directional Transfer Flows and Regional Reliability

The scheduled transfers between the South and Midwest are constrained by contractual limits. MISO has taken two actions to prevent exceeding these limits: (a) implementing a post-contingent constraint to hold headroom on the RDT, called the Reserve Procurement Enhancement (RPE), and (b) actively managing the RDT limit to avoid unmodeled exceedances. The latter involved MISO binding the RDT in real time at an average of 390 MW below its contractual limit in 2024. Importantly, limiting interregional transfers that do not contribute to congestion on the SPP or the Joint Parties' systems is inefficient. To reduce these inefficiencies, we recommend MISO explore better coordination and settlements on the constraints in adjacent areas that are affected by the transfers. This would increase MISO's ability to transfer power while reducing the congestion effects on its neighbors.

Actual flows on the RDT averaged 1108 MW in the South to North direction in 2024, while flows in the North to South direction were generally correlated with wind output. Until recently, all wind resources in MISO were in the Midwest region and the vast majority of wind resources still are, so when MISO experiences high wind, the RDT flows tend to be in the North to South direction. Conversely, when wind falls sharply, flows tend to reverse to the South to North direction. The ability of the MISO market to shift the quantity and direction of flows by more than 5,000 MW provides tremendous value to the customers in both regions.

F. Real-Time Dispatch Performance

MISO issues dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. Good performance of MISO's generators is essential to efficiently managing congestion and maintaining reliability in MISO. Therefore, it is critical that MISO's markets provide adequate incentives for its generators to perform well in following MISO's dispatch instructions. Failing to meet the dispatch instruction is known as "dragging", and it can be measured in each 5-minute interval or summed over a longer period (e.g., 60-minutes). Table 5 shows the average 5-minute and 60-minute average hourly dragging in recent years in all hours and in hours when generation must ramp up or down rapidly in the morning and evening.

Table 5: Average Five-Minute and Sixty-Minute Dragging
2020–2024

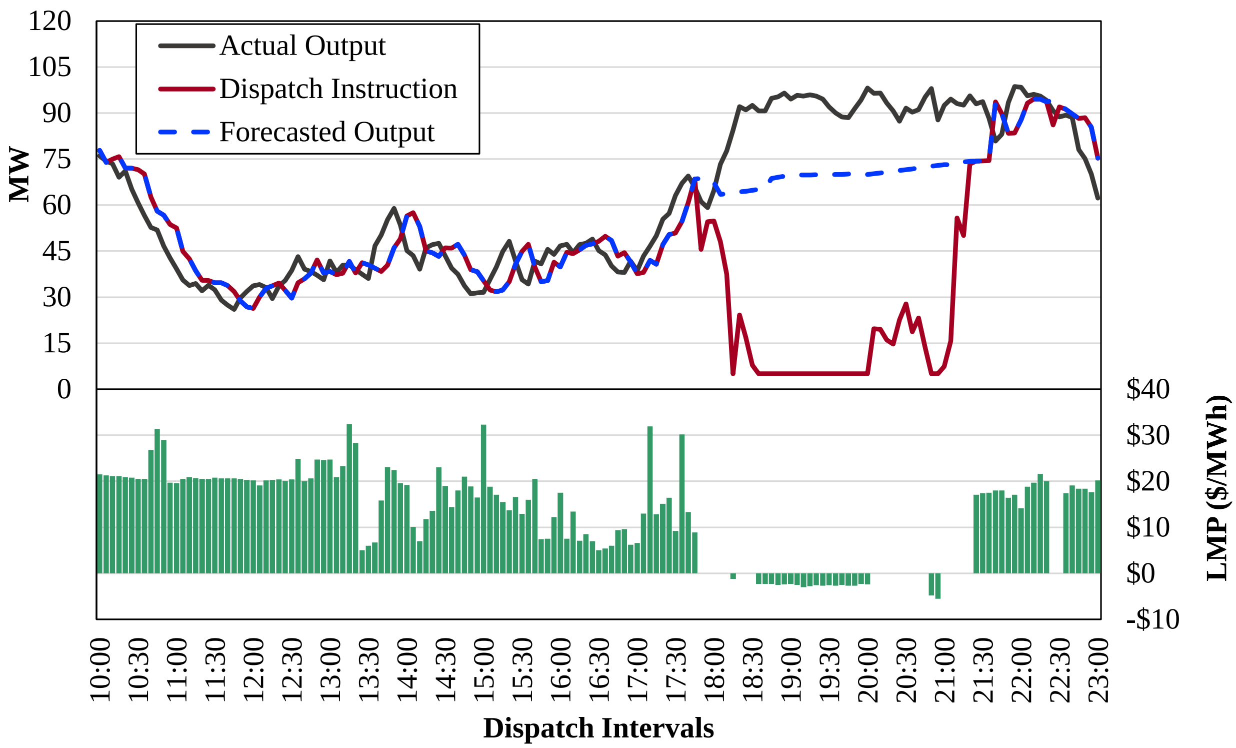
	5-min Dragging		60-min Dragging		Worst 10%	
	Ramp Hours	All Hours	Ramp Hours	All Hours	Ramp Hours	All Hours
2024	474	464	836	777	1,224	1,133
2023	480	471	833	763	1,159	1,098
2022	637	660	1,049	1,009	1,341	1,257
2021	611	629	956	908	1,338	1,290
2020	573	563	957	862	1,289	1,193

Table 5 shows that the 60-minute dragging in all hours increased five percent from 2023 to 2024. Dragging raises a substantial concern because capacity on resources that are not following dispatch instructions is effectively unavailable to MISO. Some of these 60-minute deviations may indicate units that are derated and physically incapable of increasing their output. Because participants are obligated to report derates under the Tariff, we have referred the most significant "inferred derates" to FERC enforcement. Additionally, such conduct can qualify as physical withholding when no physical cause for the derate exists.

The failure to follow dispatch instructions generally creates the greatest adverse effects when the resource affects a binding transmission constraint. In this case, the real-time market dispatch will produce dispatch instructions and prices that assume the resource will follow the dispatch instructions. Figure 21 shows an example of a wind resource dispatched from 10 a.m. to 11 p.m., along with the forecasted output, dispatch instruction, and the LMP at the resource's location. The forecast matches the dispatch instruction whenever the unit is not curtailed because: (a) the forecast is assumed to be the unit's economic maximum level and (b) the unit is offered at a negative price. Since MISO uses a persistence forecast, the forecast always equals the observed output of the unit roughly 10 minutes earlier, except when the unit is curtailed.

From approximately 6:00 p.m. to 9:15 p.m., the real-time dispatch model attempted to curtail this unit and generally set prices at zero or at a slightly negative price. These prices reflect the substantial congestion that the dispatch model recognized assuming this unit will follow the dispatch instruction. The congestion was more severe because the excess output (deviation) from this unit increased the flow on the constraint by as much as 38 MW, violating the modeled limit for the constraint by as much as nine percent.

Figure 21: Example of Wind Resource Failing to Follow Dispatch Instructions



These findings indicate the importance of improving generators' incentives to follow dispatch instructions and update to resources' real-time offers in a timely manner. We discuss below our recommendation for improving these incentives for units that overload transmission constraints.

Aligning Uninstructed Deviation Penalties with Congestion Impact

Current settlement rules are insufficient for generation deviations outside the uninstructed deviation (UD) tolerance bands and deviations that persist for less than 20 minutes are exempted from any financial penalty. The most significant penalty is the excessive energy price, paid at the lower of LMP and as-offered cost on excessive energy volumes. This provides a very weak incentive, particularly to renewable resources, which often set prices at their cost when curtailed. In these cases, the renewable resource is financially indifferent between following dispatch and producing excessive energy. This indifference is especially harmful when the excessive energy causes transmission overloads that are difficult to manage. We have observed operators taking expensive actions to manage the transmission system in response to wind resources that are not following their dispatch.

This concern is bound to grow as more intermittent resources enter the system, so we are recommending an improvement to the penalty structure that would be based on the marginal congestion component (MCC) of the resources' LMP. For excessive or deficient energy that loads a constraint, we recommend that MISO impose a penalty equal to an escalating share of the MCC of its price beginning with 25 percent in the first interval and rising to 100 percent by the fourth interval. This MCC-based penalty is correlated with the severity of congestion impacted by the deviation. The table below shows how this penalty would have affected several types of units in 2023.

Table 6: Proposed Uninstructed Deviation Penalties and Effective Rate in 2023

		Avg. Deviation Penalty ($/MWh)		Average Penalty ($/MWh of Output)	
Unit Type	**Total Penalty**	**Excessive**	**Deficient**	**Excessive**	**Deficient**
Gas Turbine	$141,457	$3.89	$2.13	$0.001	$0.001
Coal	$459,125	$3.24	$3.66	$0.001	$0.002
Gas CC	$272,980	$4.06	$2.80	$0.001	$0.001
Other	$105,525	$2.17	$6.10	$0.000	$0.001
Solar	$32,435	$7.38	$0.27	$0.005	$0.000
Wind	$819,298	$25.72	$0.96	$0.009	$0.000

There are several key takeaways from this table:

- The average penalty rate per MWh of output is extremely low at less than $0.01 for most generators. Resources that follow dispatch instructions reasonably well should be minimally impacted by this proposal.
- The deviation penalty rate is material, which should promote better performance.
- The excessive energy penalty rates are largest for wind resources even though most are exempt from UD penalties except when curtailed. Because they have such fast ramp rates, failure to follow dispatch can result in large deviations that cause serious constraint violations with little warning.

Hence, the proposed penalties will improve dispatch incentives for all resources, and particularly for those whose deviations cause the most serious reliability concerns.

Additionally, MISO is implementing a dispatch flag for intermittent resources that will clearly indicate when resources are contributing to loading a binding constraint. This penalty and the development of other settlement rules associated with this flag should be prioritized to improve MISO's operational control of the system through the real-time market.

Dispatch Operations: Offset Parameter

The offset parameter is a quantity chosen by the MISO real-time operators to adjust the modeled load to be served by the unit dispatch model. A positive offset value is added to the short-term load forecast to cause an increase in the generation output, while a negative offset decreases the load and the corresponding dispatch instructions. Offset values may be needed for many reasons, including: a) generator outages that are not yet recognized by the model; b) generator deviations (producing more or less than MISO's dispatch instructions); c) wind output that is over or under-forecasted in aggregate; or d) operators believing the short-term load forecast is over or under-forecasted.

Large changes in offset values increase price volatility. This is not surprising because ramp capability—the ability of the system to quickly change output—is often limited, so large changes in the offset can lead to sharp changes in prices. Conversely, offset reductions or lower than optimal offset values sometimes mute legitimate shortage pricing. We have identified a number of events in which sub-optimal offset values led to inefficient real-time prices. We are working with MISO to improve its procedures for setting more optimal offset values.

G. Coal Resource Operations

In the summer of 2021, as natural gas and energy prices rose during the summer months, the economic operating margins of MISO's coal-fired resources rose substantially and caused them to operate at higher capacity factors. However, multiple coal-fired resources began to experience COVID-related supply chain issues, transportation limitations, and shortages of reagents. These limitations led to coal conservation strategies that substantially reduced their output beginning in the fall of 2021 and lasted through the end of 2022. By late 2023, coal supply constraints had fully eased as railroads were able to support adequate coal deliveries in MISO.

In Table 7, we summarize our analysis of coal resource operations, including how they are started and how profitably they operated. Because many of the regulated utilities operate differently than unregulated merchant generators, the table shows our results for them separately.

Table 7: Coal-Fired Resource Operation and Profitability
2019–2024

	2019-2022			2023			2024		
	Annual Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)
Regulated Utilities	1716		**$14.64**	1549		**$5.81**	1428		**$8.01**
Profitable Starts	1485	84%		1336	86%		1214	85%	
Offered Economically	*730*	*42%*		*684*	*44%*		*672*	*47%*	
Must-Run and profitable	*756*	*42%*		*652*	*42%*		*542*	*38%*	
Unprofitable (Must Run)	231	16%		213	14%		214	15%	
Merchants	133		**$19.66**	42		**$6.98**	39		**$7.50**
Profitable Starts	133	100%		41	98%		35	90%	
Offered Economically	*133*	*99%*		*39*	*93%*		*29*	*74%*	
Must-Run and profitable	*1*	*1%*		*2*	*5%*		*6*	*15%*	
Unprofitable (Must Run)	0	0%		1	2%		4	10%	

Table 7 shows that falling natural gas and energy prices in 2024 caused coal resources to have a slightly lower share of profitable starts than in 2023. Their net revenues rose to roughly $8 per MWh on average – higher than the average net revenues in 2023 but much lower than in 2022 and prior years. MISO's regulated utilities often continue to operate their units as "must-run," running them regardless of the price. In contrast, MISO's unregulated generators offered economically 74 percent of hours in 2024 and were profitable in 90 percent of their run hours.

H. Wind Generation

As discussed in Section III.B, wind capacity is continuing to grow in MISO. Accounting for almost 30 GW of MISO's installed capacity, wind resources produced 15 percent of all energy in MISO in 2024. Section III.B also discusses the long-term challenges this will present and the market enhancements that we recommend. This subsection describes key trends related to wind output, wind scheduling, and wind forecasting. These results are summarized in Table 8.

Table 8: Day-Ahead and Real-Time Wind Generation

	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.
2024	30,784	11.2	10.1	-10.0	13.5	8.4	11.8	23.1	18.2	21.9	10.9%	13.7%
*%**	*3%*	*8%*	*10%*		*4%*	*18%*	*5%*	*6%*	*2%*	*2%*		
2023	29,830	10.4	9.2	-12.0	13.0	7.1	11.2	21.8	17.8	21.4	4.0%	8.1%
2022	29,109	11.3	10.1	-10.8	13.7	8.4	11.9	21.6	18.0	21.6	2.3%	6.6%
2021	26,862	9.2	8.0	-13.0	10.0	7.0	10.7	18.6	15.3	19.9	-3.3%	6.7%

Note 1: %* Change between 2023 and 2024.

Wind Output Trends

Average wind output increased eight percent from 2023 after a decline in 2023. Before 2023, wind output grew rapidly, having increased 74 percent between 2019 and 2022. The increase in 2024 is likely due to the absence of the El Nino climate patterns, which tend to cause lower prevailing winds, that occurred during the summer of 2023. The table also reveals the seasonal wind output patterns, with output decreasing in summer months and at its highest levels in the spring and fall seasons. We expect the trend of increasing output to continue in 2025 and beyond given the new wind projects in MISO's interconnection queue and the state and federal incentives available to wind resources.

Wind Forecasting

The increasing penetration of wind resources has increased the operational challenges associated with managing the ramp demands resulting from the wind output fluctuations that are described in Section III.B. The accuracy of the wind forecasts is a key issue in managing these challenges. Wind forecasts are produced and used in two key timeframes, which we discuss below:

- Forward forecasts: produced from day-ahead up to the operating hour, which are based on wind speed forecasts and other factors; and
- Real-time dispatch forecasts: produced roughly five minutes before the next dispatch interval and generally based on the current wind output (i.e., a "persistence" forecast).

Forward wind forecasting: As Table 8 shows, the size of the two-hour ahead forecast errors has been increasing in recent years. The table shows that the typical forecast error in 2024 was almost fourteen percent, up from eight percent in 2023. On a high-wind day, this error would approach 2000 MW, which happened in 42 percent of hours in 2024, and we have seen the two-hour ahead forecast error exceeding 10,000 MW during the last year. This can lead to supply shortages and overloads of individual transmission constraints and the RDT interface. Therefore, it is important to continue to evaluate the causes of relatively large errors and seek improvements to the forecasting methodologies and inputs.

Real-time dispatch forecasts: These forecasts are the most important forecasts to be accurate since they are used to establish wind resources' economic maximums in the real-time market. Because wind units offer at prices lower than other units, the forecasted output also typically matches the dispatch instruction, absent congestion. Importantly, if this forecast is not accurate, the dispatch model will not accurately be modeling and controling the flows on transmission constraints affected by the wind resources. This has led to frequent transmission violations and challenges in managing the flows over these constraints.

MISO has improved the real-time forecasts by reducing the time lag between the most recent output observation and the real-time dispatch model run. Further improvements could likely be achieved by modifying the persistence algorithm to account for how the wind resources have been moving leading up to the most recent observations and further reducing the time lags by bringing the real-time forecasts in-house. MISO made progress in these areas in early 2025.

Wind Scheduling in the Day-Ahead Market

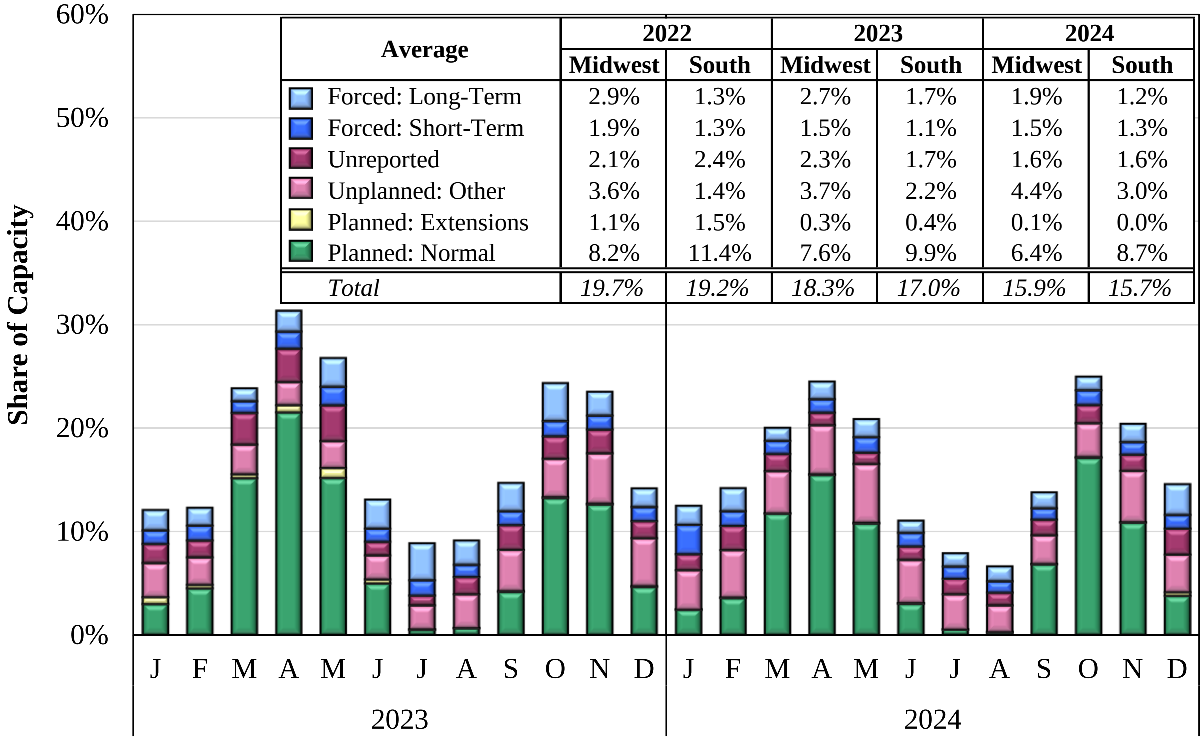
Table 8 shows that wind suppliers generally schedule less output in the day-ahead market than they actually produce in real time. Hourly under-scheduling of wind averaged roughly 1,100 MW in 2023. This can be attributed to suppliers' contracts and financial risks related to RSG cost allocations when day-ahead wind output is over scheduled. Under-scheduling can create price convergence issues and uncertainty regarding the need to commit other resources, which is partially addressed by net virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers.

Since the most significant effect of under-scheduling wind in the day-ahead market is its effects on the transmission flows and associated congestion, we evaluated the extent to which virtual transactions offset the flow effects of wind under-scheduling. In evaluating these patterns, we found that virtual suppliers made approximately $110 million on a total of 722 wind-impacted constraints, with over one third of the profits occurring on the top 10 constraints. The virtual activity serves a valuable role in facilitating more efficient day-ahead scheduling.

I. Outage Scheduling

Coordination of planned outages is essential to ensure that enough capacity is available if contingencies or higher than expected load occurs. MISO approves planned outages that do not violate reliability criteria, but it otherwise does not coordinate outages, which raises significant economic concerns and reliability risks. Figure 22 shows outage rates in MISO Midwest and MISO South from 2022 to 2024.

Figure 22: Generation Outages
2022–2024



Average	2022		2023		2024	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	2.9%	1.3%	2.7%	1.7%	1.9%	1.2%
Forced: Short-Term	1.9%	1.3%	1.5%	1.1%	1.5%	1.3%
Unreported	2.1%	2.4%	2.3%	1.7%	1.6%	1.6%
Unplanned: Other	3.6%	1.4%	3.7%	2.2%	4.4%	3.0%
Planned: Extensions	1.1%	1.5%	0.3%	0.4%	0.1%	0.0%
Planned: Normal	8.2%	11.4%	7.6%	9.9%	6.4%	8.7%
Total	*19.7%*	*19.2%*	*18.3%*	*17.0%*	*15.9%*	*15.7%*

Figure 22 shows that outage rates in 2024 were lower than in 2023. As in prior years, true planned outages were relatively low for most of the summer. While the overall level of outages does not raise concerns, poorly coordinated outages do frequently raise concerns in local areas. In our *2016 State of the Market Report*, we recommended that MISO enhance its transmission and generation planned outage approval authority (see Recommendation 2016-3). We continue to believe that it is important for MISO to acquire the authority to deny or postpone outage requests that will create severe congestion or regional shortages. This is particularly important as many planned outages are scheduled or extended with very little advance notice.

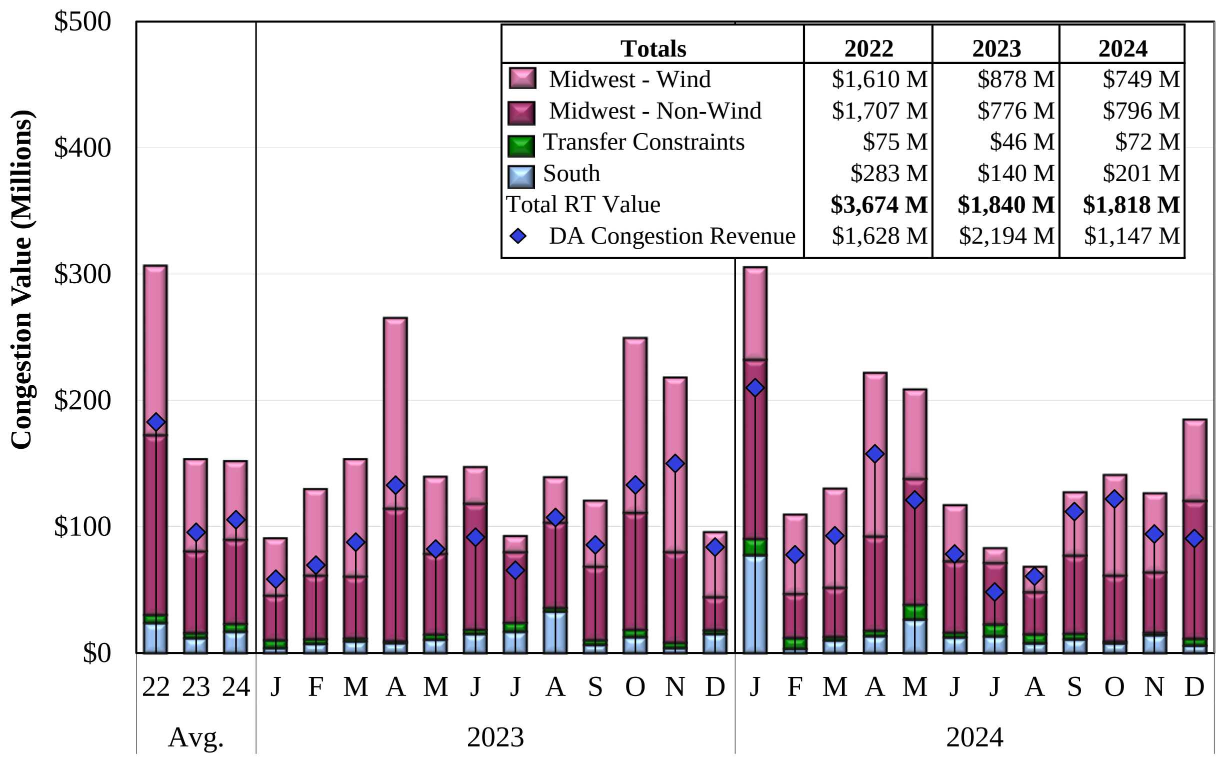
V. Transmission Congestion and FTR Markets

The MISO markets manage power flows over the network to avoid violating transmission constraints by modifying resources' dispatch levels. Transmission congestion arises when network constraints prevent MISO from dispatching the lowest-cost resources to meet demand. The resulting "out-of-merit" costs are reflected in the marginal congestion component (MCC) of the LMPs (one of three LMP components). The MCCs raise LMPs in "congested" areas where generation relieves the constraints and lower LMPs where generation loads the constraints. These create valuable locational price signals that reflect the efficient dispatch of resources in the short term and help facilitate efficient investment decisions in the long term.

A. Real-Time Value of Congestion in 2024

The value of real-time congestion is calculated as the product of real-time physical flow over each constraint and the economic value of the constraint (i.e., the "shadow price" – the production cost savings from relieving the constraint by one MW). This is the value of congestion that occurs as MISO dispatches its system. Figure 23 shows the monthly real-time congestion value over the past two years along with day-ahead congestion revenues.

Figure 23: Value of Real-Time Congestion
2023–2024

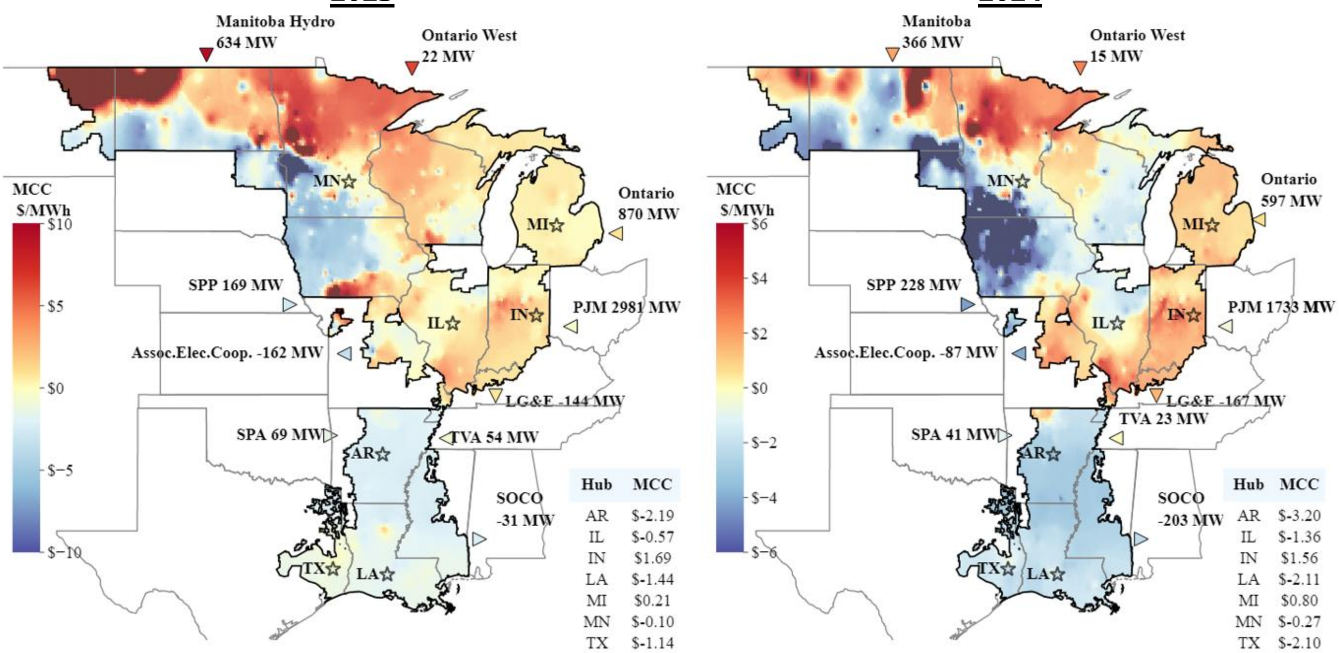


The total value of real-time congestion was $1.8 billion in 2024, virtually unchanged from 2023. A significant share of the total congestion occurred during Winter Storm Heather in January as well as severe congestion that occurred in May caused by storm-related outages. Wind-driven congestion constituted a slightly lower share of congestion than it did in 2023 (at roughly 41 percent) partly because operators' manual interventions to manage this congestion often prevented it from being fully priced in the market. We discuss these operator actions in more detail later in this section. Continued expansion of nearby wind resources in SPP and PJM, as well as retirements of dispatchable resources is likely to increase wind-related congestion in future years.

Figure 24 shows the locational differences in the average MCCs of MISO's LMPs in 2023 and 2024. Warmer colors indicate locations where the MCCs are positive and increase LMPs, while cooler colors indicate locations with negative MCCs that lower LMPs. Generally, power flows across MISO from the cooler-colored areas to the warmer-colored areas.

Figure 24: Average Real-Time Congestion Components in MISO's LMPs

2023 **2024**



This figure shows changes in congestion patterns in the Midwest region. A drought in Manitoba began in 2023 that limited hydroelectric generation in Manitoba and caused imports to fall. Drought conditions persisted until the fall of 2024, contributing to slightly lower average hourly imports. In addition, SPP constraints that were coordinated with MISO caused severe congestion in the Northwestern part of the footprint in 2023. In 2024, SPP implemented a "Remedial Action Scheme" for the most congested flowgate in this area, which reduced congestion on the facility by 78 percent year over year.

Finally, the map shows evidence of the transfer constraint between the Midwest and South, which bound in more than one quarter of real-time intervals and resulted in separation of subregional prices of roughly $3 per MWh.

B. Congestion over the Transfer Constraint

The Regional Directional Transfer (RDT) is a contractual constraint between MISO's Midwest and South subregions, limiting physical flows to 3,000 MW Midwest-to-South and 2,500 MW South-to-Midwest. In general, unusually high renewable output in the Midwest will cause north-to-south flows over the RTD while unusually low output will result in south-to-north flows over the RDT. Because unmodeled physical flows over the RDT can cause the flows to exceed the contract limits.[19] MISO derates the RDT limit to 92 percent of the contract limit by default and often by more. These derates can produce widespread price effects throughout each subregion.

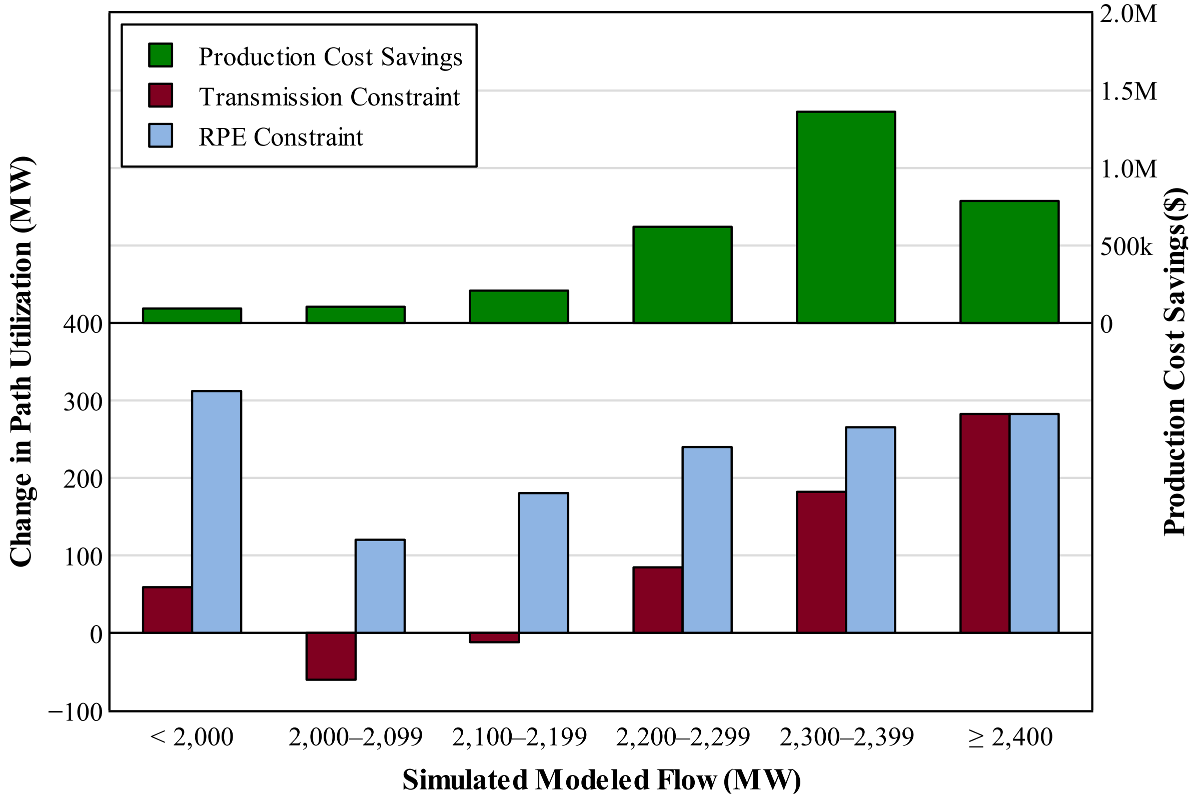
Currently, MISO uses a two-step TCDC for the RDT with a lower step at $40 per MWh at the limit and the second step at $500 per MWh starting at 102 percent of the modeled limit. Hence, when the RDT is in violation by more than 2 percent of the limit, the prices throughout each subregion will move to establish a $500 spread between the Midwest and the South subregions. MISO also models a Reserve Procurement Enhancement (RPE) constraint that limits flows between subregions after a supply-side contingency and has a single demand value of $200 per MWh. Our evaluation of these transfer constraints reveals the following:

- The ability of the dispatch to change the magnitude and direction of the flows over the transfer constraint provides a valuable capability for MISO to accommodate large and rapid changes in the intermittent renewable output in the Midwest.
- RDT deratings cause MISO to utilize only 84 percent of the RDT when in binds.
- When the transfer constraints are violated, it often produces subregion-wide price spreads of $700 because the demand curve values for the RDT ($500) and the RPE ($200) apply additively, which was unintended. These violations should be priced at $500 per MWh.

To address these concerns, we recommend that MISO modify the RDT Transmission Constraint Demand Curve (TCDC) by adding lower-valued steps, beginning at 80 percent of the contract limit, and raising the energy plus STR limit to align with the highest penalty step on the TCDC. These demand curve adjustments will increase RDT utilization when the value of subregional transfers is high and reduce the burden on MISO operators to constantly monitor and adjust the RDT limit in the real-time market. In Figure 25, we show the production cost savings resulting from modifying the RDT demand curve, along with the increased utilization of the contract path from derates that were no longer required to avoid contract violations.

19 Unmodeled physical flows are caused by regulation deployments and generators or load deviations.

Figure 25: Increased Contract Path Utilization and Production Cost Savings
Proposed TCDC, 2024



This analysis shows a $3.2 million reduction in total production costs, as well as an 8 MW increase in average utilization of the RDT transmission constraint and 183 MW for the RPE constraint. The largest source of cost savings is the additional transfer capability above 2,300 MW, which the proposed TCDC unlocks by eliminating the need for operators to derate to that level by default. Increased RPE constraint utilization yields additional savings by reducing demand for Short Term Reserves, allowing generators in the unconstrained region to hold less headroom for STR and produce more energy. Overall, the proposed TCDC is ensuring contract compliance while allowing the cheapest available generation to meet STR and energy demands, lowering the System Marginal Price (SMP) by almost $4 per MWh.

C. Day-Ahead Congestion and FTR Funding

MISO's day-ahead energy market is designed to send accurate and transparent locational prices that reflect energy costs, congestion, and losses on the network. MISO collects congestion revenue in the day-ahead market from load based on the differences in the congestion component of the LMPs at locations where energy is produced and consumed. The resulting congestion revenue is paid to holders of Financial Transmission Rights (FTRs), which are economic property rights to power flows over particular elements of the transmission system.

A large share of the value of these rights is allocated to participants based on historical firm use of the transmission network. The rights to the remaining transmission capability are sold in the FTR market, with this revenue contributing to the recovery of the costs of the network. FTRs provide a means for market participants to hedge day-ahead congestion costs. If the FTRs issued by MISO are physically feasible, meaning that network flows implied by all FTRs sold do not exceed the network capability in the day-ahead market, MISO will always collect enough congestion revenue through its day-ahead market to “fully fund” the FTR entitlements.

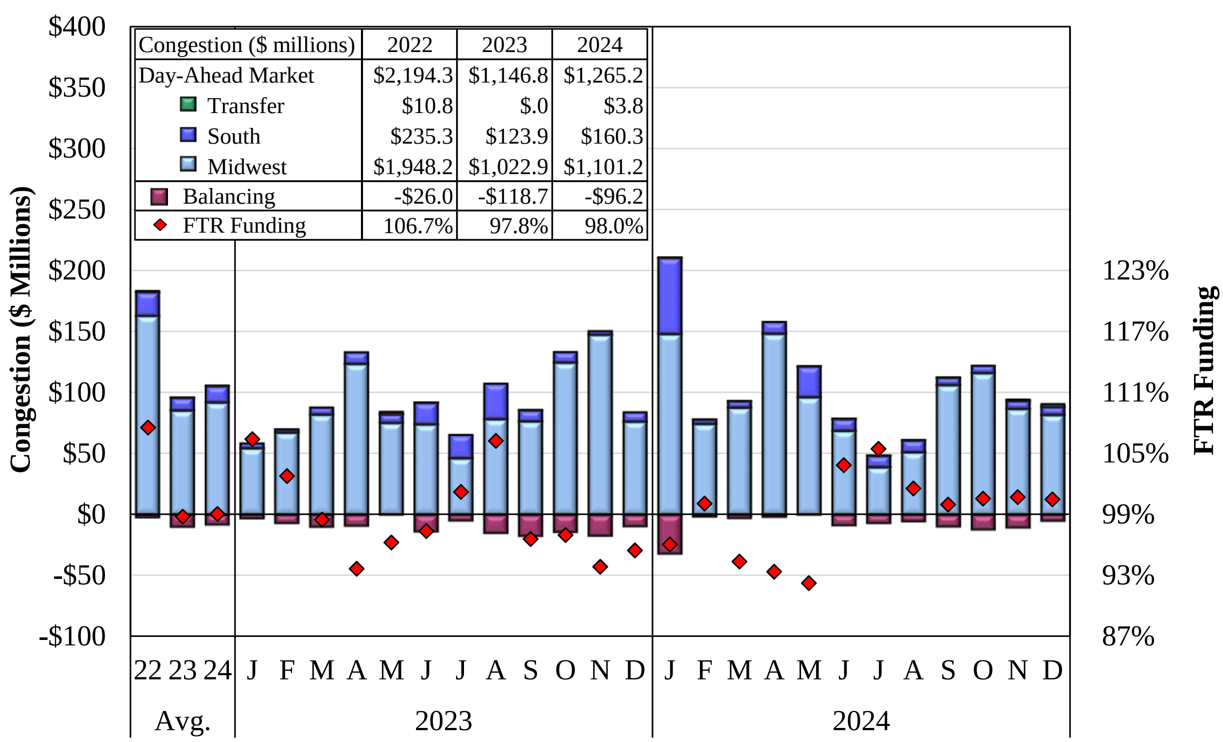
In addition to summarizing the day-ahead congestion, this subsection evaluates two key market outcomes that reveal how well the network is modeled in the day-ahead and FTR markets:

- *FTR Funding*: If MISO does not collect enough congestion in the day-ahead market to satisfy the FTR entitlements, FTR funding will be less than 100 percent, indicating that MISO issued more FTRs than the day-ahead network model could accommodate; and
- *Balancing Congestion*: If day-ahead schedules are not feasible in the real-time market, congestion will occur in real time to “buy back” the day-ahead flows. The cost of doing so is uplifted to MISO customers as “balancing congestion”.

Day-Ahead Congestion Costs

Figure 26 below summarizes the day-ahead congestion by region and between regions, balancing congestion incurred in real time, and the FTR funding levels from 2022 to 2024.

Figure 26: Day-Ahead and Balancing Congestion and FTR Funding
2022–2024



Day-ahead congestion costs increased by 10 percent to $1.3 billion in 2024, which was 70 percent of the value of real-time congestion on the system. MISO does not collect revenues associated with the full value of real-time congestion because a large amount of "loop flows" are caused by entities that do not settle with MISO, and MISO grants flow entitlements on MISO's system to SPP and PJM that do not pay for congestion up to their entitlement levels.

Figure 26 shows that day-ahead congestion rose in 2024, and this was largely driven by day-ahead constraint violations that occurred during Winter Storm Heather in January. It also shows that while FTRs were more fully funded than in 2023, the FTRs were still not fully funded. The magnitude of balancing congestion decreased year over year, although it was still relatively high. We discuss these two classes of results in the following subsections.

FTR Surpluses and Shortfalls

Overfunding and underfunding of FTRs are caused by discrepancies between the modeling of transmission constraints and outages in the FTR auctions and the day-ahead market. For example, if the flow on a binding day-ahead market constraint is below the flow scheduled in the FTR market, a congestion shortfall will occur. Conversely, a surplus will result when flow on a binding day-ahead constraint is higher than the flow sold in the FTR market. Funding surpluses also include residual revenues from the FTR auctions.

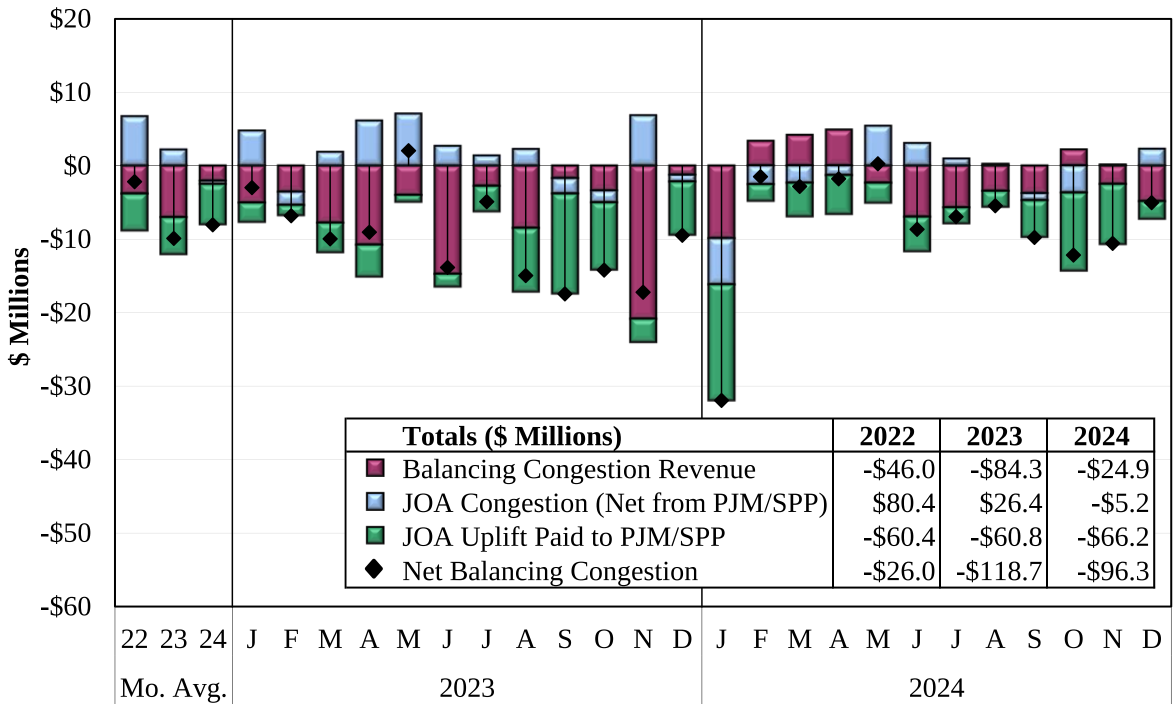
In 2024, day-ahead congestion revenues were short of FTR obligations by two percent, despite changes in the modeling of outages and transmission capability in recent years to help ensure full funding of the FTRs. Late-reported outages and M2M coordination issues contributed to the shortfalls in 2024. During the winter quarter, roughly half of the $32 million FTR shortfall was caused by a late-reported transmission outage requested in December 2023 to begin in January. However, FTRs over the RDT are often overfunded because they can bind in both directions. This bi-directionality causes FTR paths across the transfer constraint to be undersubscribed and to generate substantial surpluses when the RDT binds in the day-ahead market.

Balancing Congestion

Balancing congestion shortfalls (negative balancing congestion revenue) is the cost of re-dispatching generation to reduce real-time flows on a constraint scheduled at a higher level of flow in the day-ahead market. Conversely, positive balancing congestion occurs when real-time constraints bind at flow levels higher than those scheduled in the day-ahead market.

Large amounts of negative balancing congestion costs typically indicate real-time transmission outages or other transmission limit reductions, loop flows that were not fully anticipated day-ahead, or real-time constraints binding that were not modeled in the day-ahead market. Net negative balancing congestion is uplifted to MISO's load and exports on a pro-rata basis. While real-time forced outages and derates cannot be eliminated, persistent high levels of negative balancing congestion may indicate day-ahead modeling issues. Accordingly, RTOs should seek to maximize consistency between the day-ahead and real-time market models. Figure 27 shows the monthly balancing congestion costs incurred by MISO, which include the Joint Operating Agreement (JOA) payments to and received from SPP and PJM.

Figure 27: Balancing Congestion Revenues and Costs
2022–2024



Totals ($ Millions)	2022	2023	2024
Balancing Congestion Revenue	-$46.0	-$84.3	-$24.9
JOA Congestion (Net from PJM/SPP)	$80.4	$26.4	-$5.2
JOA Uplift Paid to PJM/SPP	-$60.4	-$60.8	-$66.2
Net Balancing Congestion	-$26.0	-$118.7	-$96.3

The magnitude of net balancing congestion fell in 2024 to negative $96.2 million:

- The 71 percent reduction in the balancing congestion revenue shortfall compared to 2023 suggests decreased unanticipated congestion in the real-time market.
- Net JOA congestion payments to PJM and SPP were $5.3 million in 2024, compared to net JOA congestion payments from PJM and SPP of $27.4 million in 2023.
- MISO's JOA costs uplifted to SPP and PJM increased by nine percent to $66.2 million in 2024, even though overall system congestion was comparable to 2024.

FTR Market Performance

FTRs represent forward entitlements to day-ahead congestion and are instrumental for allocating the value of the transmission system. Because transmission customers pay for the embedded costs of the system, they should be entitled to its economic property rights. This is accomplished by allocating Auction Revenue Rights (ARRs) to transmission customers based on their network load and resources. ARRs give customers the right to receive the FTR auction revenues from the sale of the ARRs or to convert their ARRs into FTRs to receive day-ahead congestion revenues.

FTR markets perform well when they establish FTR prices that accurately reflect the expected value of day-ahead congestion, resulting in low FTR profits for the buyers (day-ahead congestion payments minus the FTR price). Even if the FTR prices represent a reasonable expectation of congestion, a variety of factors may still cause actual congestion to be much higher or lower than FTR auction values. MISO currently runs two types of FTR auctions:

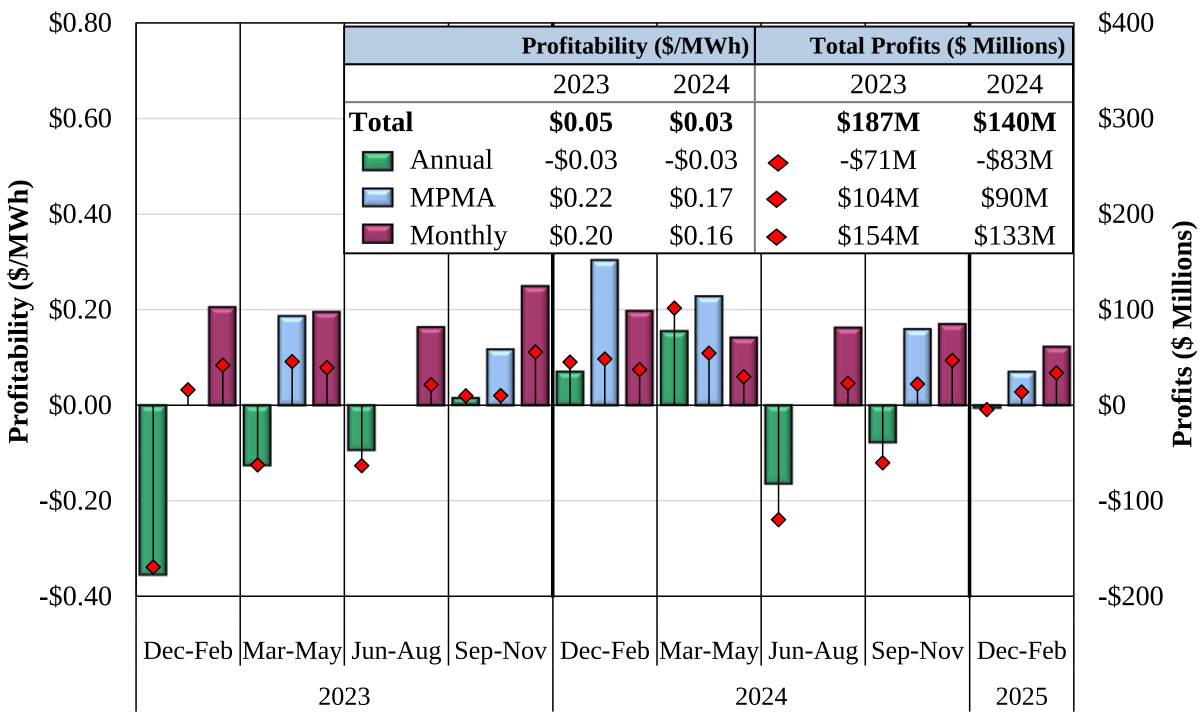
- An annual auction from June to May that includes seasonal and peak/off-peak resolution of bids, offers, and awards; and
- A Multi-Period Monthly Auction (MPMA) that yields monthly and seasonal peak/off-peak awards and facilitates FTR trading for future periods in the current year.

FTR Market Profitability

Figure 28 shows our evaluation of the profitability of FTRs in these auctions by showing the seasonal profits for FTRs sold in each market in the bars. The profit margin for each class of FTRs is shown in red diamonds. For comparison purposes, the profitability of monthly FTRs purchased in the MPMA are aggregated seasonally in this figure.

Annual FTR Profitability. Figure 28 shows that FTRs issued through the annual FTR auction were unprofitable overall with profitability of -$0.03 per MWh. Losses are most common in the annual auction because it occurs furthest from the horizon, so congestion is more uncertain, and some conversions of ARRs to FTRs occur at prices that do not reflect expected congestion.

Figure 28: FTR Profits and Profitability
2023–2024

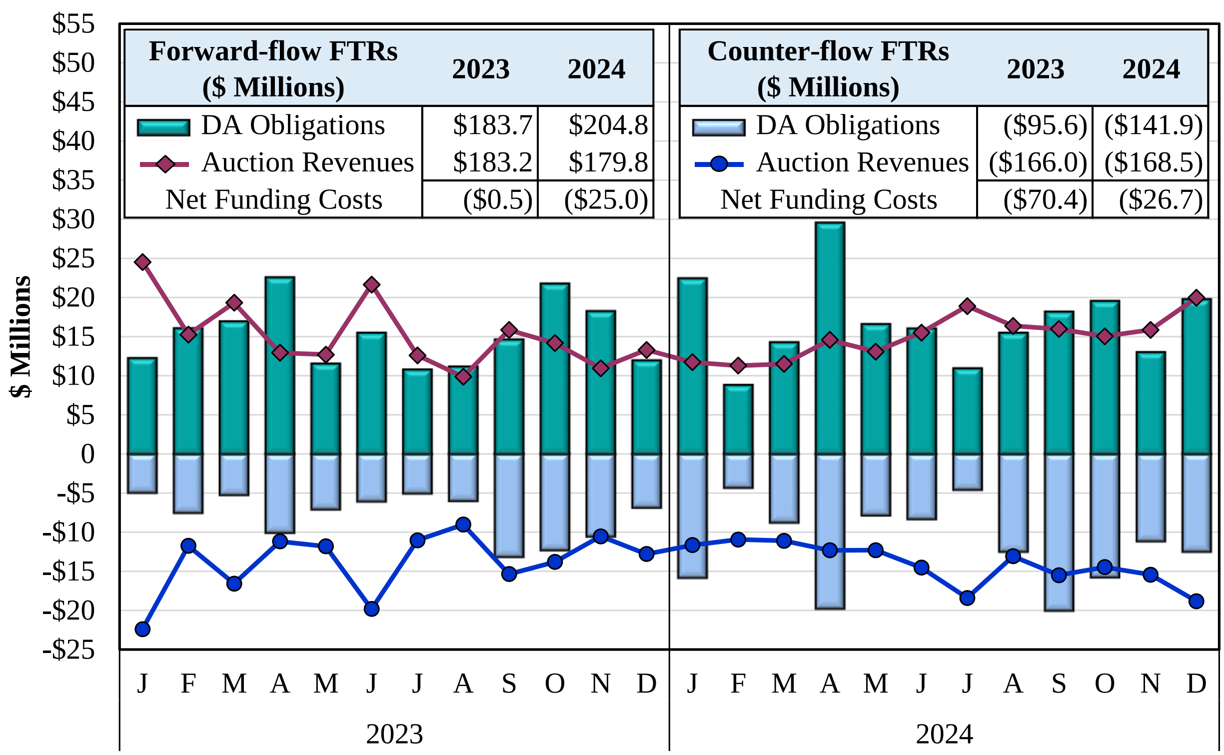


FTR Profitability in the MPMA and Monthly Auction. Figure 28 shows that the FTRs purchased in the MPMA and prompt month auction continued to be profitable, but profitability was down by 20 percent for FTRs purchased from the MPMA and 35 percent for FTRs purchased from the prompt month auction from 2023. In general, the MPMA and monthly markets should produce prices that are more in line with anticipated congestion because they are cleared much closer to the operating timeframe when better information is available to forecast congestion.

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure 29 compares the auction revenues from the MPMA prompt month (the first full month after the auction) to the day-ahead FTR obligations associated with the FTRs sold. The figure separately shows forward-flow and counter-flow FTRs. The net funding costs shown in the inset tables represent the difference between the auction revenues and the day-ahead obligations. A negative value indicates that MISO sold forward-flow FTRs at a price less than their ultimate value or bought counter-flow FTRs at a price greater than their ultimate value.

The analysis shows that the discount in the sales of forward-flow FTRs rose in 2024, increasing the net funding costs (i.e., profits from these FTRs) from $0.5 million to $25 million. These results indicate that the market expectations of congestion were relatively accurate on average in most of the prompt months, whereas unforeseeable events like Winter Storm Heather in January and storm-related congestion in May led to unexpected increases in day-ahead congestion that produced significant profits for forward-flow FTRs in those months.

Figure 29: Prompt-Month MPMA FTR Profitability
2023–2024



In addition to selling forward-flow FTRs in the MPMA FTR auction, MISO often buys back capability on oversold transmission paths by selling counter-flow FTRs (i.e., negatively priced FTRs). In essence, MISO is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on a constraint. Net funding deficits for counter-flow FTRs, although 62 percent lower than the deficits in 2023, were significant in 2024, indicating that MISO substantially overpaid for these FTRs compared to the day-ahead congestion value on average. However, the auction revenues for some months, such as August and October, were well-aligned with the value of the counter-flow obligation.

These results indicate that the MPMA lacks the liquidity needed to erase the differences between FTR prices and congestion values. Barriers to participation should be identified and eliminated, which should improve convergence between the auction revenues and the associated day-ahead FTR obligations. If such improvements cannot be identified, it may be beneficial for MISO to examine its auction processes to determine whether to establish price-based limits on the sale of forward or counterflow FTRs.

Improving the Performance of FTR Markets

Efficient FTR markets will set prices that reflect an accurate expectation of day-ahead congestion. The results above show that the FTR markets have not always performed well in this regard, particularly in the MPMA and monthly auctions. In general, two principal issues affect the performance of the FTR markets:

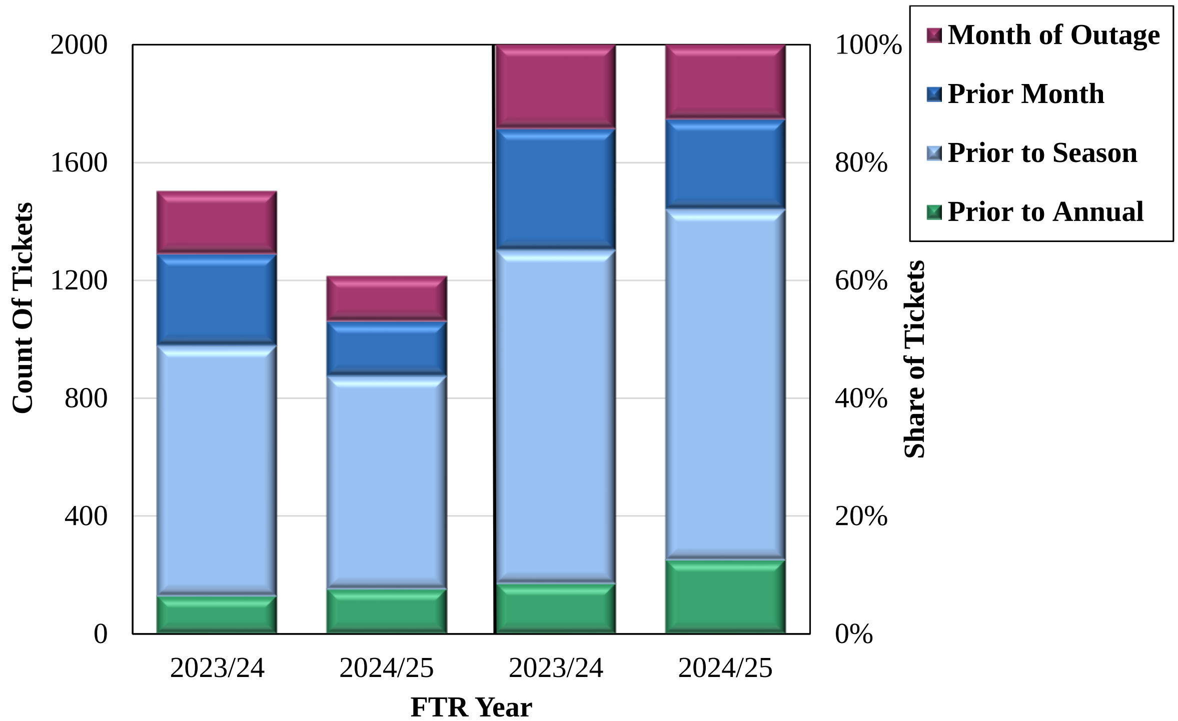
- The accuracy of the network topology, which depends to a large extent on the completeness of the transmission outages that will be occurring; and
- The liquidity of the FTR auctions.

The annual FTR allocation and auction and the MPMA and monthly auctions are affected very differently by these two factors, which we discuss below.

Outage Reporting. Transmission owners are required to schedule outages in MISO's CROW system 12 months in advance. However, we have found that some transmission owners have not complied with this requirement and some outages are not known far in advance. Ultimately, this causes the outages reflected in the annual FTR process to be much less complete than in the timelier auctions. Figure 30 shows the count and shares of planned transmission line outages of 230kV or higher with a duration of 5 days or more that are scheduled prior to (i) the annual auction, (ii) the seasonal MPMA, (iii) the monthly auction, and (iv) after the monthly action.

Figure 30 shows only roughly 10 percent of these planned outages are scheduled in advance of the annual auction. Far less than 10 percent of the planned outages starting in the winter and spring seasons are scheduled prior to the annual auction as those seasons are further in the future than the summer and fall seasons.

Figure 30: CROW Outage Tickets by Creation Date
2023–2025



An additional problem with the outages included in the annual auction is that MISO is compelled to be conservative, so an outage scheduled for longer than 5 days is assumed to occur over the entire season in which it occurs. In contrast, roughly 80 percent of outage tickets were first created in time for the prompt-month auction and 70 percent in advance of the season. Hence, the modeling of the network is much more accurate in the monthly and seasonal timeframes because most planned outages are known by then.

Participation and Liquidity. Although the network topology is much more accurate in the MPMA and monthly auction timeframes, these markets tend to perform worse in setting prices that over time reflect the realized congestion in the day-ahead market. This indicates that these auctions are not sufficiently liquid.

Annual FTR auction prices more closely align with realized congestion than prices in the monthly auctions because of the participation of transmission customers. Currently, the allocation of ARRs only occurs once prior to the Annual FTR Auction. LSEs must decide whether to accept the annual auction revenues or offer to convert their allocations to FTRs. An LSE that specifies a price at which it will accept the FTR auction revenues is effectively submitting a reservation price to sell the FTR. An LSE that chose to self-schedule the conversion of the ARRs to corresponding FTRs is effectively submitting a reservation price of infinity. In both cases, the transmission customers are acting as active sellers of FTRs in the annual auction.

In contrast, no ARRs are allocated after the annual auction so transmission customers have no ability to participate as an FTR seller in the same way as they do in the annual auction. Instead, MISO serves as the seller on the customers' behalf, offering any residual FTR capability at a reservation price of zero. If there is not sufficient liquidity of bidders on an FTR path in this case, the price for the FTRs on this path can be priced far below their value.

In order to facilitate the participation of customers in the seasonal and monthly FTR auctions to increase their liquidity, and to allocate and sell FTRs with a more accurate representation of the transmission network, we recommend that MISO:

- Make a smaller share of the transmission capacity (e.g., one third) available for allocation as ARRs and for sale in the Annual FTR Auction, down from 90 percent currently;
- Release additional transmission capacity to be allocated as ARRs and sold as FTRs in seasonal and monthly FTR auctions (e.g., half of the remaining capacity in each); and
- Modify the ARR allocation process to better align with customers' current use of the system and facilitate allocations of capability that will otherwise be unallocated under the current generation to load nomination process.

By withholding more capacity until the seasonal or monthly auctions, the performance of these markets will improve, and customers are likely to ultimately receive a higher share of the full value of the system. This will also greatly reduce the likelihood that constraints will be oversold in the annual auction, compelling MISO to purchase counter-flow FTRs.

Aggregate Node Definitions Affecting FTR Funding

With the recent influx of large new datacenter loads for cloud computing and crypto-currency mining, the risk has risen sharply that the distribution of load will change significantly in the 16-month span from when the ARR studies are completed to the end of the FTR year. Aggregate definitions applied in the ARR and FTR processes are redefined daily based on the distribution of state-estimated loads from seven days prior. While this daily update process keeps the day-ahead and real-time definitions synchronized and may improve some LSEs' congestion hedges, the revised definitions may vary significantly from the assumptions in the FTR market.

We evaluate the impact on market funding of updates to the composition of aggregate nodes, such as load zones and ARR Zones. This analysis shows a $210 million change in valuation from redefining node aggregates in the day-ahead market after FTR positions were established.

We recommend that MISO consider options to mitigate this risk going forward, such as:

- Incorporating forecasted changes to load aggregates in FTR definitions;
- Using a single FTR aggregate composition for both peak and off-peak periods to better align with the single daily day-ahead/real-time definition;

- Applying the FTR market composition for day-ahead/real-time pricing in cases when FTR positions are much greater in magnitude than actual withdrawals; and
- Discontinuing trading at ARR/load zones where no ARRs are awarded or load is settled.

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

MISO's market-to-market (M2M) processes under Joint Operating Agreements (JOAs) with neighboring RTOs enable the RTOs to efficiently manage constraints affected by both RTOs. The process allows each RTO to utilize re-dispatch from the other RTOs' units to manage its congestion if it is less costly than its own re-dispatch.

Under the M2M process, each RTO is allocated Firm Flow Entitlements (or FFEs) on the coordinated constraint. The process requires the RTOs to calculate the shadow price on the constraint based on their own cost of relieving it and the RTO with the lower cost of relief reduces the flow to help manage the constraint. When the non-monitoring RTO (NMRTO) provides relief and reduces its market flow below its FFE, the monitoring RTO (MRTO) will compensate it for this relief by paying it the marginal value of the relief. Conversely, if the NMRTO's market flow exceeds its FFE, the NMRTO will pay the MRTO for the excess flow times the marginal costs incurred by the MRTO.

Summary of Market-to-Market Settlements

Congestion on M2M constraints increased overall in 2024 with the real-time congestion value on MISO M2M constraints rising 4 percent to total $641 million because of higher average wind output. Congestion on external M2M constraints (those monitored by PJM and SPP) fell by 26 percent in 2024, partly because of a change in the management of a key constraint in SPP that had generated $61 million in congestion in 2023. The congestion value for all external M2M constraints totaled $100 million, which includes only the MISO flows on these constraints so the total value of these constraints for SPP and PJM is much higher.

It is important to note that the congestion value for the M2M constraints is different than the settlement costs incurred by MISO customers. As described above, the settlement costs are determined by each RTO's flows on the M2M constraints relative to their FFEs. Table 9 shows MISO's annual M2M settlements with SPP and PJM over the past two years.

Table 9: M2M Settlements with PJM and SPP ($ Millions)
2023–2024

	PJM	SPP	Total
2024	$40	-$110	-$70
2023	$57	-$87	-$30

Table 9 shows that net payments generally flowed from PJM to MISO because PJM exceeded its FFEs on MISO's system. Thirty-nine percent of PJM's payments to MISO occurred in April and May. During this time, wind generation was high, making it more difficult to manage M2M constraints significantly impacted by wind resources, which have fast ramp rates that create volatility and oscillations in relief request quantities from the NMRTO.

MISO generally makes M2M payments to SPP, partly because SPP enjoys relatively high FFEs on key constraints in both SPP and MISO. For other constraints, some of the differences in SPP's FFE levels can be attributed to differences in the completeness of the historic transmission reservations included in the FFE calculations by SPP versus MISO. A substantial portion of MISO's historic transmission reservations are not included in the FFE calculations. We also question the wisdom of basing FFEs on *reservations* rather than *schedules*. Schedules are generally a fraction of the reservation quantities and schedules more accurately represent the historic use of the system. As wind output along the SPP seam grows and generator retirements reduce MISO's ability to relieve the wind-related constraints, we expect the payments to SPP to continue to grow. Ultimately, the RTOs must reform and update their processes to calculate FFEs as the current process dating back to 2004 is increasingly unreasonable.

Market-to-Market Effectiveness

One metric we use to evaluate the effectiveness of the M2M process is tracking the convergence of the shadow prices of M2M constraints in each market. When the process is working well, the NMRTO will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the marginal cost of the MRTO's relief. Our analysis shows that for the most frequently binding M2M constraints, the M2M process generally contributes to shadow price convergence and lowers the MRTO's shadow price after the M2M process is initiated.

However, we found that on some constraints, shadow prices fail to converge because the MRTO does not request sufficient relief to achieve convergence. This can occur because the current relief request software does not consider the shadow price differences between the RTOs. When the NMRTO's shadow price is sustained at a much lower level, the relief requested should increase to lower congestion costs and accelerate convergence. At other times, the software can request too much relief and cause constraints to bind and unbind in subsequent intervals, which is called "oscillation". To address these issues, we have recommended that MISO base relief requests on the RTOs' respective shadow prices and implement an automated means to control constraint oscillation. In the long term, MISO should use dynamic transmission constraint demand curves to reflect the actual relief provided by the NMRTO in the dispatch of the MRTO.

Evaluation of the Administration of Market-to-Market Coordination

Effective administration of the M2M process is essential because failing to identify or activate a M2M constraint raises two types of concerns:

- *Efficiency concerns*. The savings of coordinating with the NMRTO to relieve the constraint are not achieved and congestion costs are higher than necessary.
- *Equity concerns*. The NMRTO may vastly exceed its firm flow entitlements on the constraint with no compensation to the MRTO.

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

- Failure to test all constraints that might qualify as new M2M constraints;
- Delays in testing constraints after they start binding to determine whether they should be classified as M2M; and
- Delays in activating current M2M constraints once they are binding.

We developed a series of screens to identify constraints that should have been coordinated but were not because of these three issues. Table 10 shows the total congestion on these constraints. For the first two reasons (never classified and testing delay), we account for the time needed to test a constraint by removing the first day a constraint was binding.

MISO has a tool to identify potential M2M constraints that should be tested. Nonetheless, the value of congestion on SPP constraints that were never tested was significant, so we encourage MISO to evaluate ways to improve its M2M processes and timeliness of the testing process.

Table 10: Real-Time Congestion on Constraints Affected by Market-to-Market Issues
2022–2024

Item Description	PJM ($ Millions)			SPP ($ Millions)			Total ($ Millions)		
	2022*	2023	2024	2022*	2023	2024	2022*	2023	2024
Never classified as M2M	$6	$5	$31	$55	$33	$4	$61	$38	$35
M2M Testing Delay	$7	$5	$2	$44	$40	$21	$51	$45	$23
M2M Activation Delay	$1	$0	$2	$6	$1	$1	$7	$2	$3
Total	$14	$10	$35	$105	$74	$26	$119	$84	$61

*We have excluded the Winter Storm Elliott days (12/22-12/27/2022).

Market-to-Market Test Criteria Software

Identifying the constraints to coordinate under the M2M processes is important to ensure both efficient and reliable coordination, to establish equitable settlements, and to improve the price signals in the NMRTO market. Currently, a constraint will be identified as an M2M constraint when the NMRTO has:

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

These two tests are not optimal in identifying constraints that would benefit from coordination because they do not consider the economic relief the NMRTO will likely have available.[20] The single generator test is particularly questionable because it ignores the size and economics of the unit—this test does not ensure that the NMRTO has any economic relief.

Our analysis of this in Section V.G of the Analytic Appendix shows several M2M constraints for which the NMRTO has a small share of the economic relief and ability to help manage the congestion. Most of these constraints should not be M2M constraints because the coordination savings are likely less than the administrative costs.

Based on this analysis, we find that the current tests, particularly the five percent GSF test, often identify constraints for which the benefits of coordinating are very small—especially high-voltage constraints where GSFs tend to be higher. Hence, we recommend the five percent test be replaced by two potential discrete tests based on the available relief controlled by the NMRTO:

- The share of available relief capability from the NMRTO (e.g., 10 percent); and/or
- The NMRTO relief as a percentage of the transmission limit (e.g., 10 percent).

Our analysis shows that implementing this recommendation would likely reduce the total number of M2M constraints. This is important because the number of coordinated market-to-market constraints has been rising rapidly in recent years.

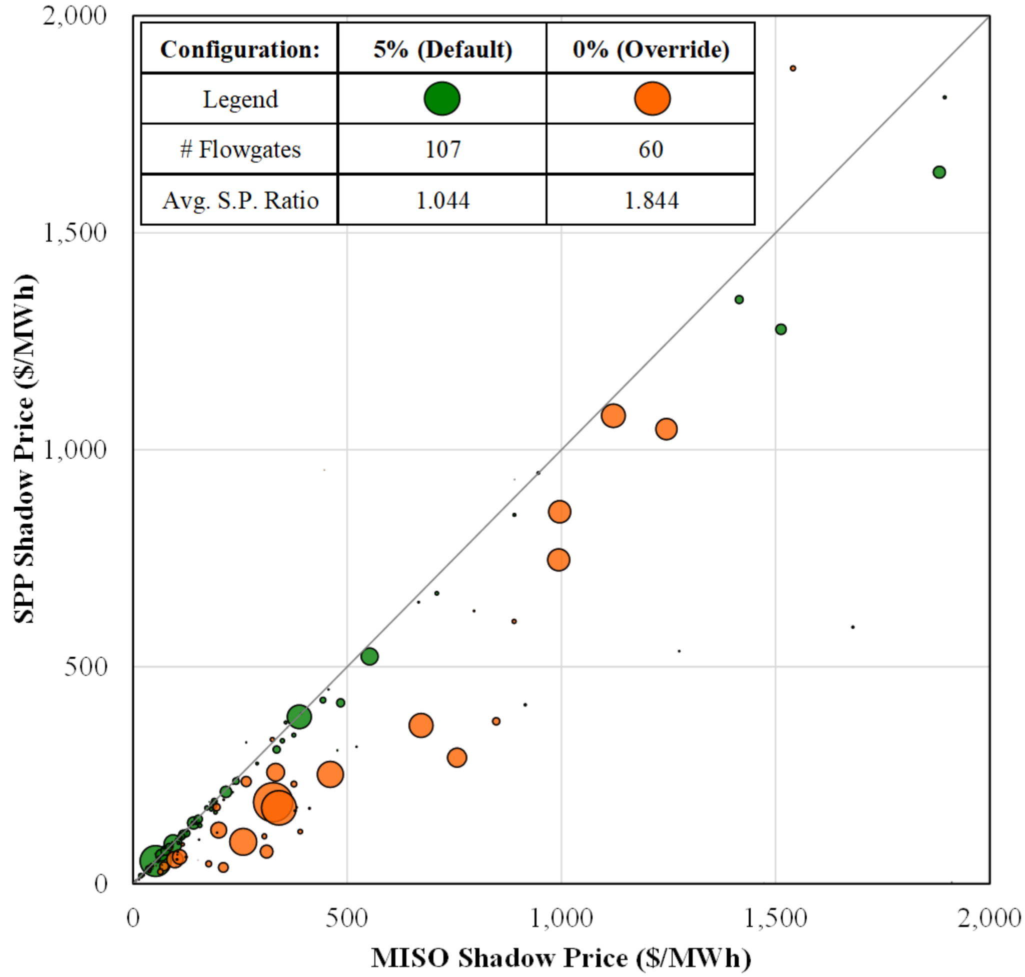
Congestion Convergence and Constraint Transfers

A core component of the M2M coordination is the software that determines the relief that will be requested from the NMRTO. The goal of the coordination is for the value of the congestion (as reflected in the constraint shadow price) in the MRTO on NMRTO dispatches to converge. If insufficient relief is requested, the MRTO's shadow price will remain much higher than the NMRTO and significant savings will be unachieved.

The M2M relief software contains parameters (adders) used to increase the relief request quantity by a given percentage. These adders are applied when the baseline relief request is too low. MISO sets the adders to five percent by default, but operators can override this value on a per-flowgate basis. SPP has often advocated for setting the adders to zero on its constraints. In Figure 31, we show the shadow price convergence on all flowgates controlled by MISO in 2024. Each bubble represents one flowgate, colored green for default adders and orange for adders overridden to zero, and sized based on congestion value. The diagonal reference line represents ideal convergence, with equal shadow prices in both markets.

[20] Economic relief is any relief that could be provided in five minutes at a shadow price less than $200.

Figure 31: Shadow Price Convergence on MISO-Controlled M2M Flowgates in 2024



The analysis shows that utilizing adders equal to zero often produces very poor convergence. For the flowgates configured with zero adders, MISO's shadow price is often nearly double that of SPP. The majority of the most-congested MISO-controlled flowgates in 2024 were adversely affected by this choice of adders. Finally, the lack of convergence caused by these issues significantly increases MISO's M2M costs.

MISO and SPP can agree to transfer monitoring responsibilities of a flowgate from the MRTO to the NMRTO, which are referred to as reverse-role flowgates. Ideally, this should occur only when the NMRTO controls a significant majority of economic flow relief on a flowgate. We found that most of the constraints that were coordinated with adders equal zero by MISO were SPP flowgates that had been transferred to MISO as reverse-role flowgates because SPP requested zero adders. We also found that that some of these reverse-role flowgates likely should not have been transferred because MISO did not have more economic relief on the flowgates than SPP. To address the costs and inefficiencies caused by these issues, we recommend MISO:

- Adopt criteria for agreeing to monitor SPP constraints as reverse-role flowgates; and

- Condition acceptance of monitoring responsibility for SPP constraints on the use of reasonable adders.

Our evaluation also finds that the convergence of M2M constraints is much worse in the day-ahead market. MISO and PJM implemented a process to coordinate and exchange FFEs in the day-ahead market, but do not actively use this process. We recommend MISO continue to work with SPP and PJM to implement FFE exchanges on M2M constraints.

E. Congestion on Other External Constraints

In addition to congestion from internal and external M2M constraints, congestion in MISO can occur when MISO models the impact of its own dispatch on external constraints. MISO is obligated to activate these constraints and reduce its market flows when other system operators invoke Transmission Loading Relief (TLR) procedures. This results in MISO's LMPs reflecting the marginal cost of providing the requested relief and associated congestion costs being collected from MISO's customers. MISO receives relief requests that are often inefficient and inequitable for these constraints because:

- MISO receives relief obligations based on forward direction flows across the impacted flowgates, even if on net (when reverse-direction flows are included) its market flows are relieving the constraint; and
- Virtually all of MISO's flows over external constraints are deemed to be non-firm (and thus subject to curtailment before firm transactions) even though most of MISO's flows are associated with dispatching network resources to serve MISO's load.

As a result, MISO's relief obligations are often large and generate substantial congestion costs. Further, we have generally found that the external TLR constraints are often not actually physically binding when they are severely binding in MISO in response to a relief request. To address this, we have recommended that MISO pursue a JOA with the neighboring systems that call TLRs most frequently—TVA and IESO—which would allow MISO to coordinate congestion relief with them. Because TVA acts as the reliability coordinator for AECI, such a JOA would produce substantial benefits by allowing AECI resources to be utilized to provide significant economic relief on MISO's transmission constraints and vice versa.

F. Transmission Ratings and Constraint Limits

For the past several years we have estimated significant potential benefits from improved utilization of the transmission system, especially broader application of Ambient Adjusted Ratings (AARs) and emergency ratings. For most transmission constraints, the ability to flow power through the facility is related to the heat caused by the power flow. When temperatures are cooler than the typical assumption used for rating the facilities, additional power flows can be accommodated.[21] Therefore, if TOs develop and submit ratings adjusted for temperature or other relevant ambient conditions, they would allow MISO to operate to higher transmission limits and achieve substantial production costs savings. Most TOs do not provide ambient-adjusted ratings. One of the reasons for this is that there is little economic incentive to do so.

In December 2021, FERC issued Order 881 that requires TOs to provide AARs and emergency ratings based on facility specific evaluations by mid-2025. On March 17, 2025, MISO filed a motion to extend the compliance deadline to the end of 2028 because of software delays. We protested this extension for the application of AARs in the real-time market because this element of Order 881 mandate could be fully satisfied over the next year and because the vast majority of the benefits of AARs will accrue from the real-time market.

Estimated Benefits of Using AARs and Emergency Ratings

As in past years, we have estimated the value of operating to higher transmission limits that would result from consistent use of temperature-adjusted and emergency ratings for MISO's transmission facilities.[22] This analysis is described in detail in Section V.E of the Analytic Appendix and summarized in Table 11.

Table 11: Benefits of Ambient-Adjusted and Emergency Ratings
2023–2024

		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2023	**Midwest**	$171.8	$89.93	$261.7	17	16.2%
	South	$1.2	$7.74	$8.9	5	6.7%
	Total	**$172.9**	**$97.7**	**$270.6**	**22**	**15.5%**
2024	**Midwest**	$122.5	$89.98	$212.5	24	12.9%
	South	$10.1	$8.98	$19.1	1	8.9%
	Total	**$132.6**	**$99.0**	**$231.6**	**25**	**12.4%**

Over the past two years, the results show average benefits of 14 percent of the real-time congestion value. The combined total potential savings in 2023 and 2024 were half of a billion dollars. The benefits of temperature adjustments tend to accrue primarily in the non-summer months when static ratings are most understated. The benefits of using emergency ratings are more evenly distributed throughout the year. The Analytical Appendix details how these estimated benefits in 2024 are distributed in the areas served by transmission owners.

21 Temperature is one factor, while ambient wind speed, humidity, and solar radiance can also be important determinants of dynamic ratings. Our analysis evaluates only ambient temperature impacts.

22 We used temperature and engineering data to estimate the temperature adjustments and assume emergency ratings are 10 percent higher than the normal ratings, which is based on other facilities for which TOs submit emergency ratings. We estimate the value of both increases based on the shadow prices of the constraints.

G. Operator Congestion Management Actions

MISO operators have the critical role of maintaining reliability, which can require operator actions that include actions needed to avoid transmission violations. We evaluate these actions in this subsection because they can have sizable impacts on market outcomes. Ultimately, managing network flows through the market dispatch software to the maximum extent possible should be the goal. This can be a challenge and prompt operator actions when:

- Resources do not respond to MISO's dispatch instructions, which has been an issue with a number of the intermittent renewable resources; and
- Forecast errors for the output of intermittent resources, discussed in Section III.B.

Operator interventions can be classified based on the effectiveness and the efficiency of the actions for the situation the operators are addressing. In principle, operator interventions that enable the market to address the issue will be more efficient than interventions that circumvent the models. Additionally, some operator actions are not effective for certain issues. Table 12 describes the main types of interventions that are available to operators and the associated pros and cons of these actions for addressing transmission-related reliability concerns.

Table 12: Types of MISO Operator Intervention

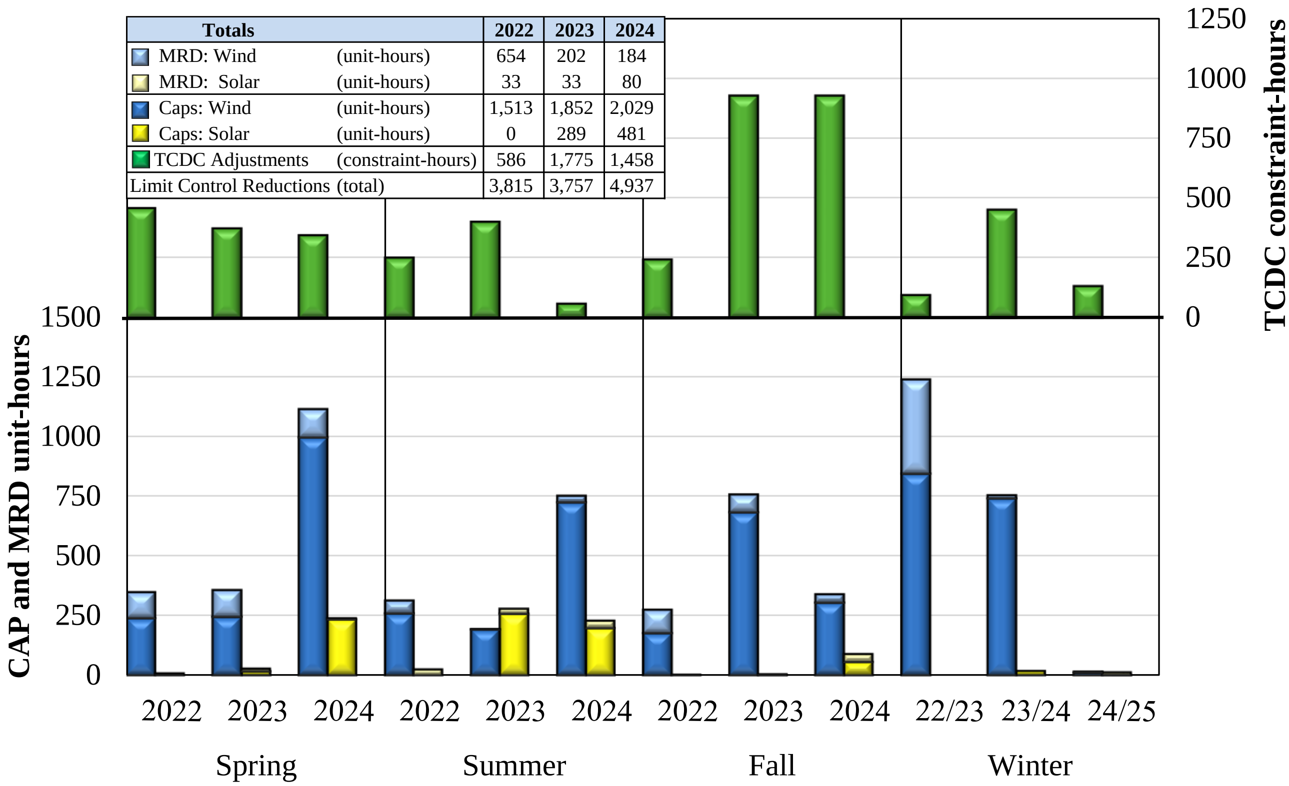
Operator Decisions	Effect of Action	Pros / Cons
TCDC Adjustment	Allows the dispatch model to access more costly dispatch actions to lower constraint flows.	Allows the dispatch model to optimally manage the constraint.
Commit Resources that can Provide Relief	Reduces flows on constraints by providing counterflows.	When units are economic to commit, they will lower costs and allow the dispatch to better manage the flows.
Transmission Derate with Limit Control Adjustment	Causes the dispatch to reduce the modeled flows to makes room on the constraint for the unmodeled constraint flows.	An efficient means to account for *unmodeled* flows. Not efficient or effective when the violation is caused by modeled flows.
Manual Redispatch (MRD)	Manually specifies a dispatch level for a resource to reduce constraint flows.	Provides quick relief, but is rarely efficient. Prevents the dispatch from efficiently pricing the congestion and increases uplift.
Cap Resources	Manually specifies a maximum dispatch level for a resource to prevent increasing constraint flows.	Effectively limits flows, but is rarely efficient. Prevents the dispatch from efficiently pricing the congestion and increases uplift.

The top three actions listed in the table are much more efficient than the bottom two because they would utilize the markets to address the issues or would be compatible with the markets:

- Increasing the TCDC raises the costs the dispatch model will incur to manage the constraint, which is effective when the constraint is already in violation and no additional relief can be accessed at the current TCDC.
- Committing resources to relieve congestion is efficient and compatible with the market when the LAC model recommends the commitments as economic.
- Derating a transmission constraint in the dispatch model will cause MISO's dispatch model to redispatch resources around the constraint and is effective when there are un-modeled physical flows that are not accurately perceived by the dispatch model.

The final two actions circumvent the market and are generally less efficient – manual re-dispatch (MRD) and dispatch caps that override or constrain the market's dispatch of the units. This raises costs and prevents prices from reflecting the costs of these actions. Figure 32 shows the frequency of all of these actions.

Figure 32: MISO Operator Actions for Congestion Management



Totals		2022	2023	2024
MRD: Wind	(unit-hours)	654	202	184
MRD: Solar	(unit-hours)	33	33	80
Caps: Wind	(unit-hours)	1,513	1,852	2,029
Caps: Solar	(unit-hours)	0	289	481
TCDC Adjustments	(constraint-hours)	586	1,775	1,458
Limit Control Reductions	(total)	3,815	3,757	4,937

Figure 32 shows that the manual dispatch actions and dispatch caps have been increasing as the penetration of intermittent renewables increases. This raises efficiency concerns, but we have been collaborating with MISO to improve these procedures. These improvements have already resulted in sizable reductions in dispatch capping and MRD activity in early 2025. We continue to encourage MISO to expand its use of TCDC adjustments in lieu of MRDs or caps.

Additionally, MISO is working on other changes we discuss in Section IV of this report that will improve the real-time market forecasts and the incentives to follow dispatch instructions for intermittent resources. These improvements are critical because most of the transmission congestion challenges that have compelled operators to take the actions described above have been caused by forecasting or dispatch issues related to intermittent resources.

Figure 32 also shows that the frequency of manual transmission deratings through “limit control” reductions increased in 2024. These deratings should be minimized because their cost can be substantial. We estimated their cost was $125 million in 2023 and $144 million in 2024. The most common and appropriate use of the limit control is to derate transmission limits to account for deviations between modeled and actual flows (unmodeled flow or deviations). However, in some cases the limit control adjustments are sub-optimal and lead to inefficient market outcomes. Over the past 6 months, we have worked with MISO to develop guidelines for the efficient use of the limit control parameter. MISO is working to implement these guidelines, which should improve efficiency and effectiveness of the manual transmission deratings.

H. Other Key Congestion Management Issues

MISO generally experiences significant real-time congestion each year, with a record $3.7 billion in 2022 and nearly $2 billion in both 2023 and 2024 despite extremely low natural gas prices. Hence, improvements aimed at the efficiency of congestion management can deliver sizable savings. We discussed many of these improvements above. We discuss four remaining improvements in this subsection.

Decommitting Resources that Cause Congestion

MISO does not decommit day-ahead committed units for economic reasons. While economic decommitments could result in DAMAP exposure, there are situations where decommitting a resource could alleviate severe congestion and reduce production costs. To assess the potential benefits of a day-ahead economic decommitment process, in our 2023 report we performed case studies using MISO’s Look-Ahead Commitment (LAC) model. These studies allowed LAC to suggest decommitments when they would lower costs. In our case studies, we found:

- Net savings were as high as $1 million in one instance of decommitting a unit, the largest savings of which were Excessive Congestion Fund (ECF) savings.
- Most cases also resulted in significant production cost savings.
- Congestion in these case studies fell by as much as $1.7 million and the decommitments eliminated all of the congestion to which they were contributing in two of the case studies.
- Increases in DAMAP costs that would have been paid to the decommitted resources were substantially less than the savings in every case.

Based on these results, we recommend MISO develop tools and procedures, identify day-ahead committed resources that are causing substantial congestion, and allow LAC to recommend the decommitment of these resources when economic.

Coordinating Outages that Cause Congestion

Generators take planned outages to perform periodic maintenance, to evaluate or diagnose operating issues, and to upgrade or repair various systems. Similarly, transmission operators take planned outages to implement upgrades and planned maintenance on transmission facilities, which generally reduce the transmission capability of the system during the outages. When outage requests are submitted, MISO evaluates the reliability effects of the planned outages, including conducting contingency and stability studies.

Participants tend to schedule planned outages in shoulder months, assuming the opportunity costs of taking outages are lower because temperatures tend to be mild and demand relatively low. However, this is not always true. Multiple participants may schedule generation outages in a constrained area or transmission outages into an area without knowing what others are doing. Absent a reliability concern, MISO does not have the authority to deny or postpone a planned outage, even when it could have sizable economic benefits. Figure 33 summarizes the effects of uncoordinated planned outages on congestion by showing the portion of the real-time congestion value for 2023 and 2024 that occurred on internal constraints that were substantially affected (at least 10 percent of the constraints' flows) by two or more planned outages.

Figure 33: Congestion Affected by Multiple Planned Generation Outages

2023–2024

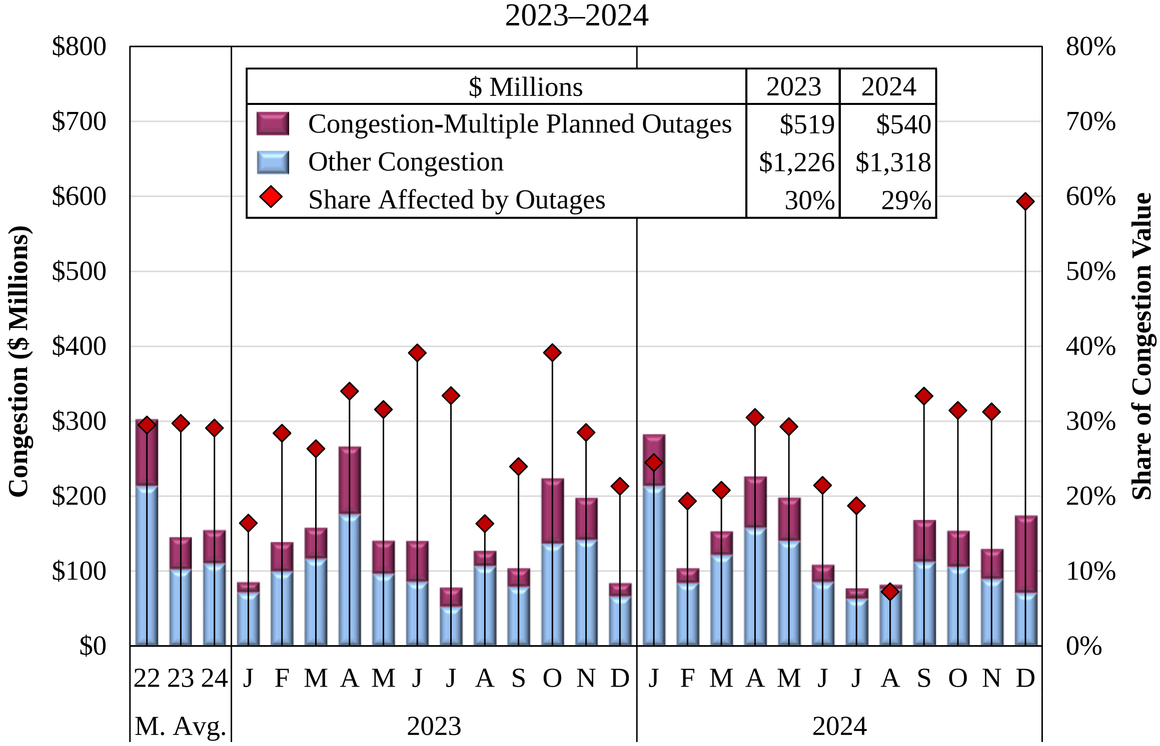


Figure 33 shows that 29 percent of the total real-time congestion on MISO's internal constraints in 2024 ($0.5 billion) was attributable to multiple planned generation outages. In six months of the year, more than one-third of the monthly congestion was associated with outages. Figure 33 may understate the effects of planned generation outages on MISO's congestion because we do not include the effects of transmission outages that are scheduled at the same time as planned generation outages. We continue to recommend that MISO seek broader authority to coordinate planned generation and transmission outages.

Identification and Use of Economic Transmission Reconfigurations

In the *2021 State of the Market Report*, we highlighted the benefits of identifying and deploying network reconfigurations (e.g., opening a breaker) when such options are reliable and economic. This is done on a regular basis by Reliability Coordinators to address congestion-related reliability concerns, normally under the procedures established in Operating Guides in consultation with the TOs. However, tremendous benefits can be achieved by utilizing reconfiguration options economically to manage congestion.

Therefore, we continue to recommend that MISO work with TOs to develop tools, processes, and procedures to identify and analyze reconfiguration options and then employ them to reduce congestion, rather than only for reliability. In 2022, MISO created the Reconfiguration for Congestion Cost Task Team to evaluate and implement reconfiguration requests. In 2024, very few reconfiguration requests were successfully implemented. However, MISO has no near-term plans to develop tools internally to suggest economic reconfiguration options, nor has it developed a process to ensure that evaluations of alternatives are timely. We recommend MISO pursue these enhancements.

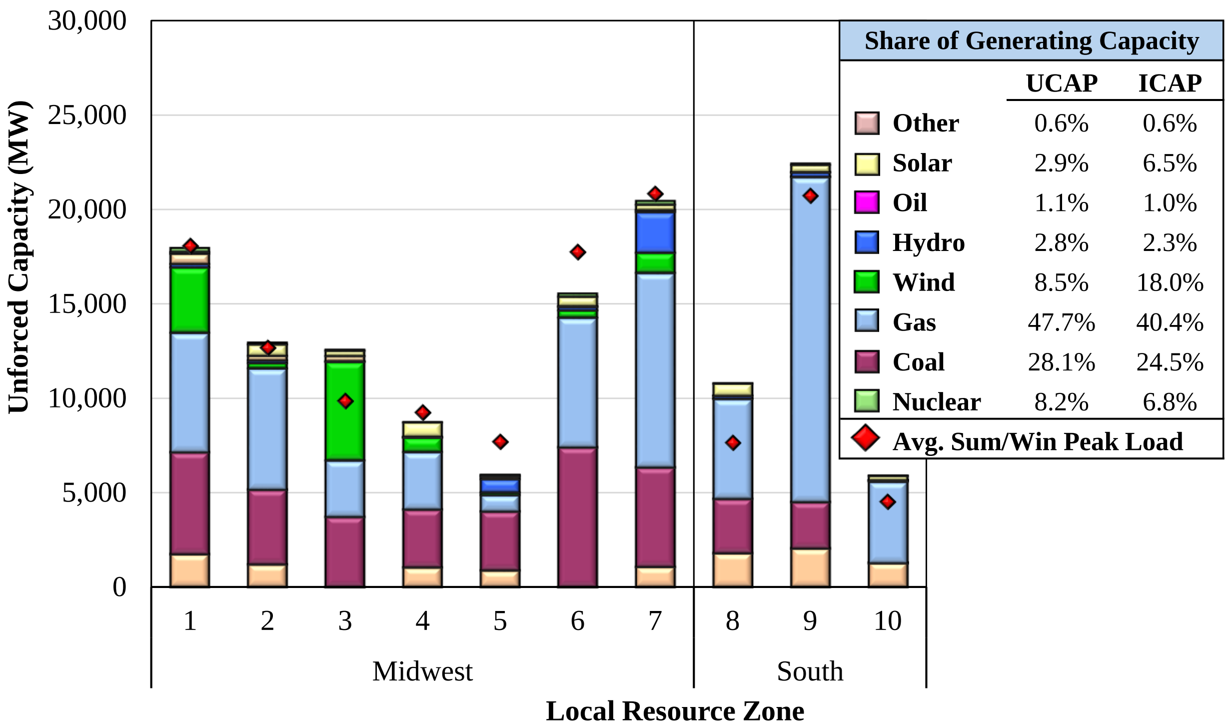
VI. Resource Adequacy

This section evaluates the performance of the markets in facilitating the investment and retirement decisions necessary to maintain adequate resources in MISO. We assess the adequacy of the supply in MISO for the upcoming summer and discuss recommended changes that would improve the performance of the markets.

A. Regional Generating Capacity

This first subsection shows the distribution of existing generating capacity in MISO. Figure 34 shows MISO's Unforced Capacity (UCAP) for by Local Resource Zone (LRZ) and fuel type, along with the coincident peak load in each zone.[23] UCAP values account for forced outages and intermittency. Therefore, UCAP values for wind and solar units are much lower than Installed Capacity (ICAP) values, as shown in the inset table.

Figure 34: Distribution of Existing Generating Capacity
By Fuel Type and Zone,



Share of Generating Capacity	UCAP	ICAP
Other	0.6%	0.6%
Solar	2.9%	6.5%
Oil	1.1%	1.0%
Hydro	2.8%	2.3%
Wind	8.5%	18.0%
Gas	47.7%	40.4%
Coal	28.1%	24.5%
Nuclear	8.2%	6.8%

This figure shows that gas-fired resources account for a larger share of MISO's capacity than any other capacity type, including coal-fired resources. The figure also shows that the gas-fired

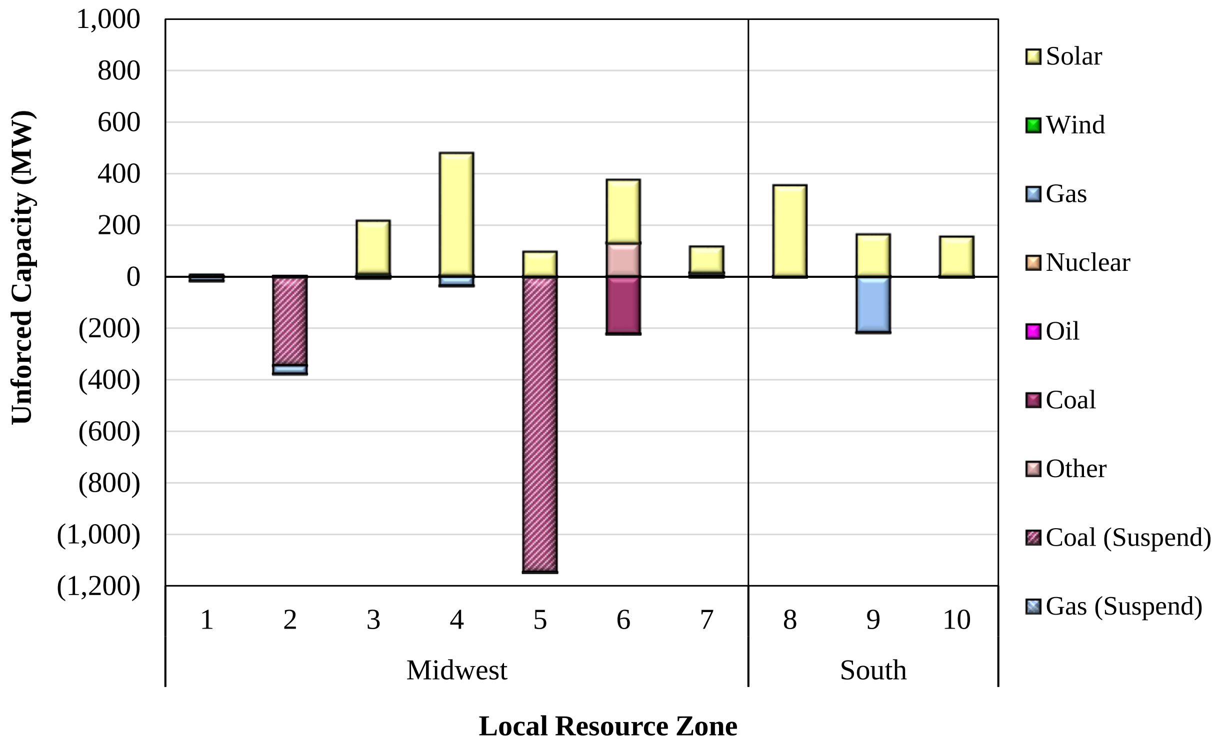
23 UCAP is based on data from the 2024–2025 PRA for the summer and winter seasons and excludes LMR capacity and capacity from resources that ceased operations before the end of the calendar year.

capacity shares are largest in MISO South, which tends to result in large interregional flows from MISO South to Midwest when natural gas prices are low and outages are minimal.

B. Changes in Capacity Levels

Capacity levels have been falling in recent years because of accelerating retirements of baseload resources that are being partially replaced with renewable resources. Figure 35 shows the capacity additions (positive values) and losses during 2024. The hatched bar indicates newly suspended resources, which rarely return to service.[24] Figure 35 does not show retirements for resources in 2024 that were suspended in 2023.

Figure 35: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone in



Capacity Losses

Two gigawatts of resources retired or were suspended in 2024, consisting of primarily coal and gas steam resources. Some of the suspended unforced capacity is under consideration for partial

24 Per Section 38 of the Tariff, the distinction between suspension and retirement is based on interconnection rights rather than the status or future plans for the facility. A suspended resource may be disassembled, maintaining its interconnection service to support a new facility at the same location. The status of the resource will eventually change from suspension to retirement if the interconnection rights are not used.

replacement and could return as new generation (primarily solar and battery) in the next three years.[25] These retirements are expected to continue in the near term because of state policies.

Attachment Y to the MISO Tariff requires suppliers seeking to retire or suspend a unit to notify MISO at least 26 weeks in advance unless the unit is in outage. Based on a reliability study of the transmission system, MISO may designate a resource as a System Support Resource (SSR) and provide compensation. An SSR cannot retire or be suspended until a reliability solution (e.g., transmission upgrades) can be implemented or the reliability condition no longer exists. SSRs have been granted infrequently, and currently only one resource in MISO is designated SSR.

New Additions

In 2024, 2 GW of unforced new capacity entered MISO. Approximately 1.8 GW of it was solar resources – roughly 1 GW in the Midwest and the remainder in the South. This more than doubled MISO's existing solar capacity to more than 5 GW (nameplate), which receive 50 percent capacity accreditation in summer months and 5 percent in winter. The other additions include 150 MW of new Energy Storage Resources (ESRs). We expect there will be a significant increase in ESRs in the coming years, many of which co-located with existing solar. In 2024, FERC approved MISO's DLOL accreditation methodology that will provide incentives for hybrid installations of battery and solar over standalone solar because the accreditation for solar resources will fall sharply in the coming years.

C. Planning Reserve Margins and Summer 2025 Readiness

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted summer peak loads in 2025. Since assumptions regarding the supply availability and load can substantially change the planning reserve margins, Table 13 shows a base case scenario and four additional scenarios that shows a realistic range of summer peak reserve margins.

Base Scenario. We have worked closely with MISO to align our base case scenario with those MISO used in its 2025 *Summer Readiness Workshop*, including the 1,900 MW transfer limit assumption between MISO South and Midwest.[26] This scenario also assumes that: a) MISO will be able to access all demand response resources in any emergency, and b) the summer planned outages will be limited to those scheduled and approved by April 1, 2025.

To report all values on an ICAP basis, we: (a) replaced the UCAP-based PRM added to demand response resources with an ICAP-based PRM, and (b) converted the UCAP-based ELCC value for wind resources to an ICAP-based value by scaling it up based on the ratio of the ICAP and UCAP PRM values. As conventional resources retire, we expect MISO's summer margins to fall below the planning requirement.

25 *See* https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

26 We disagree with this assumption, but we use it to align our Base Case with MISO's Base Case.

Realistic Scenario. Unfortunately, the assumptions in the base scenario are not very realistic, so we include a realistic scenario that assumes that:

- The transfer capability between MISO South and Midwest will be 2,300 MW, consistent with MISO operations;
- Planned and unreported outages and derates will be consistent with the average of the previous three years' summer peak months during on-peak hours; and
- MISO will only be able to access 75 percent of demand response resources in an emergency situation, consistent with historical observations.

Table 13: Summer 2025 Planning Reserve Margins

	Base Scenario	Alternative IMM Scenarios*			
		Realistic Scenario	Realistic <=2HR	High Temperature Cases	
				Realistic Scenario	Realistic <=2HR
Load					
Base Case	122,633	122,633	122,633	122,633	122,633
High Load Increase	-	-	-	7,338	7,338
Total Load (MW)	122,603	122,603	122,603	129,970	129,970
Generation					
Internal Generation Excluding Exports	134,812	134,812	134,812	134,812	134,812
BTM Generation	4,479	4,479	3,575	4,479	3,575
Unforced Outages and Derates**	(1,118)	(11,174)	(11,174)	(18,774)	(18,774)
Adjustment due to Transfer Limit	(5,635)	-	-	-	-
Total Generation (MW)	132,538	128,117	127,213	120,517	119,613
Imports and Demand Response* **					
Demand Response (ICAP)	9,655	7,241	3,052	7,241	3,052
Firm Capacity Imports	3,577	3,577	3,577	3,577	3,577
Margin (MW)	23,168	16,333	11,240	1,365	(3,728)
Margin (%)	**18.9%**	**13.3%**	**9.2%**	**1.1%**	**-2.9%**
Expected Capacity Uses and Additions					
Expected Forced Outages****	(6,965)	(5,769)	(5,769)	(5,769)	(5,769)
Non-Firm Net Imports in Emergencies	4,351	4,351	4,351	4,351	4,351
Expected Margin (MW)	20,554	14,914	9,822	(53)	(5,146)
Expected Margin (%)	**16.8%**	**12.2%**	**8.0%**	**0.0%**	**-4.0%**

* Assumes 75% response from DR.
** Base scenario shows approved planned outages for summer 2025. Realistic cases use historical averages during peak summer hours. High temp. cases are based upon MISO's 2025 Summer Readiness.
*** Cleared amounts for the Summer Season of the 2025/2026 planning year.
**** Base scenario assumes 5% forced outage rate for internal and BTM generation. Alternative cases use historical average forced outages/derates during peak summer hours.

The planning reserve margin shown in the base case is 18.9 percent – which exceeds the summer installed capacity Planning Reserve Margin Requirement (PRMR) of 15.7 percent. In the realistic scenario, the planning reserve margin falls to 13.3 percent, which is sufficient to cover expected forced outages. Additionally, MISO has the unique advantage of having substantial import capability from virtually every direction. Only a small amount of this import capability is reserved on a firm basis and used to import capacity. The remaining capacity is available on a non-firm basis and can be used to resolve shortages when they occur. Hence, the table includes additional imports that reflect the average amount of additional imports during emergency conditions.[27] This is conservative because the import levels would likely rise to much higher levels in response to shortage pricing in MISO.

Unfortunately, even the realistic scenario is optimistic because it assumes all resources not in a forced outage will be available during an emergency. However, since emergencies are the result of unforeseen events, MISO has historically declared emergencies between 10 minutes and four hours in advance. Because a large quantity of emergency resources offers longer notification times (often up to 6 hours), the second realistic scenario assumes only emergency resources that can start in two hours or less will be accessible, which reduces emergency demand response and behind-the-meter generation. This lowers the planning reserve margin to 9.2 and further to 8 percent after accounting for expected forced outages and non-firm summer imports.

High Temperature Scenarios. We include two other variants of the realistic scenarios to include the effects of hotter than normal summer peak conditions. The high-temperature scenarios are important because hot weather significantly affects *both* load and supply. High temperatures can reduce the maximum output limits of many of MISO's generators when outlet water temperatures or other environmental restrictions cause certain resources to be derated.[28] On the load side, we assume MISO's "90/10" forecast case (which should occur one year in ten).

The high-temperature cases using the realistic scenario and realistic plus limited emergency-only capacity both show that MISO's margin will be substantially negative (ranging from 0 to -4 percent) after accounting for imports and forced outages. MISO will likely be well into emergency conditions in these cases because it must maintain a positive margin of 2,400 MW to satisfy its operating reserve requirements. We note, however, that the roughly 8 GW of firm and non-firm imports shown in the table is far less than the total import capability. Therefore, MISO would not likely need to shed load in most of these cases provided that its markets are effective in motivating high levels of imports.

Overall, these results indicate that the system's resources are adequate for summer 2025 but may run short if the peak demand conditions are much hotter than normal. Going forward, planning reserve margins will likely continue to decrease as fossil-fuel and nuclear resources retire and are

27 The additional imports are consistent with the non-firm external support assumptions in MISO's 2025-2026 LOLE study.

28 These high-temperature derates are highly variable, so we assume high-temperature conditions from the MISO high-temperature scenario from its 2020 Summer Assessment.

replaced by renewable resources. Therefore, it remains important for the capacity market and shortage pricing to provide efficient economic signals to maintain adequate resources.

D. Capacity Market Results

The purpose of capacity markets is to facilitate long-term investment decisions to satisfy RTOs' planning requirements in conjunction with the energy and ancillary services markets. The economic signals provided by these markets together inform long-term decisions to build new resources and make capital investments in or retire existing resources. MISO's Resource Adequacy Construct allows load-serving entities (LSEs) to procure capacity to meet their Module E requirements either through bilateral contracts, self-supply, or the PRA. Resources clearing in MISO's PRA receive capacity revenues that, in addition to energy and ancillary services market revenues, should signal when new resources are needed.

PRA Results for the 2024–2025 Planning Year

MISO implemented two substantial reforms to its capacity market in 2022, adopting a seasonal market construct and an availability-based Seasonal Accredited Capacity (SAC) methodology for resources participating in the PRA that was implemented in 2023.[29] These changes addressed two recommendations that we have made in recent *State of the Market* reports.[30] The results for the 2024–25 PRA, the second auction under this new construct, are summarized in Table 14.

Table 14: 2024–25 Planning Resource Auction Results

Season	Capacity Procured	Offered Not Cleared	LOLE Target	Prices ($/MW-Day) Rest of Market	Prices ($/MW-Day) Zone 5 (MO)
Summer 24	136,064	4,624	0.10	$30.00	
Fall 24	125,551	9,327	0.01	$15.00	$719.81
Winter 24/25	131,377	17,061	0.01	$0.75	
Spring 25	127,791	8,825	0.01	$34.10	$719.81
PRA Year	130,196	9,959		$19.96	$367.59

Across the four seasons, market clearing prices averaged nearly $20 per MW-day, with a low of $0.75 per MW-day in the winter, a high of $34.10 per MW-day in the spring. Zone 5 was short of its local clearing requirement (LCR) in the fall and spring by 872.4 MW and 196.4 MW, respectively. The shortage was primarily attributable to the retirement of two large coal-fired resources at the end of the summer and long-duration planned outages in those shoulder seasons. MISO derived the ex-post shortage price of $719.81 per MW-day by dividing the Zone 5 annual CONE value of $131,725 by the 183 shortage days across those two seasons.

29 Docket No. ER22-495-000.

30 See Recommendations 2014-5 and 2018-5 from prior *State of the Market Reports*.

Unfortunately, these prices did not reflect true reliability risk in these zones. For example, Zone 5's average price for the planning year was two percent above annual CONE, but the probability of losing load was substantially below MISO's 1-in-10-year reliability standard. In 2024, MISO filed, and FERC accepted, MISO's new RBDC construct that we discuss below, which does not alter the vertical CONE-based pricing of LCRs. To address this concern, we have recommended MISO implement zonal MRI-based demand curves as soon as practicable and consider short-term changes to prevent price distortion in the interim.

Finally, winter prices dropped in the 2024–25 PRA to just $0.75 per MW-day, despite the high reliability risk that materialized in recent winter storms. This was largely due to the growth in accredited wind capacity, even though having high levels of wind output during winter storms is not guaranteed.

PRA Results for the 2025–2026 Planning Year

In June 2024, FERC accepted MISO's proposed tariff revisions to implement a downward-sloping RBDC in the MISO PRA beginning with the 2025–26 Planning Year.[31] MISO held its third seasonal capacity auction and first under the new RBDC construct in March 2025. The results for the 2025–2026 PRA are summarized in Table 15.

Table 15: 2025–26 Planning Resource Auction Results

Season	Capacity Procured	Offered Not Cleared	LOLE Target	Prices ($/MW-Day)		Excess Cleared	
				Rest of Market	MISO South	System	South
Summer 25	137,559	277	0.10	$666.50		1.017	1.008
Fall 25	132,516	4,260	0.01	$91.60	$74.09	1.023	1.002
Winter 25/26	131,000	3,262	0.01	$33.20		1.051	1.075
Spring 26	130,700	5,361	0.01	$69.88		1.012	0.997
PRA Year	132,944	3,290		$215.30	$210.92	1.026	1.021

Across the four seasons, market clearing prices average nearly $215 per MW-day, ranging from $33.20 per MW-day in the winter to a high of $666.50 per MW-day in the summer. These prices reflect the prevailing reliability value of capacity in MISO, clearing with a modest 1.7 percent surplus in the summer.

Capacity margins have fallen substantially in recent years, partly due to uneconomic retirements of merchant generators precipitated by the understated prices caused by the vertical demand curve that prevailed until this PRA auction. The summer clearing price would have been consistent with last year, falling to $20 per MW-day, had the auction run under a vertical demand

31 Docket No. ER23-2977-000.

construct, even though capacity margins fell substantially from the prior year because of the following factors:

- 4.6 GW decrease in SAC from the summer UCAP/ISAC ratio dropping from 1.04 to 0.99 (i.e., better alignment between LOLE UCAP and unit availability during RA hours);
- 1 GW increase in PRMR;
- 2.9 GW of thermal capacity suspensions/retirements; and
- 0.5 GW drop in offers from external resources.

While non-thermal accreditation increased by 5 GW with the addition of new solar, this was not enough to offset the capacity losses and additional demand.

Discussion of Other Issues Affecting the Performance of the PRA

Switchable External Resources. We have raised concerns about the use of controllable export adjustments to LCRs. This has been a particularly large issue in Zone 9 because of an external resource that can switch between MISO and ERCOT. This assumption lowers the LCR, essentially assuming the switchable resource will be available to MISO even though it has not been available in any emergency in recent years. This distorted the capacity prices in recent years, but MISO addressed this issue prior to the most recent 2025–2026 PRA.

Transfer Constraint. As part of the Settlement Agreement with SPP, MISO may dispatch up to 2,500 MW of energy transfers from MISO South to MISO Midwest. However, MISO limits the transfer capability in the South to North direction to 1,900 MW in the PRA. MISO mistakenly believes this reduction is necessary to account for firm interregional transmission reservations even though the reservations do not encumber MISO's utilization of the RDT. We recommend MISO increase the limit to reflect the expected transfer capability closer to 2,500 MW would more accurately reflect its ability to access capacity in MISO South.

E. Long-Term Economic Signals

Price signals in MISO's markets play an essential role in coordinating commitment and dispatch of units in the short term, while providing long-term economic signals that govern investment and retirement decisions for generators and transmission facilities. This subsection evaluates the long-term economic signals produced by MISO's markets by measuring the "net revenue" – the revenue a unit earns above its variable production costs if it runs when it is economic to run.

Well-designed markets produce net revenues sufficient to support new investment at times when existing resources are not adequate to meet the system's needs. Figure 36 and Figure 37 show estimated net revenues for a new combustion turbine (CT) and combined-cycle (CC) units for the last three years in the Midwest and South subregions. The figures also show the annual net revenue needed for these investments to be profitable (the Cost of New Entry or "CONE").

Figure 36: Net Revenue Analysis
Midwest Region, 2022–2024

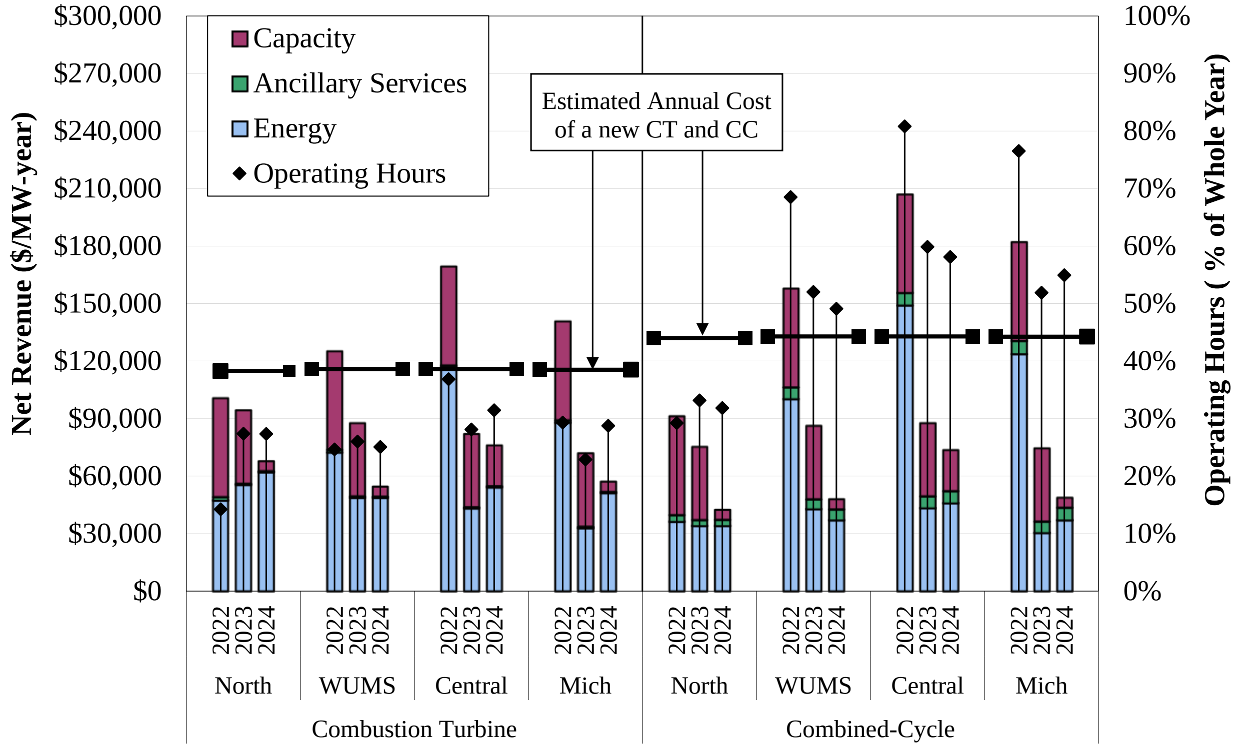
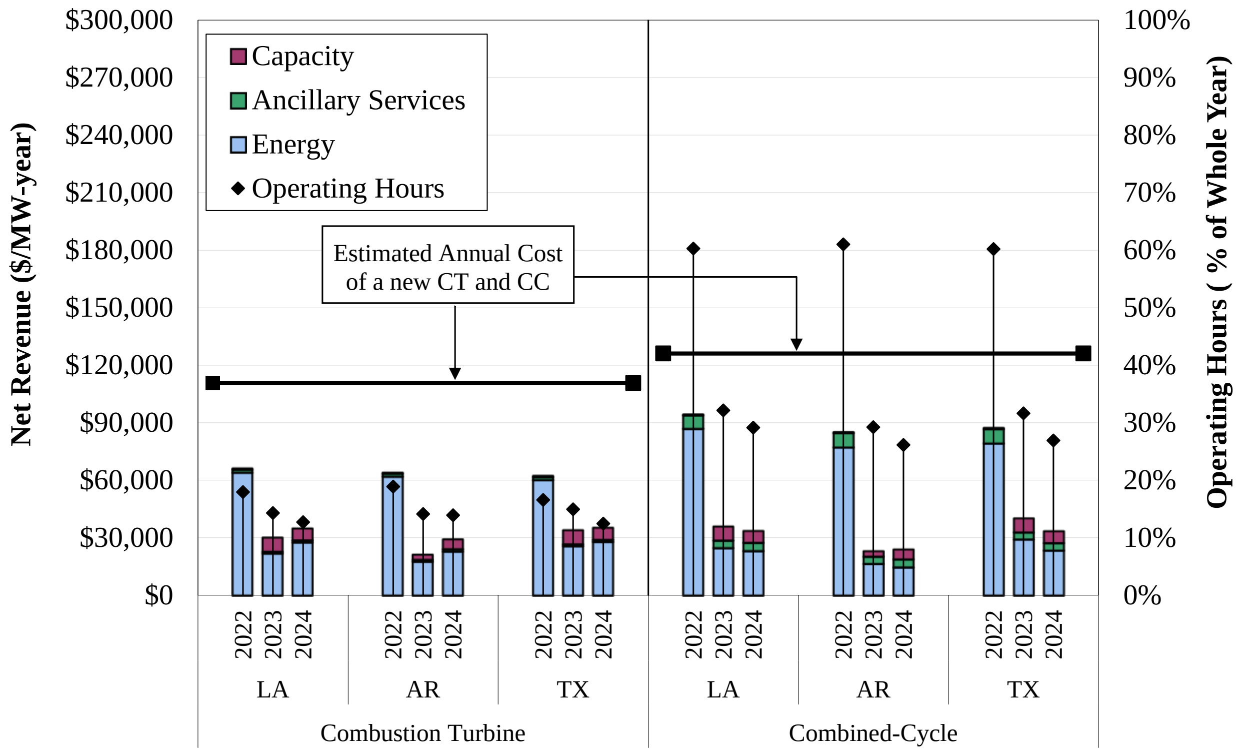


Figure 37: Net Revenue Analysis
South Region, 2022–2024



These figures show that net revenues decreased for both technologies in most zones in 2024, largely because lower natural gas prices contributed to lower energy and ancillary services prices throughout MISO and lower capacity prices in the Midwest. This lone exception was CTs in the South where their estimated net revenues were slightly higher.

Overall, MISO's economic signals had been undermined by capacity market design issues, including a poor representation of demand as a single quantity value (i.e., a vertical demand curve). However, MISO's implementation of the RBDC in the spring of 2025 for the 2025–2026 Planning Year will address this concern, raising capacity prices to much more efficient levels and allowing the market to maintain sufficient capacity.

F. Capacity Market Reforms

Although adoption of a reliability-based demand curve and improving capacity accreditation are the most important design improvements, we have also recommended that MISO consider the following additional improvements to provide better long-term incentives to MISO's suppliers and ensure that MISO's resource adequacy needs are satisfied.

Improvements to the Seasonal Market

During MISO's SAC filing in 2022, we raised some issues concerning elements that we believed reduced the benefits of the two broad changes implemented by MISO (seasonal market and accreditation based on availability during tight hours):[32]

- The seasonal design has four seasons that clear simultaneously at the beginning of the planning year. We recommended that MISO run prompt seasonal auctions so participants could optimize their offers in the next season given the results of the prior seasons; and
- The implemented design still generally overvalues inflexible resources, such as offline units with 24-hour lead times, accredited comparably to online or fast-starting resources.

We have also identified some additional issues with the design since the implementation of the new construct. Under MISO's current design, if a market participant does not replace ZRCs for a resource on planned outage for more than 31 days in a season, MISO assesses Capacity Replacement Non-Compliance Charge (CRNCC). The 31-day penalty threshold creates some inefficient incentives that may warrant a change in the CRNCC rules in the future.

Other Recommended Improvements to the PRA

Accreditation of Emergency Resources. Emergency-only resources, including LMRs and Available Max Emergency (AME) resources, are only required to deploy during emergencies when instructed by MISO. If they are not available to mitigate capacity shortages during

32 See *Motion to Intervene out of Time and Comments of the MISO IMM under ER22-495*.

emergencies, then they are not providing the reliability value MISO assumes and for which they are compensated. Some emergency-only resources have long notification times (up to 12 hours) or long start-up or shutdown times that render them essentially unavailable in most emergencies, which tend to occur with less than two hours' warning. Therefore, we had recommended that MISO develop a reasonable methodology for accrediting emergency-only resources in the PRA.

In 2025, MISO filed Tariff changes to reform LMR and emergency resource accreditation to better align with the Direct Loss of Load (DLOL) accreditation methodology that will be implemented in the 2028–2029 Planning Year. These changes along with earlier reforms should address our recommendation.

Modeling Transmission Constraints in the PRA. MISO currently only models import and export limits for each zone and the RDT transfer constraint from South to North. It runs a power-flow model after the initial PRA solution to determine whether any constraints are binding. Although transmission constraints have not been prevalent in the past, this is a poor approach that will fail to efficiently price any constraints that arise. Instead, MISO should model these constraints in the PRA by assigning a zonal shift factor for each modeled constraint that reflects how the resources in each zone affect the flow on the constraint. This would allow the zonal prices to accurately reflect these constraints.

VII. External Transactions

A. Overall Import and Export Patterns

Imports and exports play a key role in MISO because of its 12 interfaces with neighboring systems that have a total interface capability greater than 15 GW. Hence, the magnitude of the changes in imports and exports in response to prices can be large and significantly affect market outcomes. Interface price differences create incentives for physical schedulers to import and export between MISO and adjacent areas. Although average hourly imports fell from last year, MISO remained a net importer in 2024:

- Day-ahead and real-time hourly net scheduled interchange (NSI) averaged 2.4 and 2.6 GW, respectively (positive NSI values reflect net imports), down from 3.9 and 4.5 GW.
- MISO's largest and most actively scheduled interface is the PJM interface. MISO continued to be a net importer from PJM in 2024.
  - Hourly real-time imports from PJM averaged 1.9 GW, down 40 percent from 2023.
  - Some of the scheduling patterns between MISO and PJM were inefficient because of flaws in the RTOs' interface prices, as discussed below.

Scheduling that is responsive to interregional price differences captures substantial savings as lower-cost resources in one area displace higher-cost resources in the other area. Participants must schedule transactions at least 20 minutes in advance and, therefore, must forecast the price differences. The lack of RTO coordination of external transactions causes aggregate changes in transactions to be far from optimal. To evaluate the efficiency of external scheduling, we track the share of the transactions that were profitable (i.e., scheduled from the lower-priced market to the higher-priced market), which lowers the total production costs in both regions.

Markets are responsive to price signals in determining interchange levels. We studied this response and found that sustained prices over $100 per MWh have prompted changes in net imports averaging 600 MW, while prices over $400 per MWh prompted changes in net imports averaging 900 MW. Nonetheless, large savings are frequently untapped because it is often economic to schedule significantly more or less interchange. In 2024, over 65 percent of the transactions with PJM and over 60 percent of the transactions with SPP were scheduled in the profitable direction. Many hours still exhibit large price differences that offer substantial unrealized production cost savings.

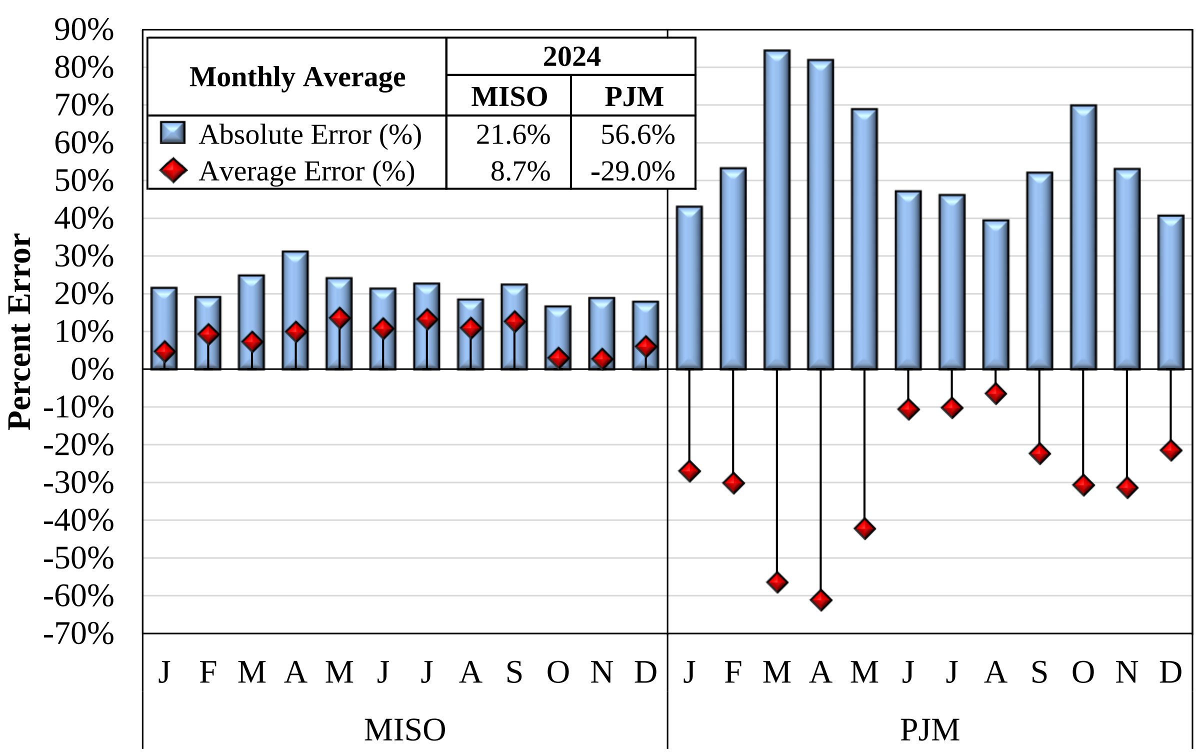
B. Coordinated Transaction Scheduling

On October 3, 2017, MISO and PJM implemented Coordinated Transaction Scheduling (CTS). CTS allows market participants to submit offers to schedule imports or exports between the RTOs within the hour. Offers clear if the forecasted spread between the RTOs' real-time interface prices 30 minutes prior to the interval is greater than the offer price. CTS transactions are settled based on real-time interface prices. In this subsection, we discuss the performance of the current CTS system and a fundamental reform to the CTS design that would allow it to perform much better.

Summary of CTS Performance

Up until early 2019, there had been almost no participation in CTS. In 2024, the hourly average quantity of CTS transactions offered and cleared remained extremely low at 40 MW and 15 MW, respectively. Over 99 percent of the transactions over the past two years have been in the import direction. CTS transactions remain a *de minimis* fraction of transactions at the PJM interface. We have previously shown that high transmission and energy charges have likely deterred traders from using CTS in lieu of traditional transaction scheduling. We have also concluded that persistent forecasting errors by MISO and PJM have likely hindered the use of CTS. We evaluated the forecasting errors for each RTO, measuring the percentage difference between the actual LMP and the forecasted price used for CTS. In Figure 38, we show the forecasting errors by month in both average and absolute average terms for MISO and PJM.

Figure 38: MISO and PJM CTS Forecast Errors
2024



This analysis shows significant inaccuracies in the forecast prices used for CTS, particularly in PJM where the forecasts are both large and biased. In 2024, the average difference between PJM's real-time LMPs and its forecast prices for the interface was negative 28 percent, and the average of the absolute difference was 57 percent.[33] For the same period, the average difference between MISO's real-time LMPs and its forecast prices for the interface was 9 percent, and the average of the absolute difference was 22 percent. When combined, these errors severely hinder the effectiveness of CTS in improving pricing at the interface because they create substantial risk for participants scheduling transactions through the CTS process. The poor forecasts suggest that CTS would likely clear many transactions that are uneconomic based on real-time spreads if participants submitted relatively low-cost CTS offers. These forecasts would also cause CTS to not clear many transactions that would otherwise be economic.

A comparable mechanism to CTS is in place between the New York ISO and ISO New England and is widely used, in part because the forecast prices are more accurate, and no charges are applied to these transactions. Hence, we continue to recommend that MISO eliminate all transmission and other charges applied to CTS transactions, while encouraging PJM to do the same. Additionally, we have concluded that it is unlikely for the RTOs to substantially improve their forecasts given the timing of the information used. Hence, we recommend the RTOs mitigate the adverse effects of the forecasts by modifying the CTS to clear transactions every five minutes through UDS based on the most recent five-minute prices in the neighboring RTO area. The following is an evaluation of this recommendation.

CTS with Five-Minute Clearing

We ran a simulation for 2024 of a CTS process that clears based on recent five-minute prices to evaluate the benefits of our recommendation. Instead of the markets clearing CTS offers on a 15-minute basis using forecasted prices from 30 minutes prior, the markets in our simulation clear CTS transactions every five minutes using interface price spreads from the previous interval. For each interval, we estimate an optimal clearing amount based on:

- The previous five-minute spread less cleared transaction fees;
- Assumed relationships of the prices in PJM and MISO to changes in the transactions scheduled between them, which was based on a regression analysis we performed; and
- An assumed aggregate offer curve beginning at the level of the incremental charges and rising at a rate of $1 per MWh every 167 MW ($6 per 1000 MW).

We identify the optimal clearing amount, accounting for any changes in the actual NSI, by applying the following constraints: (1) maximum change between five-minute intervals of 500 MW (in either direction), and (2) maximum total CTS import and export limits of 5,000 MW. Based on the adjustments calculated for each five-minute interval, we are able to estimate the price changes, production cost savings, and profits of the CTS participants.

33 PJM's forecast prices are from its intermediate term security-constrained economic dispatch tool (IT SCED).

We also used this model to evaluate the benefits of a five-minute CTS with SPP, with tighter constraints since MISO has a smaller interface with SPP than PJM: (1) maximum 5-minute change of 250 MW (in either direction), and (2) maximum total CTS import and export limits of 2,000 MW. Table 16 summarizes the results for both markets.

This analysis shows that redesigning the CTS process to adjust NSI on a five-minute basis offers substantial savings that are not being captured under the current process. The recommended five-minute CTS with PJM would have achieved more than $24 million in production cost savings versus only $740 thousand under the current process. Although adjustments would have occurred in 85 percent of intervals, these savings do not require large adjustments—which average roughly 100 MW. A five-minute CTS with SPP would have achieved more than $35 million in production cost savings with a similar level of adjustments.

Table 16: CTS with Five-Minute Clearing Versus Current CTS
2024

2024	Percent of Intervals Adjusted	Production Cost Savings	Profits	Percent Unprofitable
PJM				
Current CTS	1.0%	$739,801	$24,025	4.6%
5-Minute CTS	85.4%	$24,569,822	$12,340,542	19.5%
SPP				
5-Minute CTS	89.3%	$35,536,130	$21,431,956	18.8%

The improvement in the incentives for participants to utilize the CTS process is also notable. The CTS profits participants would have earned total more than $12 million from the cleared CTS transactions with PJM compared to profits in 2024 of just $24 thousand under the current process. The poor price forecasts and high charges applied to any CTS offers leave little to no opportunity to profit by participating in the CTS. Five-minute CTS in SPP would have also been very profitable for participants, producing profits of over $21 million. Hence, using the most recent five-minute prices is a substantial improvement and leads to more efficient CTS adjustments.

We have recommended since 2019 that MISO pursue this timelier form of CTS with both PJM and SPP but little progress has been made. MISO's Market System Enhancement will require MISO to re-develop the software to maintain the current CTS. Given its poor performance, MISO is considering eliminating it and pursuing a replacement process that is based on the 5-minute dispatch software. Since MISO, PJM and SPP solve their real-time dispatch models for multiple load level scenarios, these scenarios can be used to execute CTS transactions. For example, selecting the +200 MW case for MISO and the -200 MW case for PJM would effectuate a 200 MW CTS export. Making more timely adjustments in each real-time interval would achieve large savings, exceeding those in Table 16. These adjustments would also likely reduce ramp and reserve shortage-related price volatility, which has been increasing with greater renewable penetration.

C. Interface Pricing and External Transactions

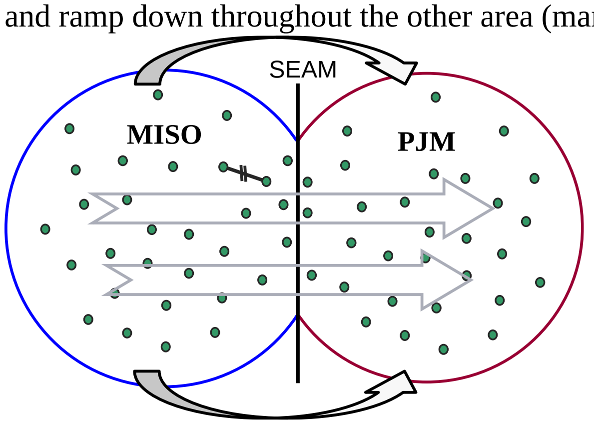
Each RTO posts its own interface price used to settle with physical schedules to sell to and buy power from the neighboring RTO. Participants will schedule flows between the RTOs to arbitrage differences between the two interface prices. Interface pricing is essential because:

- It is the sole means to facilitate efficient power flows between RTOs;
- Poor interface pricing can lead to significant uplift costs and other inefficiencies; and
- It is an essential basis for CTS to maximize the utilization of the interface.

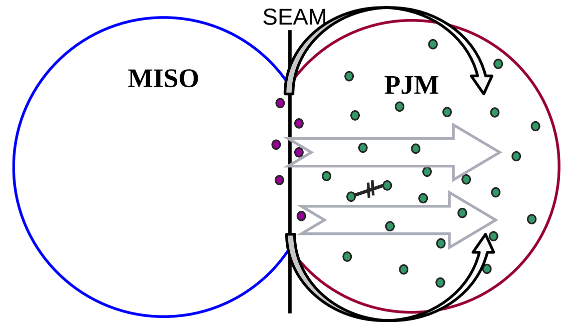
Establishing efficient interface prices would be simple in the absence of transmission congestion and losses—each RTO would simply post the interface price as the cost of the marginal resource on its system (the system marginal price, or "SMP"). Participants would respond by scheduling power from the lower-cost system to the higher-cost system until the SMPs equalize. However, congestion is pervasive on these systems, so the fundamental issue with interface pricing is estimating the congestion costs and benefits from 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 and, therefore, congestion effects can be accurately calculated. In contrast, *the source of an import (or sink for an export) is not known*, so it must be assumed in order to calculate the congestion effects. This is known as the *"interface definition"*. If the interface definition reflects the actual source or sink of the power, the interface price will provide an efficient transaction scheduling incentive and lower the costs for both systems.

In reality, when power moves from one area to the other, generators ramp up throughout one area and ramp down throughout the other area (marginal units), as shown in the figure to the left. This figure is consistent with MISO's interface pricing before June 2017, which calculated flows for exports to PJM based on the power sinking throughout PJM. This is accurate because PJM will ramp down all its marginal generators when it imports power. Because both RTOs price congestion on M2M constraints, some congestion had been redundantly priced by MISO and PJM and by MISO and SPP.



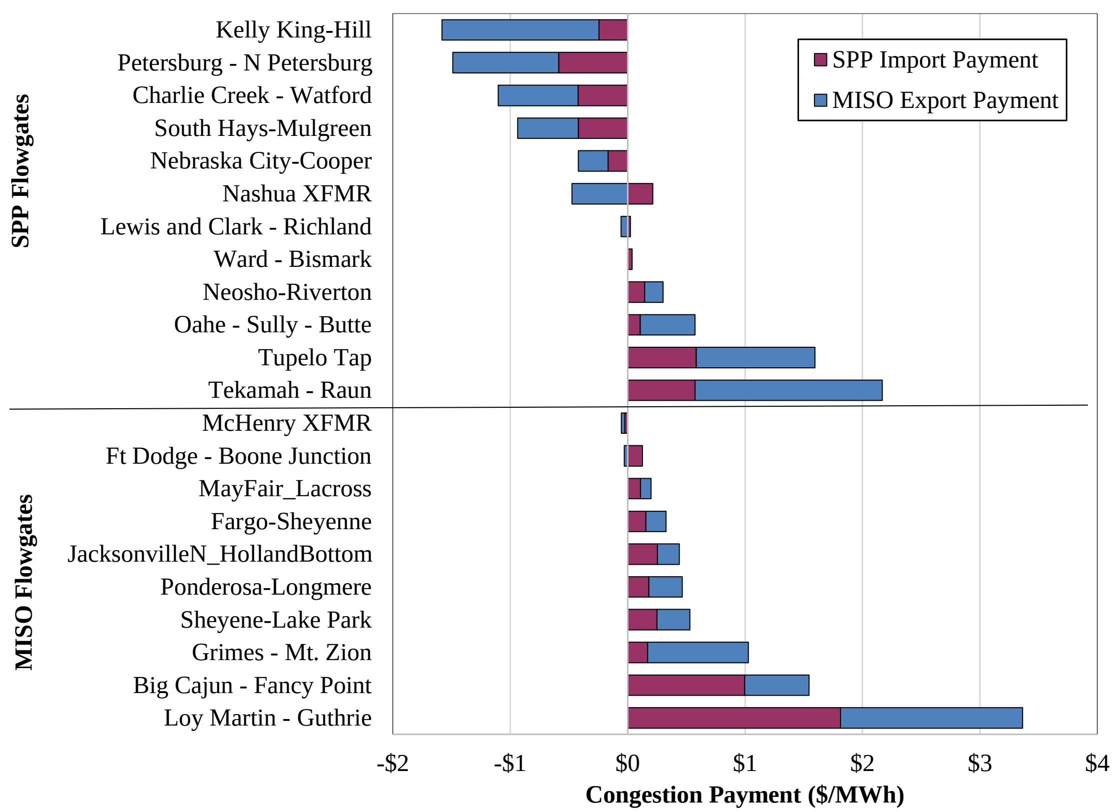
To address this concern, PJM and MISO agreed to implement a "common interface" that assumes the power sources and sinks from the border with MISO, as shown in the second figure to the right. This common interface" consists of 10 generator locations near the PJM seam with five points in MISO's market 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 will loop outside of the RTOs.



We have identified the location of MISO's marginal generators and confirmed that they are distributed *throughout* MISO, so the common interface definition likely sets inefficient interface prices. Our studies show that in aggregate, the common interface has led to larger errors and volatility at the interface. These results indicate that this approach was a mistake. Fortunately, MISO only uses this type of interface definition at the PJM interface, whereas PJM uses this approach on all its interfaces.

We have recently studied interface pricing at the MISO-SPP interface and verified that redundant congestion pricing is still occurring based on their overlapping interface definitions. When a M2M constraint binds, both RTOs price and settle with external transactions based on their respective estimates of the congestion effects of the transaction. Both RTOs' congestion estimates are typically similar, resulting in a rough doubling of the congestion settlement. To show how this occurs, we have calculated the average interface pricing component associated with selected M2M constraints. Figure 39 shows the congestion component calculated by both SPP and MISO for each constraint, separately showing MISO constraints and SPP constraints.

Figure 39: Constraint-Specific Interface Congestion Prices



The congestion payments in Figure 39 are displayed as the settlement of an export transaction from MISO to SPP. A negative value indicates that the participant would be charged; whereas a positive value indicates that the participant would be paid for congestion relief. Even though their interface definitions differ somewhat, this figure shows that both RTOs estimate very similar effects on each of the jointly managed constraints. Unfortunately, this results in congestion payments and charges that are roughly double the efficient level—the payment made by the MRTO. Although these payments may appear small, it is because they are averages of many intervals. In some intervals, the distortions exceed $30 per MWh.

This is important because it results in poor incentives for scheduling imports and exports when M2M constraints are binding. It also results in additional costs for the RTOs. When SPP makes a payment for a transaction because it would relieve a MISO constraint, this payment is not recouped through the M2M process. In other words, if both RTOs pay $20 per MWh for congestion relief to the same participant, MISO would receive some relief for having made the payment, while SPP as the NMRTO would receive no credit and would generally recover this cost through an uplift charge to load. Of course, these effects would be reversed if MISO pays a participant to schedule a transaction that relieves an SPP M2M constraint. Hence, this is an issue that hurts both RTOs while leading to inefficient transaction schedules and higher costs.

Given our findings regarding the common interface approach adopted with PJM, this approach should not be considered at the SPP interface. We encourage MISO and SPP to adopt an alternative approach to settle interchange congestion accurately. Hence, we recommend that the RTOs employ their current interface definitions, but that M2M constraints modeled by both RTOs only be included in the MRTO's interface price.

Interface Pricing for Other External Constraints

In addition to PJM and SPP M2M constraints, MISO also activates constraints located in external areas when neighboring system operators call TLRs, creating an obligation for MISO to re-dispatch its generation. It is appropriate for external constraints to be reflected in MISO's market models and internal LMPs, which enables MISO to respond to TLR relief requests efficiently. However, MISO is not obligated to pay importers and exporters that may relieve constraints in external areas. In fact, the effects of real-time physical schedules are excluded from MISO's market flow, so MISO gets no credit for any relief that its external transactions may provide and no reimbursements for the millions of dollars in costs it incurs each year. Hence, it is inequitable for MISO's customers to bear these costs.

In addition to the inequity, these congestion payments motivate participants to schedule transactions inefficiently for two reasons:

- In most cases, beneficial transactions are already being fully compensated by the area in which the constraint is located. MISO's additional payment is excessive and inefficient.

- MISO's pricing of the external TLR constraints is generally vastly overstated and provides inefficient scheduling incentives.

Fortunately, this issue is not difficult to address. We have recommended since 2012 that MISO simply remove the congestion related to external constraints from each of its interface prices. This change would resolve the interface pricing issue associated with external constraints on all of MISO's other interfaces (excluding the PJM and SPP interfaces).

VIII. Competitive Assessment and Market Power Mitigation

This section contains our competitive assessment of the MISO markets, including a review of market power indicators, an evaluation of participant conduct, and a summary of the use of market power mitigation measures in 2024. Market power in electricity markets exists when a participant has the ability and incentive to raise prices. Market power in electricity markets can be indicated by a variety of empirical measures, which we discuss in this section.

A. Structural Market Power Indicators

Economists and antitrust agencies often utilize market concentration metrics to evaluate the competitiveness of a market. The most common metric is the Herfindahl-Hirschman Index (HHI), which is calculated as the sum of the squared market shares of each supplier. An HHI of less than 1000 is generally considered low, while an HHI higher than 1800 is considered high. Market concentration is low for the overall MISO area (539) but very high in some local areas, such as WUMS (4193) and the South Region (3269), where a single supplier operates nearly 60 percent of the generation. However, the HHI metric does not include the impacts of load obligations, which affect suppliers' incentives to raise prices. HHI also does not account for the difference between total supply and demand, which is important because excess supply results in more competitive markets. Hence, the HHI is limited as an indicator of overall competitiveness.

A more reliable indicator of potential market power is whether a supplier is "pivotal", which is when its resources are necessary to satisfy load or manage a constraint. Our regional pivotal supplier analysis indicates that the pivotal supplier frequency rises sharply with load. This is typical in electricity markets because electricity cannot be economically stored. Hence, when load increases, excess capacity falls, and the large suppliers' resources may be needed.

We also evaluate local market power by identifying pivotal suppliers for relieving transmission constraints into constrained areas, including the five Narrow Constrained Areas (NCAs) and all Broad Constrained Areas (BCAs). NCAs are chronically constrained areas that raise more severe potential local market power concerns where tighter market power mitigation measures are employed. A BCA is defined when non-NCA transmission constraints bind. The BCA includes all generating units with significant impact on power flows over the constraint. Our results showed that a supplier was frequently pivotal in both types of constrained areas:

- On average, 56 percent of the active BCA constraints had at least one pivotal supplier.
- Over 80 percent of the binding constraints into both the MISO South NCAs and the Midwest NCAs had at least one pivotal supplier.

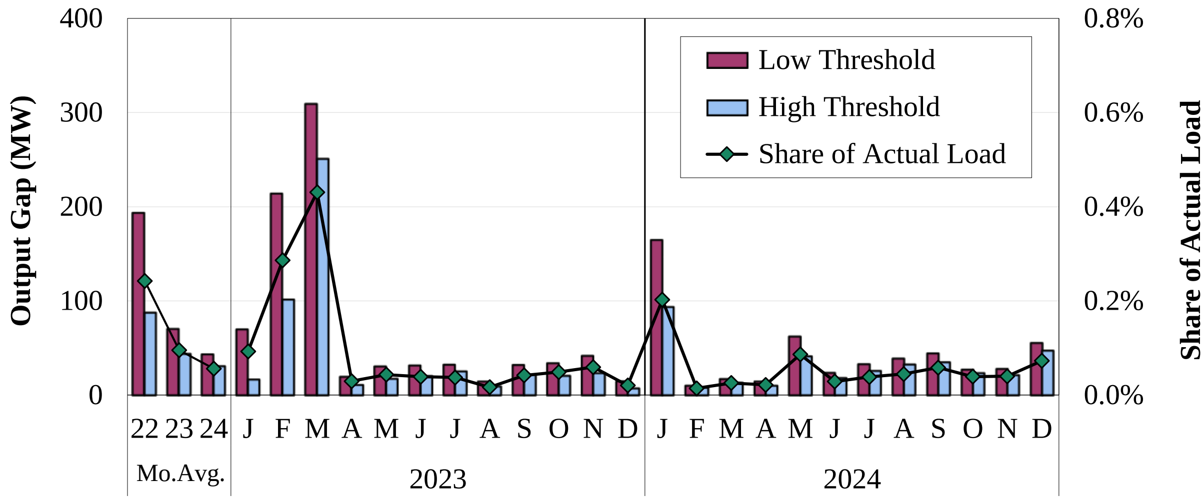
Overall, these results indicate that local market power persists, with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

B. Evaluation of Competitive Conduct

Despite these indicators of structural market power, our analyses of participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power. This is confirmed in aggregate measures of overall market competitiveness, including a "price-cost mark-up". This measure compares the system marginal price based on actual offers to a simulated system marginal price assuming all suppliers submitted offers at their estimated marginal cost. We found an average system marginal price-cost mark-up of -2.5 percent in 2024. The fact that the mark-up was very small (and negative) indicates that the markets were highly competitive overall.

Figure 40 shows the "output gap" metric, which we use to detect instances of potential economic withholding. The output gap is the quantity of power not produced from resources whose operating costs are lower than the LMP by more than a threshold amount. We perform the output gap analysis using the Tariff's conduct threshold (the "high threshold") and a "low threshold" equal to one-half of the conduct threshold. The output gap includes both units that are online and submitting inflated energy offers, as well as units that were not committed because of inflated economic or physical offer parameters.

Figure 40: Economic Withholding – Output Gap Analysis
2023–2024



Low Threshold Results by Unit Status (MW)

Offline	95	55	31	29	170	301	11	23	22	23	6	25	17	27	4	98	3	8	6	56	18	25	31	37	22	24	49
Online	99	15	12	41	43	8	9	8	10	9	8	7	17	15	11	66	7	10	9	6	6	8	7	8	6	4	7

High Threshold Results by Unit Status (MW)

Offline	59	39	26	12	94	247	6	12	15	21	6	19	16	21	4	84	3	6	4	38	14	22	29	31	20	19	44
Online	28	5	5	5	7	4	5	6	5	5	4	3	5	3	3	9	6	7	6	4	5	4	4	4	4	3	3

The figure shows that the average monthly output gap level was 0.06 percent of load in 2024, which is effectively *de minimis* and lower than in 2023. Beginning in the fall of 2021, multiple coal-fired resources employed fuel conservation measures to ensure that they would have sufficient fuel inventory going into the winter months. Several of these resources had not requested reference level consultations to reflect their conservation plans, which is evidenced in the higher output gap indicated during 2022. By winter 2022, most coal-fired resources experiencing fuel and reagent supply issues reflected the conservation measures in their reference levels and by the spring of 2023 coal supply issues resolved. Although these results raise no competitive concerns, we monitor these levels on an hourly basis and routinely investigate potential withholding.

C. Summary of Market Power Mitigation

Market power mitigation in 2024 effectively limited the exercise of market power. Mitigation in the energy market remained infrequent. Market power mitigation in MISO's energy market occurs pursuant to automated conduct and impact tests that utilize clearly specified criteria. The mitigation measure for economic withholding caps a unit's offer price when the offer exceeds the conduct threshold and raises energy market clearing prices or RSG payments substantially. Because conduct has generally been competitive, market power mitigation has been imposed infrequently. The mitigation thresholds differ depending on the three types of constrained areas that may be subject to mitigation:

- Broad Constrained Areas (BCAs);
- Narrow Constrained Areas (NCAs); and
- Dynamic NCAs, which are transitory constrained areas that can occur when outages create severe congestion.

The market power concerns associated with NCAs and Dynamic NCAs are greatest because they address chronic or severe congestion. As a result, conduct and impact thresholds for NCAs and Dynamic NCAs are much lower than they are for BCAs. The thresholds for NCAs depend on how frequently the NCA constraints bind, while a fixed threshold of $25 per MWh is used for Dynamic NCAs. No Dynamic NCAs were declared in 2024. The lower NCA thresholds generally lead to more frequent mitigation in NCAs, even though there are many more BCAs.

Market power mitigation in MISO's energy market remained infrequent because conduct was generally competitive. The incidence of mitigation increased in 2024, but less than one percent of real-time market hours across 18 days were affected, down from 28 in 2023. Assuming the real-time market is effectively mitigated, the day-ahead market should not be vulnerable to market power abuse as long as it is liquid, with fulsome participation by physical and virtual trading participants. Hence, mitigation was applied on just seven day-ahead market days in 2024, up from six in 2023.

However, market power can be exercised by suppliers whose generation is needed to address reliability issues, with the rents extracted through RSG payments. RSG payments occur when a resource is committed out-of-market to meet the system's capacity needs, local reliability requirements, or to manage congestion. If the resource offers include inflated economic or physical parameters, it may result in inflated RSG payments, and the resource may be mitigated. Commitments to satisfy system-wide capacity needs are not subject to mitigation because competition is generally robust to satisfy those needs.

Average mitigation of day-ahead and real-time RSG payments were 32 and 61 percent lower, respectively, in 2024 than in 2023. While lower natural gas prices were a primary driver, MISO made fewer real-time commitments overall in 2024 compared to prior year. This operational change contributed to the significant decrease both in the RSG that was incurred and in the frequency with which these commitments led to mitigation.

IX. DEMAND RESPONSE AND ENERGY EFFICIENCY

Demand Response (DR) involves actions taken by electricity consumers to reduce their consumption when their value of consuming electricity is less than the prevailing marginal cost to supply it. Facilitating DR is valuable because it contributes to improved operational reliability in the short term and lower-cost resource adequacy in the long term.

Even modest reductions in consumption by end-users during high-priced periods can greatly reduce the costs of committing and dispatching generation. These benefits underscore the value of facilitating efficient DR through wholesale market mechanisms and transparent economic signals. However, it must be done carefully to avoid creating inefficient incentives for DR resources and gaming opportunities. In this section, we discuss the current level of participation of DR and energy efficiency resources (EE) and identify significant concerns that have arisen related to MISO's approach to incorporating these demand resources in the market.

A. Demand Response Participation in MISO

Table 17 shows DR participation in MISO and compares it to NYISO and ISO-NE in the last three years. The table shows DR resources in MISO can be divided into one or more of the following three categories:[34]

- Load-Modifying Resources (LMRs) that are capacity resources obligated to curtail in emergencies and satisfy Planning Reserve Margin Requirements (PRMR);
- Demand Response Resources (DRRs) that economically respond to prices in the energy and ancillary services markets; and
- Emergency Demand Response Resources (EDRs) that are called in emergencies, but that are not obligated to offer and do not satisfy PRMR.

As shown in Table 17, MISO had nearly 13 GW of DR capability available in 2024, over 600 MW more than in 2023. Energy Efficiency (EE) participation in the PRA has remained very low after the 2020–21 auction, as discussed below.

MISO's demand response capability constitutes around ten percent of peak load, which is a much larger portion than in NYISO but slightly less than in ISO-NE. It exhibits varying degrees of responsiveness. Nearly 95 percent of MISO's DR are LMRs, which are capacity resources comprised primarily of (i) interruptible loads that were originally developed under regulated utility programs and (ii) behind-the-meter-generation. Aggregators of retail customers (ARCs) constitute a growing portion of MISO's LMRs in recent years.

34 Some DR may participate in more than one category, depending on the resource capability and responsibilities the resource is willing to accept, as explained below.

Table 17: Demand Response Capability in MISO and Neighboring RTOs
2022–2024

		2022	2023	2024
MISO[1]		**12,068**	**12,311**	**12,978**
	LMR-BTMG	4,169	4,129	4,143
	LMR-DR	7,543	7,695	8,109
	LMR-EE	0	5	23
	DRR Type I	582	521	692
	DRR Type II	127	79	75
	Total Cross-Registered as LMR	*416*	*201*	*210*
	Emergency DR	529	686	788
	Total Cross-Registered as LMR	*466*	*603*	*643*
NYISO[2]		**1,234**	**1,294**	**1,435**
	Special Case Resources - Capacity	1,231	1,282	1,433
	Emergency DR	3	12	2
	Day-Ahead DRP	0	0	0
ISO-NE[3]		**4,076**	**3,798**	**3,674**
	Active Demand Capacity Resources	466	438	431
	Passive Demand Resources	3,610	3,360	3,243

* All units are MW.
1 Registered as of July for 2024 and 2023, December for 2022.
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 2024. Source: ISO-NE Monthly Market Reports.

A second category is Demand Response Resources (DRRs) that can participate in MISO's capacity, energy, and ancillary services markets. A third category is Emergency Demand Response (EDR). Currently, resources may cross-register as LMRs and DRRs or EDRs, although MISO has filed to eliminate cross-registration in 2025.

LMRs

LMRs are planning resources that sell capacity and, thus, have an obligation to curtail during emergencies. MISO can only deploy these resources during a declared emergency. Many of these legacy demand-side programs are administered by regulated utilities, such as interruptible load and direct load control programs that target retail customers. They also include behind-the-meter generation (BTMG). They do not submit economic offers, but LMR deployment triggers MISO's emergency offer floor pricing mechanism. In the PRA, MISO classifies interruptible load resources as LMR-DR and BTMG resources as LMR-BTMG. As shown in Table 17, almost all the DR in MISO participate as emergency resources, mainly in the LMR category.

Demand Response Resources

DRRs are a category of DR that are assumed to be able to respond to MISO's real-time curtailment instructions. As Table 17 shows, this category comprises only a small portion of

MISO's total DR capability. These resources can participate in energy, ancillary services, and capacity markets. Most DRRs opt to participate in the capacity markets as LMRs, which lessens the likelihood of curtailment during an emergency because EEA1 events do not call for LMR curtailment. DRRs are further divided into two subcategories:

- Type I: These resources can supply a fixed, pre-specified quantity of energy or contingency reserve through physical load interruption. These resources can qualify as Fast-Start Resources and set price in ELMP.[35]
- Type II: These resources can supply varying levels of energy or operating reserves on a five-minute basis and are eligible to set prices, just like generating resources.

Aggregators of Retail Customers (ARCs) and Load-Serving Entities (LSEs) are eligible to offer DRR capability into the energy and ancillary services markets. DRR Type II resources can currently offer all ancillary services products, whereas DRR Type I units can provide all products except regulating reserves on account of their fixed-quantity demand reduction offers.

DRR Type I resources accounted for almost all of DRR scheduling in 2024. The scheduling of these resources fell sharply in mid-2022 after we identified significant conduct issues that led two of the largest participants to cease participation. We discuss these issues in subsection B. DRR Type I scheduling increased by 30 percent in 2024, and this was largely due to the registration of single large resource.

Emergency DRs

The third category of DR is Emergency Demand Response (EDR), which totaled 788 MW in 2024, an increase of nearly 15 percent from 2023. EDRs do not have a must-offer requirement unless they are cross-registered and cleared as LMRs in the PRA. DR resources that clear MISO's PRA can offer as EDRs rather than LMRs during emergencies. These resources specify their availability and costs in the day-ahead market. If an emergency ensues in real time, MISO selects EDR offers in economic merit order based on offered curtailment prices up to $3,500 per MWh. EDRs that curtail are compensated at the greater of the prevailing real-time LMP or their offered costs (including shut down costs) for the verifiable demand reduction provided. Unlike LMRs, EDRs can set prices with their offers during emergencies.

Finally, DR resources may count toward fulfillment of an LSE's PRMR if the resource can curtail load within 6 hours and is available during the summer months. These resources are accredited based on their availability throughout the planning year.

MISO did not call upon LMRs between 2007 and 2016. However, beginning in 2017, LMRs have become increasingly important in both planning and operations during emergency events.

35 A resource can qualify as a Fast-Start Resource provided the DRR Type I resource can curtail demand within 60 minutes and offers a minimum run time of less than or equal to one hour.

From April 2017 through December 2022, LMRs were deployed nine times in MISO South and four times in MISO Midwest. The most recent deployment occurred in December 2022 during Winter Storm Elliott, when MISO called on LMRs to provide support to a neighboring system that was shedding load.

B. Gaming and Manipulation Concerns related to Demand Response Resources

DRR Participation in Energy and Ancillary Services Markets

Payments to DRRs fell 34 percent in 2022 as resources that we had investigated and referred to FERC for market manipulation ceased participation and the payments to DRRs fell even further to just $3.2 million in 2023 and $4.8 million in 2024. Our investigation began in 2021 after we observed the DRR settlements increased significantly. The results raised significant concerns regarding the market design and rules, the inefficient incentives they provide, and the resulting participant conduct. We identified two types of problems with the settlement rules and participants' conduct.

Payments for artificial "curtailments". These are payments for energy that the participant never intended to consume. For example, consider an industrial facility registered as DRR with a peak load of 100 MW that will be offline for maintenance. Such a DRR could offer 100 MW of "curtailments" as a price-taker (at a very low price) even though its planned consumption was zero. Hence, the resource will be scheduled and paid the prevailing LMP for providing nothing.

Inflating the baseline level. Hours when curtailments are scheduled are not included in the baseline calculation because, presumably, the consumption in these hours is less than normal. Some participants have inflated their baseline by offering as a price-taker in almost all hours, which will cause their curtailment offer to be scheduled and the hour to be excluded from the baseline. The participant can then simply not offer the curtailment when its load is highest, causing the baseline to substantially exceed the participant's typical consumption for the DRR resource. Having established the inflated baseline, the participant can then return to offering curtailments as a price-taker when consuming at typical levels and be paid for the difference between the peak load level and the typical load level.

These two strategies accounted for the vast majority of payments to DRR Type 1 resources in 2021 and 2022. The two market participants who engaged in these strategies both settled with FERC in 2023 and 2024. In 2023, the DRR provider engaged in the first strategy agreed to a settlement of more than $35 million. In 2024, the DRR provider engaged in the second strategy agreed to a settlement of more than $66 million. These cases illustrate the inherent problems with allowing demand to participate on the supply side of the market.

Based on these results, we had recommended that MISO revise its DRR rules and Tariff provisions to provide efficient incentives and to ensure that all payments made to DRRs result in real curtailments. MISO filed proposed changes consistent with these recommendations in early 2025 that we believe will address these concerns.

In addition to market manipulation concerns in the energy and ancillary services markets, we have concerns that large point-specific loads, such as data centers and crypto-mining loads, may raise substantial market power concerns in the future. These loads are interconnecting to MISO at a fast rate and given their locations, some may substantially affect key transmission constraints. We are evaluating changes to Module D of the Tariff that would provide market mitigation measures to prevent these loads from exercising market power in MISO.

Gaming and Manipulation Concerns related to LMRs

We have had concerns for some time that the qualification and testing process to register LMRs is too lax and invites fraudulent activities. Some of these concerns have arisen from investigations that we have performed and conduct that we have referred to FERC enforcement. In 2024 and early 2025, FERC took enforcement actions against two separate ARCs that fraudulently enrolled and cleared LMRs in MISO’s capacity market without the end-use customer’s knowledge and consent. In addition, a large share of MISO’s LMRs have been registered without demonstrating through a real test that it can provide the curtailments being claimed but instead submitting “mock test” data. We believe the allowance in MISO’s tariff of mock tests has invited some LMRs to inflate their curtailment capabilities.

In 2025, we have been working with MISO to develop significant changes to LMR participation, testing, and accreditation rules, including creating two separate categories – LMR Type 1 and LMR Type 2 – and eliminating the ability for DRs to cross-register across products. MISO’s proposal will eliminate mock testing and tighten the rules for testing. The proposed changes will also align the LMR accreditation value with the DLOL methodology that will be implemented in the 2028–2029 Planning Year. MISO is making multiple filings with these changes, two of which were made in early 2025 and the last to be made in June.

C. Energy Efficiency in MISO’s Capacity Market

MISO allows energy efficiency (EE) to provide capacity. The quantity of EE participating in the PRA grew rapidly until the 2021–22 PRA, when the sole participating provider of EE was disqualified. Table 18 summarizes the EE quantities over the past five PRAs. After the disqualification described below, the quantity has remained equal to or close to zero.

In contrast to other LMRs, EE measures do not provide a dispatchable product and do not provide any other operating flexibility to assist MISO in maintaining reliability during emergency events. The IMM performed an audit of EE capacity in 2021. Based on this audit, we found the registered EE resources did not actually reduce MISO’s peak demand, and their capacity accreditation grossly overstated their reliability value. MISO validated these findings and ultimately disqualified the audited EE participant from participating in the 2021–22 PRA. In the 2024–25 PRA, a small amount of EE participated in and cleared MISO's capacity auction.

Table 18: Growth of Energy Efficiency in MISO

Planning Year	Enrolled Qty	Net Sales	Offer MW	Cleared/FRAP
2018/19	173	0	173	173
2019/20	312	0	312	312
2020/21	650	0	650	650
2021/22	0	0	0	0
2022/23	0	0	0	0
2023/24*	5.5	0	5.5	5.5
2024/25*	22.5	0	22.5	22.5

* Average of four seasons.

In December 2024, FERC had similar findings to the IMM's audit findings and issued an Order to Show Cause against the EE provider in multiple RTO markets, including MISO. FERC's show-cause order seeks a record penalty of nearly $1 billion. MISO acted quickly on our recommendation to disqualify this provider from the MISO capacity market, so the vast majority of the proposed penalty was associated with the provider's capacity sales in PJM over a number of years. PJM recently filed to eliminate EE from its capacity markets and FERC approved that change.

We recommend MISO also eliminate EE resources from its capacity market. We believe that EE resources should not be qualified to participate in the capacity market for three reasons:

- *EE Payments are Inefficient*. Making payments to customers directly or to intermediaries is not efficient because customers already have efficient incentives to make energy-efficiency investments. The savings they receive via lower electricity bills include the energy and capacity costs of serving them.
- *EE Capacity Values are Highly Uncertain*. It is not possible to accurately calculate how much the load has been reduced by EE in peak hours because it is based on an array of speculative assumptions. This uncertainty regarding their capacity value is why EE is not comparable to any other capacity resources since they can be tested and verified.
- *Cost Shifting Concerns.* The existing program can result in sizable cost shifting by causing other LSEs to pay for EE capacity payments that are benefiting one LSE. To avoid cost shifting, an LSE must control for the effects of the EE by explicitly grossing up their forecasts to counter the effect of EE, but they are not required to do so.

For these reasons, it would be best to simply eliminate MISO's EE program.

X. RECOMMENDATIONS

Although MISO's markets continued to perform competitively and efficiently in 2024 overall, we recommend a number of improvements in MISO's market design and operating procedures. These thirty-four recommendations (including 4 new ones) are organized by the aspects of the market that they affect:

- Energy and Operating Reserve Markets and Pricing: 7 total, 1 new
- Transmission Congestion: 9 total, 2 new
- Market and System Operations: 11 total, 1 new
- Resource Adequacy and Planning: 7 total

Thirty of the recommendations were recommended in prior *State of the Market* Reports. This is not surprising because some recommendations require substantial software changes, stakeholder review and discussions, and regulatory filings or litigation regarding Tariff changes.

MISO has addressed five of our past recommendations since our last report, which we discuss at the end of this section along with one retired recommendation because it has been supplanted by Order 881. For any recurring recommendations, we include a discussion of the progress MISO has made to date and the next steps required to fully address the recommendations.

A. Energy and Operating Reserve Markets and Pricing

Many of MISO's reliability needs are addressed through its operating reserve requirements that ensure resources are available to produce energy when system contingencies occur. However, to the extent that MISO has system needs that are not reflected in the operating reserve requirements, MISO may commit resources out-of-market that require a guarantee payment to recover their as-offered costs. As a general matter, MISO's market requirements should reflect its operating needs to the maximum extent feasible to allow the markets to satisfy and price these needs efficiently. The recommendations in this subsection are intended to improve this consistency between market requirements and operating requirements.

2024-1: Modify RDT demand curve steps and RPE binding limits

The RDT constraint limits transfers between MISO's Midwest and South subregions. Maximizing the value of this transfer capability is key to efficient market operations. In 2024, the RDT bound in more than one quarter of real-time market intervals, separating subregional LMPs by an average of more than $3 per MWh.

To prevent unmodeled flows from violating its contract limit, MISO typically derates the RDT in real time. These derates can cause widespread price increases and result in MISO utilizing only

84 percent of the contracted capability in its dispatch when the RDT binds. We recommend MISO modify the RDT Transmission Constraint Demand Curve (TCDC) by adding lower-valued steps and raising the energy plus STR limit to align with the highest penalty step on the TCDC. These demand curve adjustments will increase RDT utilization when the value of subregional transfers is high and reduce the burden on MISO operators to constantly monitor and adjust the RDT limit in the real-time market.

Status: This is a new recommendation.

2023-1: Align aggregate pricing nodes from the FTR market through real-time

MISO prices and settles with market participants at individual nodes, as well as at locations that are aggregations of individual nodes. In general, aggregates such as market pricing hubs raise no concerns and provide value to market participants as long as the definitions of the aggregate locations are stable between the FTR, day-ahead, and real-time markets.

While most aggregate pricing nodes have stable definitions, some ARR Zones, interfaces, and combined-cycle nodes vary significantly. Differences between the FTR and day-ahead modeling often arise when new loads, like high-intensity data centers, come online or existing loads diverge from past consumption patterns. The most problematic definition changes from day-ahead to real-time result from dead-bus modeling on offline generators included in aggregate price nodes. Modeling differences raise significant concerns because they:

- Cause the settlements in the day-ahead and real-time market to be inconsistent, exposing the market to shortfalls or requiring uplift to resolve the inconsistency;
- Alter the property rights conveyed by positions in the FTR market; and
- Introduce potential gaming opportunities that could be substantial as new loads enter the market that can cause expected inconsistencies.

To address these concerns, we recommend that MISO implement changes to better synchronize the definitions of the aggregate pricing nodes from the FTR market through the real-time market.

Status: MISO agrees with the IMM's concerns related to modelling differences between the FTR, day-ahead, and real-time markets. MISO plans to evaluate the proposed solution to synchronize the definitions of the aggregate pricing nodes from the FTR market through the real-time market. This evaluation has not been scheduled.

Next Steps: MISO should complete their evaluation and work to better synchronize the definitions of the aggregate pricing nodes from the FTR market through the real-time market.

2023-2: Enforce STR requirements in the load pockets

MISO continues to incur substantial uplift costs to satisfy VLR requirements in key load pockets. Because these commitments are made out-of-market, prices cannot signal the need for additional resources in these pockets. This is particularly problematic under conditions when these pockets are short of the supply necessary to satisfy the energy and VLR requirements. During Winter Storm Heather, the load pocket in east Texas was nearly short of energy, which was not efficiently reflected in prices.

To address these concerns, we recommend that MISO develop and enforce STR requirements in load pockets that have VLR needs. This will allow the markets to: a) help maintain reliability in these load pockets in the short term, and b) provide more efficient economic signals to invest in generation and transmission in the load pockets in the long term.

Status: MISO shares IMM's concerns regarding out-of-market commitments for voltage and local reliability (VLR) requirements in key load pockets, but MISO has identified additional factors to be evaluated before implementing STR requirements in load pockets for VLR: policy and settlement complexities, computational limitations, long lead time unit management, and zonal alignment concerns between VLR and reserve zone definition.

Next Steps: MISO should complete their evaluation and determine if there are any factors that would impede enforcing STR requirements in load pockets that have VLR needs.

2021-2: Evaluate reintroducing LMR curtailments as STR demand in pricing models and UDS

In studying emergency events that have occurred in MISO when it has deployed large quantities of LMRs, we have found that MISO emergency pricing often does not establish efficient prices. Currently, LMRs are modeled in the ELMP pricing engine as resources with offer price floors of $500 or $1000 per MWh that can be dispatched down and replaced by other resources. This process determines whether the LMRs are needed and should set prices.

Because the ELMP model is a dispatch model that honors resources' ramp rates, it is often not possible to replace a large volume of LMRs within a single dispatch interval with non-emergency ramping generation. This causes the LMRs to appear to be needed and set prices long after MISO's resources are sufficient to replace them by ramping up. This concern could be addressed by treating the LMRs as an operating reserve demand in the ELMP model, which would eliminate the need for other resources to be able to ramp up to replace them in the ELMP model. In this case, if the LMRs are needed, the ELMP model will register a reserve shortage and set prices accordingly at shortage levels.

Importantly, once the LMRs are no longer needed, they would stop setting real-time prices simply because other resources are ramp constrained. Therefore, we recommend that MISO reintroduce LMR curtailments as STR demand in its ELMP model to determine when they should set prices during emergency conditions.

Status: MISO has agreed on the problem and proposed an alternative solution. MISO plans to prioritize studying these alternatives. This issue is included in MISO's 5-year plan.

Next Steps: MISO should complete its study and prototyping of software solutions and determine final approach and implementation schedule.

2020-1: Develop a real-time capacity product for uncertainty

We recommend MISO evaluate the development of a real-time capacity product in the day-ahead and real-time markets to account for increasing uncertainty associated with intermittent generation output, NSI, load, and other factors. Such a product should be co-optimized with the current energy and ancillary services products. These capacity needs are currently procured out-of-market through manual commitment by MISO's operators. Clearing this product on a market basis would allow MISO's prices to reflect the need for commitments and reduce RSG. The resources that would supply this product would include online resources and offline resources that are available to respond to MISO's uncertainties (e.g., those that can start within four hours).

The benefits of such a product will increase as MISO's reliance on intermittent resources increases. The transition in the generating fleet will increase supply uncertainty, which will in turn increase the real-time capacity needs of the system and the costs of satisfying them. Hence, we recommend MISO establish a real-time capacity product or uncertainty product that would be implemented under MISO's current market software.

Status: MISO agrees with the IMM's description of the issue. MISO has made enhancements to its Ramp and Short-Term Reserve products, many of which are expected to help with managing uncertainty. MISO also has other efforts underway including improved operator tools and forecasting. MISO plans to further evaluate the need for a new uncertainty product and will continue working on improving the LAC process to address uncertainty.

Next Steps: While we agree that enhancements to the Ramp and Short-Term Reserve products will help, MISO should complete its evaluations of an uncertainty product and prioritize its design and implementation.

2012-3: Remove external congestion from interface prices

When MISO includes congestion associated with external constraints in its interface prices, this congestion pricing is inefficient because it is generally not accurate and duplicates the congestion pricing by the external system operator. In addition, external operators provide MISO no credit for making these payments, neither through the TLR process nor through the M2M process. Hence, they are both inefficient and costly to MISO's customers. To fully address these concerns, we continue to recommend that MISO eliminate the portions of the congestion components of each of MISO's interface prices associated with the external constraints.

Status: There is no change in status in 2024. This recommendation was originally made in our *2012 State of the Market Report.* MISO agrees that interface pricing would be improved by eliminating external congestion on all interfaces. Nonetheless, there has been no progress on this recommendation and MISO has no plans to address this recommendation until after implementation of the MSE. We continue to recommend that MISO take any necessary steps to remove external congestion from its interface prices at all interfaces except the PJM interface, which would require an agreement with PJM to abandon the current "common interface" approach. These changes will improve the efficiency of MISO's interface prices and its interchange transactions. MISO has said that it would evaluate the non-market interfaces as part of the MSE.

Next Steps: MISO should develop the work plan necessary to modify its interface prices as part of its MSE because it is essential to include this capability in the MSE requirements.

2012-5: Introduce a virtual spread product

Virtual traders arbitrage congestion-related price differences between the day-ahead and real-time markets, which improves the performance of the markets. They do this by clearing offsetting virtual supply and demand transactions, which results in taking a position on the flows over a constraint without taking any net energy position. Because both transactions must clear to create an energy-balanced position, they are generally offered price-insensitively. A virtual spread product enabling participants to arbitrage congestion in a price-sensitive manner would be much more efficient. Participants offering such a product would specify the maximum congestion between two points they are willing to pay. This would reduce the risk participants currently face when they submit a price-insensitive transaction.

Status: There is no change in status in 2024. This recommendation was originally proposed in our *2012 State of the Market Report*. In 2018 MISO indicated that technical feasibility was a concern under the current systems. The status of this project is inactive pending completion of the MSE, and it is deferred beyond the 5-year action plan.

Next Steps: The IMM continues to encourage MISO to reconsider this recommendation.

B. Transmission Congestion

Transmission congestion arises when the limitations of the network prevent the least cost use of resources. MISO optimizes the dispatch of resources to keep the flows over the network below the limits of each of the transmission facilities. The marginal costs of managing the flows when transmission constraints bind is reflected in MISO's day-ahead and real-time LMPs, providing efficient short and long-term incentives for existing and new resources. Given the sizable costs of transmission congestion in MISO, improving the utilization of the transmission system should be among the highest priorities, which is the focus of the recommendations in this section.

2024-2: Shift a large share of transmission capability from the annual ARR allocation and FTR auction to seasonal and monthly auctions

MISO's seasonal and monthly FTR auctions often result in inefficient pricing outcomes where MISO overpays for counter-flow and underprices incremental capacity. This indicates a lack of liquidity in these auctions that may be partially attributable to low participation by auction revenue rights holders. We have also observed that transmission owners frequently report outages much later than currently required for the annual FTR auction. Delinquent outage reporting causes constraints in the annual FTR auction to be inaccurately modeled and can cause the FTRs to be oversold.

To improve FTR market performance, we recommend three fundamental changes that address these issues:

1. Shift a substantial portion of the transmission capability from the annual FTR auction to seasonal and monthly auctions.
2. Institute an ARR allocation process in the seasonal and monthly FTR process.
3. Consider methods to allocate a larger share of the remaining unallocated transmission capability to transmission customers based on customers' load and generation.

These changes will improve the performance of the FTR market by allocating and selling more of the capacity in timeframes when outages are more fully known and incorporated. It will also increase liquidity by facilitating participation by transmission customers in the near-term auctions, giving them the opportunity to submit prices (i.e., reservation prices) at which they are willing to sell capability allocated to them. We believe this will improve the convergence of FTR prices in the seasonal and monthly auctions with the ultimate value of the FTRs.

Status: This is a new recommendation.

2024-3: Limit acceptance of transferred M2M flowgates to those where MISO has more effective relief and require proper use of the relief request software

As part of the market-to-market (M2M) coordination process MISO and its partners can agree to transfer monitoring responsibilities of a flowgate to the "non-monitoring RTO" (NMRTO). Under this "reverse role" flowgate configuration, the RTO accepting control acts as the monitoring RTO (MRTO), modeling the physical limit of the flowgate in its market dispatch software and requesting relief from the NMRTO.

The reverse role configuration can improve efficiency and reliability when the neighboring RTO has significantly more effective generation relief than the NMRTO. However, these potential efficiency gains are dependent on the RTO accepting the transferred flowgate and requesting sufficient relief request quantities—requesting too little relief can cause significant shadow price separation and increase the total congestion costs.

MISO has accepted and managed a large number of flowgates transferred from SPP. Our analysis of these reverse role flowgates raises two concerns. First, MISO has sometimes accepted the transferred constraints from SPP for which MISO lacks sufficient economic relief. Second, SPP has requested that MISO use the relief request software in a manner that predictably understates the quantity of relief it requests from SPP. This leads to poor shadow price convergence, which has resulted in much higher costs for MISO and its customers. For flowgates that bind persistently, these misaligned price signals can also flow through to the day-ahead market where settlement impacts are magnified.

To address these concerns, we recommend that MISO:

1. Limit its acceptance of reverse role M2M flowgates from SPP to only those where MISO has significantly more effective relief than SPP; and
2. Require appropriate use and parameterization of the relief request software for all reverse role flowgates MISO agrees to monitor.

Status: This is a new recommendation.

2023-3: Develop tools to recommend decommitment of resources committed in the day-ahead market

As congestion has increased in the MISO markets, we have observed with increasing frequency cases where substantial congestion relief could be achieved by decommitting resources that were scheduled in the day-ahead market. Because such cases produce very low and often negative prices, the owner of the resource would often benefit substantially by allowing the resource to be decommitted. Additionally, it would generally improve reliability by making severely binding constraints easier to manage. Unfortunately, such participants lack the information necessary to determine when their resources should be decommitted. MISO could optimize such decisions by allowing its LAC model to consider such decommitments. Hence, we recommend MISO implement changes in the LAC and settlement processes to allow day-ahead committed resources to be decommitted when significantly uneconomic in real time.

Status: MISO agrees there are cases where economics and reliability would improve by decommitting day-ahead scheduled resources.

Next Steps: MISO will work with the IMM to evaluate this recommendation, but this evaluation has not been planned yet.

2022-1: Expand the TCDCs to allow MISO's market dispatch to reliably manage network flows

During a number of storm events in 2021 and 2022, MISO experienced operational challenges requiring extraordinary operator actions to manage network flows. During both transmission and capacity emergencies, the current TCDCs limit the ability of MISO's market dispatch to manage transmission congestion. During capacity emergencies, the value of energy and reserves under the ORDC can prevent the dispatch model from reducing output when needed to manage network flows because the value of managing the transmission constraint is not high enough. Likewise, when the RDT or other constraints are violated, the dispatch model may not move generation as needed to manage the flows over other constraints. This has often compelled MISO operators to manually dispatch generation to reduce flows on overloaded constraints, which is costly and distorts market outcomes.

Therefore, we recommend MISO add higher segments to the TCDCs to allow the dispatch model to limit excessive violations. MISO should also improve its procedures to increase the TCDCs for a constraint when the violations raise reliability concerns or are sustained. Additionally, uncertainty regarding network flows has often caused operators to derate transmission constraints. Adding lower-priced segments to the TCDCs to account for the value of holding back transmission capability to manage uncertainty could be valuable and we recommend MISO consider this as an alternative to its current approach to lowering transmission limits.

Status: MISO agrees that potential improvements can be made related to transmission constraint management. MISO has made progress in being more proactive in making TCDC overrides and in reducing out-of-market actions to manage difficult constraints, resulting in more efficient market outcomes. However, MISO has not yet begun assessing these recommended changes in the TCDCs but plans to do so to improve congestion management, particularly during transmission or capacity emergencies.

Next Steps: Develop a workplan to evaluate and implement improved TCDCs.

2021-1: Work with TOs to identify and deploy economic transmission reconfiguration options

We have recommended MISO develop resources and processes to analyze and identify economic reconfiguration options for managing congestion in coordination with the TOs. Transmission congestion continues to be primarily managed by altering the output of resources in different locations. However, it can also sometimes be highly economic to alter the configuration of the network (e.g., opening a breaker). Currently, this is employed by Reliability Coordinators to manage congestion for reliability reasons under the procedures established in consultation with the transmission owners impacted by the reconfiguration. Such procedures could be expanded to relieve costly binding constraints that are generating substantial congestion costs. In the past few years, MISO has implemented several economic reconfigurations that have produced significant benefits.

Status: MISO agrees with this recommendation and has been working with the TOs through the Reconfiguration for Congestion Cost Task Team (RCCTT). While MISO has developed a process to accept, evaluate, and implement recommended reconfigurations, MISO has not yet implemented a proactive internal process to identify and evaluate economic reconfigurations. Hence, the current process can be enhanced in two areas: 1) MISO should develop a robust process for itself to identify and analyze reconfiguration options in both the real-time and the planning horizon; and 2) MISO should actively review and evaluate TO responses as indicated in the RCCTT process document. The same criteria should apply for evaluating reliability-based reconfigurations and economic reconfigurations. To date, some valuable options have been denied by TOs in the absence of verified concerns or have failed to be evaluated in a timely manner.

Next Steps: MISO has indicated it will evaluate processes to identify and evaluate economic reconfiguration itself. MISO should undertake this development as soon as practicable and seek comparability with reliability-based reconfigurations.

2019-1: Improve the relief request software for market-to-market coordination

A key component of successful market-to-market (M2M) coordination is optimizing the amount of relief that the monitoring RTO (MRTO) requests from the non-monitoring RTO (NMRTO). If the request is too low, the NMRTO will not provide all its economic relief, resulting in higher congestion costs and potentially higher settlement costs for the NMRTO. If the request is too high, it can result in congestion oscillation that can raise costs. We find that the current relief request software does not always request enough relief from the NMRTO. This can occur because the current software does not consider the shadow price differences between the RTOs.

To address these issues in the short term, we continue to recommend that MISO base relief requests on the RTOs' respective shadow prices and implement an automated means to control constraint oscillation. In the long term, MISO should use dynamic transmission constraint demand curves to reflect the actual relief provided by the NMRTO in the dispatch of the MRTO.

Status: MISO agrees with the issue. In 2021, MISO and SPP implemented a near-term tool using "predicted" UDS flow to address oscillations, but we had noted it had not yet been configured properly to be effective and the IMM has continued to observe configuration issues in 2024. Unfortunately, it is not clear whether the current tool will be effective if implemented properly, and it is not likely to increase relief requests when they are too low. PJM and MISO are partnering with Temple University, NREL, and New Mexico State University to submit for a DOE grant on predictive and adaptive M2M coordination for efficient congestion relief. This is intended to investigate the power swings logic on this seam. MISO and the IMM continue discuss convergence metrics for flowgates to review.

Next Steps: MISO should continue to work to ensure the configuration and use of the current tool is consistent with the design to properly assess its effects. After making this assessment, MISO should determine whether a more efficient solution is warranted and work with the IMM to identify improvements in the relief request software needed to address this recommendation.

2019-2: Improve the testing criteria defining market-to-market constraints

The original intent of this recommendation was to identify constraints that will benefit from M2M coordination or for which the NMRTO's market flows are a substantial contributor to the congestion. Currently, a M2M constraint will be identified when the NMRTO has:

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

These two tests are not optimal in identifying constraints that would benefit from coordination because they do not consider the economic relief the NMRTO will likely have available. As detailed in the body of the report, our analysis shows that alternative tests would be much better at identifying the most valuable constraints to define as M2M constraints. Accordingly, we recommend that MISO work with PJM and SPP to introduce a test based on the available flow relief that can be provided by the NMRTO to replace the current five percent shift factor test.

Status: MISO agrees on the issue and has indicated that it will evaluate the IMM's recommended solutions and their effects on the administration of JOAs. However, MISO indicates that MISO, SPP, and PJM have prioritized the Freeze Date Firm Flow Entitlement (FFE) updates.

Next Steps: MISO has noted the testing criteria may be considered and implemented with mutual agreement with no Tariff changes. Hence, we recommend that MISO propose these changes to its JOA partners and pursue improvements.

2016-3: Enhance authority to coordinate transmission and generation planned outages

MISO is responsible for approving the schedules of planned transmission and generation outages. This approval process considers only reliability concerns associated with requested outages and not the potential economic costs. As a result, we have seen numerous cases where simultaneous generation and/or transmission outages in an electrical area have led to severe transmission congestion. In 2024, multiple simultaneous generation outages contributed to almost $540 million in real-time congestion costs, indicating large potential savings.

Most of the other RTOs in the Eastern Interconnect have limited authority comparable to the limits on MISO, with the exception of ISO-New England. ISO-New England does have the authority to examine economic costs in evaluating and approving transmission outages, an authority which has been found to have been very effective at avoiding unnecessary congestion costs. We recommend MISO expand its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages.

Status: MISO agrees with this recommendation and lists it as an Active item, but little progress has been made to date. While improvements have been made in evaluating the reliability and economic impacts of outages, MISO has not sought additional outage coordination authority. MISO indicates a white paper is still in development and economic considerations for outage coordination continue to be in the RAN work plan.

Next Steps: MISO should consider accelerating the process to address this recommendation and file for increased authority to coordinate outages.

2014-3: Seek joint operating agreements with neighboring control areas to improve congestion management and emergency coordination

As noted in prior years, the dispatch of the integrated MISO system has increased the frequency of TLRs called for constraints in TVA, AECI and IESO. TLRs result in substantial congestion costs, which could be mitigated and produce sizable benefits for MISO if it were to develop redispatch agreements with TVA and IESO. Under such agreements, the TLR process could be replaced with a coordination process that would allow MISO and its neighbors to procure economic relief from each other, which will lower costs and improve reliability. Additionally, coordination between MISO and its neighbors has been inconsistent during emergency conditions, as highlighted by events during Winter Storms Uri and Elliott. JOAs with each of MISO's neighbors can specify the emergency coordination each system will provide and the associated settlements between the areas.

Status: Limited progress on this recommendation was made in 2024. MISO agrees with this recommendation and has reached out to both IESO and TVA regarding agreements. IESO has indicated they are working on major system changes and are postponing further discussions. MISO is working on a balancing authority agreement with TVA and plans to start discussions on a JOA once the BA agreement and updates to the Congestion Management Process (CMP) are complete. MISO also agrees that JOAs with other adjacent control areas to coordinate during emergencies would be valuable.

Next Steps: MISO should continue to attempt to negotiate redispatch agreements with TVA and IESO that will allow economic coordination and redispatch to efficiently manage congestion on their respective systems. Additionally, coordinated emergency procedures and settlements should be proposed with each of MISO's neighbors.

C. Market and System Operations

As discussed above, the efficient performance of the real-time market is essential to achieving the full benefits of competitive wholesale electricity markets, which includes satisfying the system's needs reliably at the lowest cost. MISO's real-time operators play an important role in this process because they monitor the system and make a variety of changes to parameters and other inputs to the real-time market and take operating actions to maintain reliability. Each of these actions can substantially affect market outcomes. The following recommendations seek to improve MISO's operating actions and real-time market processes.

2024-4: Improve constraint management and dead bus criteria for Forced Off Asset Events

On July 8-9, 2024, Hurricane Beryl impacted Texas and Louisiana, causing extensive forced transmission outages that disconnected most loads in the Southeast Texas (SETEX) Load Pocket. Prices were volatile and inefficient in SETEX during the event and led to uplift costs allocated to loads market wide. While this event had similarities with Hurricane Laura, the impetus for the Forced Off Asset (FOA) provisions, Hurricane Beryl failed to qualify as an FOA Event.

When MISO declares a FOA Event, real-time prices are set equal to the day-ahead prices. This pricing prevents forced-off loads and generators from adverse settlement consequences, while limiting financial windfalls charged to the rest of the market. This event did not qualify because the FOA Revenue Inadequacy criteria are defined too narrowly and the dead bus criteria includes offline generators. To address this concern and apply the FOA provisions more appropriately, we recommend MISO limit the FOA dead bus criteria to only load buses and combine Revenue Inadequacy and Price Volatility Make-Whole Payments in the financial criteria for declaring an FOA Event.

<u>Status</u>: This is a new recommendation.

2023-5: Require descriptions in new or updated CROW tickets

Accurate outage reporting in MISO's CROW system is increasingly important because it informs the expectations of MISO's operators of the availability of resources and is now an integral component of the capacity accreditation and settlement rules. The information submitted in CROW is also essential for the IMM's monitoring of physical withholding and potential manipulation by deliberately misclassifying outages and derates.

Unfortunately, participants often provide limited or no information when scheduling or extending outages and derates in the CROW system. We recommend MISO modify its rules and systems to require adequate descriptions when suppliers enter new CROW tickets or update existing tickets. At the same time, we recommend higher standardization with information that participants provide to NERC on Generating Availability Data System (GADS).

Status: MISO updated the cause codes in CROW (control room operating window) last year including removal of the 'Other' option. The cause code is a required field, but the requester notes, description and reason fields remain optional.

Next Steps: MISO should make the optional fields listed above mandatory and consider requiring outage codes that match the GADS reporting.

2022-3: Improve excess and deficient energy penalties to improve generators' incentives to follow MISO's dispatch instructions

Currently, generators do not accrue excess or deficient energy penalties until they exhibit such deviations for four consecutive intervals. Even after this time, the current penalties do not ensure that generators will benefit by following MISO's dispatch instructions. This is particularly concerning when resources load binding transmission constraints. In this case, UDS assumes all dispatch instructions will be followed, and the flows will be consistent with the dispatch. If generators do not follow the instructions, the constraint flows can substantially exceed the transmission limits. This raises substantial economic and reliability concerns.

To address this, we recommend that MISO implement excess and deficient energy penalties based on generators' LMP congestion components. The application of the penalty could begin in the first interval that a generator deviates and increases in size the longer the deviations persist.

Status: MISO agrees with this issue and is implementing an Uninstructed Deviation Enhancement (UDE) dispatch flag to clarify when intermittent resources are loading a transmission constraint and must follow the dispatch instruction. However, MISO has not developed settlement provisions to give suppliers an incentive to follow the dispatch instruction. MISO agrees that this type of penalty would improve suppliers' incentives to follow dispatch instruction.

Next Steps: MISO should develop settlement provisions, including a proposed penalty to discuss with stakeholders and file in 2025.

2021-3: Evaluate and reform MISO's unit commitment processes

In 2021, we observed increased out-of-market commitments by MISO and associated RSG costs. During 2022, we worked with MISO to identify commitments that were not ultimately needed to satisfy MISO's energy, operating reserves, or other reliability needs. We also identified the assumptions, procedures, and forecasting issues that have led to these unneeded commitments.

In addition to raising RSG costs borne by its customers, excess commitments depress real-time prices and result in inefficiently lower imports from neighboring areas, inefficiently lower day-ahead procurements and resource commitments, and distorted long-term price signals. Therefore, it is important to minimize excess out-of-market commitments and the accompanying RSG costs. We recommend that MISO:

1. Implement the identified improvements in its tools, procedures, and the criteria used to make out-of-market commitments.
2. Ensure that operators can observe the relevant offer costs that MISO will guarantee associated with each out-of-market commitment.
3. Update VLR operating guides in a timely manner when resources enter or exit the VLR area or transmission upgrades are made that affect the VLR area.

Status: MISO agrees with this recommendation and made substantial progress in 2024. MISO continued working with the IMM to implement improvements to its procedures and the LAC process. MISO's efforts are coordinated under the uncertainty management effort at MISO and MISO has committed to continuing this work in 2025.

Next Steps: The IMM will continue working with MISO on specific recommendations to improve the out-of-market generator commitments.

2021-4: Develop a look-ahead dispatch and commitment model to optimally manage fluctuations in net load and the use of storage resources

As reliance on intermittent resources grows, the need to manage fluctuations in net load (load less intermittent output) will grow. Because these demand changes occur in multi-hour timeframes, managing them efficiently requires the market to optimize both the commitment and dispatch of resources over multiple hours. This multi-hour optimization will also allow the markets to optimize the scheduling of interchange and energy storage resources. These resources will play a key role in managing the ramp demands of an intermittent-intensive system.

Therefore, we recommend that MISO begin developing a look-ahead dispatch and commitment model that would optimize the utilization of resources for multiple hours into the future. This is a long-term recommendation that will require substantial research and development. However, we believe this will be a key component of the MISO markets' ability to economically and reliably manage the transition of its generating portfolio.

Status: MISO has indicated general agreement, and MISO recognizes that the need for this capability may increase in the future to manage storage resources. MISO has included this in its R&D prioritization through the 'Look-Ahead Dispatch (LAD) Exploration' study.

Next Steps: MISO should prioritize its LAD Exploration study and expedite the R&D necessary for design and implementation of a look-ahead dispatch and commitment model.

2020-2: Align transmission emergency and capacity emergency procedures and pricing

Capacity emergencies that cause MISO to progress through its EEA levels and associated procedures produce very different operational and market results than transmission emergencies. These differences are sometimes justified because of different system needs. Often, however, insufficient supply in a local area (i.e., a local capacity deficiency) will lead to transmission overloads as the real-time dispatch seeks to serve the load by importing power into the area. In these cases, the reliability actions and market outcomes should be comparable regardless of whether operators decide to declare a transmission emergency or a capacity emergency.

In the *2021 State of the Market Report*, we highlighted two declared emergency events—one a capacity emergency and the other a transmission emergency—which resulted in very different market outcomes and price signals. The divergence of the outcomes was a concern, and we continue to recommend MISO bring alignment between the two types of emergencies by:

1. Reviewing the emergency actions used during capacity emergencies and identifying those that could be applicable during transmission emergencies. As an example, this would include curtailing non-firm external transactions that could have provided relief for some of the transmission emergencies that occurred during Winter Storm Uri.
2. Raising TCDCs for violated constraints as the emergency escalates, allowing prices in the pocket to approach VOLL as MISO moves toward shedding load to relieve the constraint.
3. To the extent that a local reserve zone is defined in the area, increasing the Post Reserve Deployment Constraint Demand Curves to achieve efficient local emergency pricing.

<u>Status</u>: MISO agrees emergency procedures can be better aligned and should include all appropriate reliability actions and tools for managing the system under different types of emergencies. MISO indicates this effort is active, but no progress was made in 2024.

<u>Next Steps</u>: The IMM and MISO continue to discuss the emergency procedures and supporting tools. MISO should develop specific procedures regarding how it will increase its TCDCs and Post Reserve Deployment Constraint Demand Curves to ensure efficient locational pricing during transmission emergencies. This includes establishing prices approaching VOLL in the constrained areas when load-shedding is deployed in a transmission emergency.

2019-4: Optimize CTS schedules every five minutes based on the RTOs' alternative real-time load scenarios

We have concluded that persistent sizable forecasting errors by MISO and PJM have hindered the use of CTS. These errors limit the potential effectiveness of CTS, clearing transactions that are uneconomic based on real-time prices or not clearing transactions that would have been economic. Given the timing of the forecasts and the resources necessary to improve them, we have little optimism that substantially improving the forecasts is possible. Additionally, MISO has reached a decision point on the current CTS. Significant costs must be incurred in the MSE project to rebuild this capability, and we do not believe this is a wise investment.

Hence, we recommend an alternative. The RTOs modify CTS to minimize joint production costs by clearing incremental transactions every five minutes using their real-time dispatch models. MISO, PJM and SPP solve their real-time dispatch models for multiple unique load scenarios. A simple optimization evaluating the production cost and interface price deltas between these scenarios could allow the RTOs to select the scenarios that effectuate the most efficient transfer level between these areas. Making more timely adjustments in each real-time interval would achieve large savings. These adjustments would also likely reduce ramp and reserve shortage-related price volatility, which has been increasing with greater renewable penetration.

Status: No progress was made on this recommendation in 2024. MISO continues to agree with the IMM that forecasts used in the 15-minute clearing have been inaccurate and that the IMM solution would improve accuracy and result in more efficient transactions.

Next Steps: Given the substantial benefits available from a well-functioning CTS process, we continue to recommend that MISO evaluate the software requirements for implementing this recommendation and begin discussing this proposal with both PJM and SPP.

2018-4: Clarify the criteria and improve the logging for declaring emergencies and taking emergency actions

Over the past few years, MISO has experienced a significant increase in the frequency of generation emergencies, primarily at the regional level. Based on our review of these events, we find that MISO's emergency declarations and actions have been inconsistent from event to event. This includes both the timing of the declarations and the forecasted regional capacity margins (the difference between the regional supply and demand). Hence, we recommend that MISO evaluate its operating procedures, tools, and criteria for declaring emergencies. This should include clarifying the criteria for making each emergency declaration and logging the factors that are the basis for operator actions.

Status: MISO agrees and continues to work with the IMM to identify and review changes to MISO's Emergency Operating Procedures related both to declaring emergencies and documenting the emergency actions taken. MISO also has a multi-phase project underway to improve its Capacity Sufficiency Analysis Tool, which is designed to provide more accurate situational awareness and improve decision-making prior to and during an emergency.

Next Steps: MISO has agreed to continue the collaborative work described above to improve the clarity of the procedures and the tools used to trigger the declarations of different levels and types of emergencies. Improving the logging of the emergency determinations and actions should be a high priority.

2017-2: Remove transmission charges from CTS transactions

CTS with PJM was implemented in October 2017. It promised substantial economic benefits by adjusting the scheduled interchange based on forecasted energy prices in the two RTO areas. We had advised the RTOs not to apply transmission charges or allocate costs to these transactions because they do not cause any of these costs. Nonetheless, MISO and PJM apply transmission reservation charges to these transactions when they are offered (not just when they are scheduled) and additional charges when they are scheduled. The reservation portion of charges are a substantial barrier to submitting CTS offers. Our analyses have shown that CTS transactions are unprofitable only because of the transmission charges.

We continue to recommend MISO eliminate its own charges. MISO should also eliminate the requirement that participants reserve transmission for CTS transactions since the RTOs can make interface adjustments by utilizing any available transmission capability.

Status: MISO agrees that CTS has not performed well and that the transmission reservation charges are a significant factor. This item remained inactive in 2024 and MISO does not anticipate any activity in 2025. MISO should consider this recommendation as it considers what changes to implement under the MSE.

Next Steps: MISO should reconsider its decision to suspend action on this recommendation.

2017-4: Improve operator logging tools and processes related to operator decisions and actions

Operator decisions in all the MISO functions, including the day-ahead and real-time markets, can significantly impact both market outcomes and reliability. While automated tools and models support most of the market operations, it is still necessary for operators to take actions outside of the markets. Although these operator actions are necessary, it is also critical both from a management oversight and a market monitoring perspective for the actions to be logged in a manner that enables oversight and evaluation. Operator actions can indicate market performance or design issues, and they can point to potential market improvements or procedural improvements that would lower overall system costs. Examples of operator adjustments include:

- Real-time adjustments to market load with the “load-offset” parameter, made to account for supply and demand factors that cause the dispatch model inputs to be inaccurate.
- Real-time adjustments to model inputs to LAC for wind and load to compensate for forecast errors.
- Adjustments to TCDCs to manage transmission constraints under changing conditions.
- Limit Control changes that alter the real-time limits for transmission constraints.
- Requests for M2M constraint tests and activations.

- Manual redispatch of resources that are made to satisfy system needs.
- Changes in operating status of generating units, including placing a unit "off-control," which causes the unit to receive a dispatch instruction equal to its current output.

Actions that impact settlements tend to be more completely logged. For example, manual generator commitments are well-logged because the reason and timing of the commitment are used by the settlement system to allocate RSG charges. However, other actions listed above are logged in a narrative field that is inconsistently populated and difficult to use for evaluation. Because these actions can have significant cost and market performance implications, we recommend MISO upgrade its systems and procedures to allow these and other operator actions to be logged in a more complete and detailed manner.

<u>Status</u>: MISO agrees with the importance of this issue and with the IMM recommendations. MISO has made improvements in logging features and procedures within the current MCS and has put more emphasis on training operators to facilitate clear and concise log entries. The *operating logging enhancement project* will provide further enhancements to the operator logging functionality in MCS.

<u>Next Steps</u>: The MISO Operations of the Futures Initiatives will include IMM recommendations and other needs identified through this effort. The next phase of the MCS rewrite project is focused on improving operator logging. Operator logging enhancements are continuing with additional functionality expected to be added in 2025.

2016-6: Improve the accuracy of the LAC recommendations and record operator response to LAC recommendations

MISO has developed and implemented a Look-Ahead Commitment (LAC) model to optimize the commitment and decommitment of resources that can start in less than three hours. MISO has improved the accuracy of the inputs to LAC and the demand curves for the market products in the LAC. We continue to recommend that MISO identify and address other sources of inaccuracies in the LAC model and develop logging and other procedures to record how operators respond to LAC recommendations.

<u>Status</u>: MISO generally agrees with this recommendation. In the past several years, MISO has made a number of specific improvements to both the LAC logic and operator displays. The LAC recommendations are substantially improved as a result. However, MISO frequently does not accept the LAC recommendations, particularly those recommended to manage congestion.

<u>Next Steps</u>: MISO should continue to improve the LAC recommendations and modify its processes to more consistently accept and implement the recommended actions. We also recommend that MISO improve its logging to document determinations that deviate from the LAC recommendations.

D. Resource Adequacy and Planning

Reasonable resource adequacy requirements and a well-functioning capacity auction are intended to facilitate efficient investment and retirement decisions. The efficiency of MISO's market signals has become increasingly important as planning reserve margins in MISO have fallen, particularly as evidenced in the capacity market shortage in the Midwest in MISO's 2022-23 planning resource auction. We have identified a number of critical issues that are undermining the economic signals provided by the MISO planning resource auctions. The impacts of these issues are mitigated to some extent by the fact that regulated utilities serve the load in a large portion of MISO. Hence, these utilities may invest in new resources and maintain existing units that are needed because they receive supplemental revenues through the state regulatory process.

However, MISO also relies on a large quantity of supply owned by competitive unregulated companies that rely entirely on MISO's wholesale market price signals to make long-term investment and retirement decisions. Therefore, it is critically important to respond to the recommendations in this subsection that are intended to establish the efficient price signals necessary to ensure that the market will facilitate investment in resources over the long term.

2023-6: Implement zonal capacity demand curves and near-term improvements in local clearing requirements

MISO has implemented reliability-based demand curves in MISO's subregions and market-wide. However, it currently has no plans to implement capacity demand curves for the local capacity zones. This raises concerns because the zonal prices that prevail when capacity import or export limits are binding into or out of a zone are likely to be misaligned with reliability.

In particular, Zone 5 in Missouri was short of capacity in 2024–25 PRA during the spring and fall seasons, setting annual prices at 102 percent of the cost of new entry. This price is inefficiently high because the expected unserved energy associated with those zonal shortages remains very low because of the 1-in-100 LOLE criteria applied in the shoulder seasons.

To address this concern, we recommend that MISO begin developing plans to implement locational demand curves in each of its capacity zones that are integrated with the demand curves for the broader areas within MISO. If this cannot be implemented by the 2025–26 PRA, we recommend MISO implement an interim solution to mitigate the potential for inefficient zonal capacity prices. One option is to adjust the zonal demand curves proportionate to the share of the CONE at which the applicable sub-regional demand curve crosses the Planning Reserve Margin Requirement. These improvements will help ensure that zonal capacity prices send efficient economic signals to build and retire resources in each zone.

<u>Status</u>: MISO agrees with the IMM's concerns related to demand curves for local resource zones. MISO plans to evaluate the proposed solution to design and implement sloping demand curves

for local resource zones in the Planning Resource Auction (PRA) after the initial implementation of the Reliability-Based Demand Curve (RBDC) in 2025.

Next Steps: MISO should complete its evaluation of the proposed solution and develop a workplan for implementation.

2022-4: Improve the LRTP processes and benefit evaluations

As MISO moves towards evaluating Tranche 2 of the LRTP, it will be increasingly important to evaluate the costs and benefits of the alternative transmission investments in a process that avoids costly inefficient investments. This is also becoming important for MISO's MTEP process as costs have risen sharply in recent years. This is important because inefficient investment in transmission can undermine incentives that govern other long-term decisions that address congestion at a fraction of the costs of the transmission upgrades. These long-term decisions include generation investment and retirement decisions, investment in energy storage and grid-enhancing technologies, and improved siting decisions by new clean energy resources.

Our evaluation of the LRTP process and results to date raise two primary concerns. First, Future 2A is not realistic because a large share of the future capacity is forecasted by a capacity expansion model that: (i) predicts an excessive amount of intermittent renewable resources will be built and (ii) understates investment in dispatchable and storage resources. Second, we reviewed MISO's benefit analyses and found that some of the nine classes of benefits are not valid and that the aggregate benefits are substantially overstated.

Together, these concerns are troubling because they are prompting costly transmission investment that is uneconomic and designed to address perceived transmission needs that will likely never arise. Therefore, we recommend MISO develop improved methodologies and assumptions to develop its Futures Scenarios and estimating the benefits of the transmission investments.

Status: Throughout 2024 MISO engaged the IMM on these issues. In late 2024, MISO management declared that monitoring the LRTP process is out of the IMM scope. The MISO Board subsequently directed MISO to seek clarification from FERC on this issue in 2025 and to not pay for any work in this area pending the clarification.

Next Steps: The IMM has suspended work on reviewing LRTP and the MISO Futures but is working with MISO to expedite the clarification from FERC.

2022-5: Implement jointly optimized annual offer parameters in the seasonal capacity market

MISO ran the first seasonal PRA in April 2023. The initial implementation included only seasonal offer parameters, which raises substantial challenges for participants that have annual going forward costs they must cover. For example, suppliers with a resource that requires a capital investment to remain in operation would find it difficult to offer such costs because it will not know in how many seasons the resource will clear. MISO is considering giving participants the option of an annual offer in addition to the seasonal offers.

To address this issue, we recommend that MISO implement annual offer parameters that are jointly optimized with the seasonal parameters in the PRA.

Status: MISO agrees with the IMM's observation of the challenges associated with resources' ability to recover annual going forward costs in the market. After multiple discussions with stakeholders, MISO decided to defer development of the new participation model after the initial RBDC filing in 2023. MISO intends to resume the discussion about the new participation model with stakeholders at the RASC in the near future, but no apparent progress was made in 2024.

Next Steps: MISO should work to complete its evaluations in 2025.

2020-4: Develop marginal accreditation methodologies to accredit DERs, LMRs, battery storage, and intermittent resources

Marginal accreditation is essential for aligning the capacity credit granted to a given resource with the reliability the resource provides. This is essential to ensure the market will maintain resources with the attributes needed to meet reliability. The current ELCC methodology applied to wind resources accredits them roughly 15 percent of their nameplate level on average. Unfortunately, this reflects the average reliability contribution of all wind resources, not the marginal reliability value of these resources. This results in excessive accreditation for these resources and so provides poor investment, retirement, and planning incentives.

In 2024, FERC approved MISO's filing to implement a marginal accreditation framework that determines a resources' accreditation based on their expected availability during hours with the highest expected reliability risks, with an implementation date of 2028. Because such risks tend to peak when intermittent output is low, marginal resource accreditation will produce relatively low values for intermittent resources. It will address other types of generation, such as natural gas-only resources in the winter.

Status: MISO's approved marginal accreditation framework does not apply to LMRs and DERs, but MISO filed changes to LMR accreditation in April 2025.

Next Steps: If approved by FERC, implement changes to LMR and Emergency Resource accreditation in the 2028–2029 Planning Year.

2019-5: Remove eligibility of Energy Efficiency to sell capacity

The increasing levels of Energy Efficiency ("EE") capacity credits raise concerns because the claimed savings are based on a wide array of speculative assumptions, and we have found them to be vastly overstated. Hence, EE resources to date have yielded very little real benefits. Further, to the extent that the market payments are used to subsidize consumer purchases of energy efficient products, it is an inefficient subsidy of actions that customers have sufficient incentives to undertake. Retail electricity rates include all the costs of serving the customer, including fixed transmission and distribution costs that do not decrease as consumption falls.

Therefore, consumers' EE savings are generally higher than the value of the reductions to MISO. Additional incentives funded through MISO's capacity market, therefore, are extraneous. Given these concerns, we recommend MISO terminate its rules allowing EE resources to sell capacity because EE resources are demonstrably not comparable to generation or other resources that legitimately provide capacity under Module E.

<u>Status</u>: MISO agrees that Tariff clarifications could be made on EE resources for ownership rights, baseline assumptions, and measurement & verification (M&V) protocols, but these clarifications have yet to be scheduled. Given the recent enforcement action against an EE supplier and FERC approval of a proposal in PJM to eliminate EE from its capacity market, MISO plans to reconsider the participation of EE in MISO.

<u>Next Steps</u>: MISO should work with its stakeholders and the IMM to complete its evaluation and prioritize changes to address this recommendation.

2015-6: Improve the modeling of transmission constraints in the PRA

MISO employs a relatively simple representation of transmission limits in the PRA, modeling only aggregate import and export limits to and from each capacity zone. Additionally, MISO accommodates the transfer limitations between the MISO South and Midwest regions. All other constraints are evaluated through a simultaneous feasibility analysis that may cause MISO to re-run the PRA with modified zonal import or export limits. Ultimately, these issues lead to sub-optimal capacity procurements and sub-optimal locational prices. Hence, we recommend that MISO add transmission constraints to its auction model to address potential simultaneous feasibility issues and to reflect the differing impact of zonal resources on regional constraints.

For relevant internal constraints, MISO should establish shift factors that define how each internal and external zone affects each constraint. Ultimately, this is a very simple version of a constrained optimal dispatch (much simpler than MISO's energy market). It would allow MISO to represent all regional constraints that may be affected by multiple local zones (e.g., the way the three zones in MISO South affect the south-to-north transfer constraint) and to activate any constraints that may arise in its simultaneous feasibility assessment.

Status: Work on this recommendation will be on hold until work on RBDC and accreditation efforts are completed. MISO agrees with the issues identified and has done some preliminary analysis of this recommendation, but further evaluation is required but has not been scheduled.

Next Steps: MISO should evaluate the software and other implications of implementing an efficient locational framework in the PRA. Building on the concepts implemented for the RDT constraint, modeling could be expanded to address additional internal transmission constraints.

2014-6: Define local resource zones based on transmission constraints and local reliability requirements

Currently, a local resource zone cannot be smaller than an entire LBA. In some cases, however, capacity is needed in certain load pockets within an LBA. For example, Narrow Constrained Areas (NCAs) in MISO South have substantial capacity needs to satisfy local reliability requirements. In neither case, however, can the capacity prices in the PRA reflect the need for capacity because of the limited transmission capability into the areas.

This problem was illustrated during Winter Storm Heather when MISO was short of generating resources in the Southeast Texas load pocket. We recommend that MISO adopt procedures for defining capacity zones that would allow the zones to be determined by transmission constraints and other local reliability needs rather than the historical LBA boundaries that are unrelated to the transmission network. This will substantially improve the economic signals provided by the capacity market when generation is needed in these areas.

Status: There was no progress on this recommendation in 2024. Although MISO indicates that it agrees with the recommendation, its current status is inactive. MISO indicates it will evaluate this recommendation further after completing higher priorities such as the RAN.

Next Steps: We continue to encourage MISO to evaluate the benefits of improving the zonal capacity market definitions.

E. Recommendations Addressed by MISO or Retired

In this subsection, we discuss previous recommendations that we now have withdrawn, mainly due to MISO having addressed them since last year.

2023-4: Develop operating procedures for derating transmission constraints and taking other out-of-market actions

To address uncertainty regarding flows over binding transmission constraints, MISO frequently derates them by three to five percent. However, operators sometimes derate constraints 10 to 15 percent or more. These derates generated a marginal cost of $123 million in 2023. As we show in the report, some of these derates were excessive and generated substantial inefficient costs. In evaluating these episodes, we found that MISO has no operating procedures that specify how operators determine the transmission derate levels.

Although transmission derates are likely the most costly action operators take to manage congestion, other out-of-market actions include manual dispatch or “capping” of generating resources. Because these actions override the market’s ability to optimally dispatch and price constraints, they can lead to significant inefficiencies.

To mitigate the inefficient costs that can result from excessive derates and other out-of-market actions, we recommend that MISO develop clear procedures for its operators to follow. Such procedures should identify both the data and information on which operators should rely to adjust the transmission derate levels and take other out-of-market actions. It should also specify clear criteria applicable to this data and information for operators to employ. MISO has improved its operators’ tools and procedures, which should address this recommendation.

2022-2: Improve the real-time wind forecast by adopting enhancements to its current persistence forecasting methodology

MISO’s near-term wind forecast for each resource is used in its real-time dispatch as its Economic Maximum level. Hence, efficient dispatch of the system requires that this near-term forecast be as accurate as possible. Currently, MISO utilizes a “persistence” forecast that assumes wind resources will produce the same amount of output as it most recently observed. The downside of this approach is that the forecasted output will be predictably lower when output has been increasing and will be predictably higher when wind output is dropping. Therefore, we recommend that MISO improve the performance of its real-time market by modifying its persistence forecast.

MISO has continuously made efforts to improve the forecasts. MISO and the IMM aligned on the in-house persistent forecast approach when wind is not dispatched down. In 2024, MISO worked with the IMM and developed the design requirements. Implementation is scheduled with a targeted effective date of first half of 2025.

2021-5: Modify the Tariff to improve rules related to demand participation in energy and capacity markets

In the past few years, we have identified a number of cases where demand response resources or energy efficiency resources were paid substantial amounts for load reductions that were not realized. In early January 2024, FERC acted in one of these cases ordering a disgorgement of $48.5 million and a penalty of $10.5 million.[36] Furthermore, in December FERC issued a penalty order for a participant who fraudulently registered demand response assets in MISO without the

36 Order approving stipulation and consent agreement, FERC Docket IN24-3-000, January 4, 2024.

asset owners' knowledge or consent and an Order to Show Cause for an energy efficiency provider seeking nearly $1 billion in penalties for manipulating MISO's capacity auction.

Some cases have been due to manipulative conduct of the market participants, while some are due to suboptimal Tariff and settlement rules or requirements. Changes in these rules will help address these issues and ensure that MISO customers receive the benefits of the load reductions for which they have paid. This includes changes to baseline and settlement calculations to ensure the estimated load reductions truly represent the additional load that would have existed but for the demand response resource.

We have recommended that MISO work with us to identify and implement improvements to the Tariff, BPMs, and other rules governing these programs. MISO is addressing this recommendation by developing and filing these Tariff improvements. MISO made two filings in early 2025 and plans to make a third in May 2025. These filings address this recommendation.

2019-3: Develop improved capabilities to receive and validate current and forecasted dynamic transmission ratings

For years, we have reported hundreds of millions of unrealized annual savings because MISO's transmission owners do not consistently provide ambient-adjusted and emergency transmission ratings for their facilities. To address these concerns, FERC issued Order 881 requiring MISO and other RTOs to provide such ratings. This Order has also required MISO to make systems enhancements to be able to receive such ratings for all transmission facilities. Although MISO recently filed to extend the deadline to make these improvements, these required changes will ultimately address this recommendation, so we are retiring this recommendation.

2017-7: Accredit emergency resources for the PRA to better reflect their expected availability and deployment performance.

Emergency-only resources, including LMRs and other emergency resources, can sell capacity and are only required to deploy during emergencies when instructed by MISO. If they are not available to mitigate shortages during emergency events, they provide little value. Some emergency resources have long notification times that render them unavailable in an emergency. Operators typically do not declare emergency events more than a few hours in advance because they are often caused by contingencies or unexpected changes in wind output or load.

Hence, emergency resources with long notification times provide little value in most emergencies. This is not a problem for conventional resources with long start times because an emergency need not be declared to commit these resources. Therefore, we have recommended that MISO account for the availability impacts of the emergency designation in its accreditation. MISO has been developing and has filed proposed changes to address this recommendation.

2016-1: Improve shortage pricing by adopting an improved operating reserve demand curve reflecting the expected value of lost load

Efficient shortage pricing is the primary incentive for both dispatch availability and flexibility. As the primary determinant of shortage pricing, the ORDC must accurately reflect the value of reliability. An optimal or "economic" ORDC would reflect the "expected value of lost load", equal to the product of: (a) probability of losing load and (b) the value of lost load (VOLL). Such an ORDC will track the escalating risk of losing load as shortfalls increase.

The shortage prices will send more efficient signals for participants to take actions in response to the shortage and help maintain the reliability of the system. Additionally, as MISO integrates larger quantities of renewables, the ORDC will be pivotal in compensating flexible resources that can start quickly and ramp rapidly to manage the uncertain output of intermittent resources.

Hence, we recommended MISO reform its ORDC by updating its VOLL assumption and determining the slope of the ORDC based on how capacity levels affect the probability of losing load. MISO developed and filed a proposal to address this recommendation in 2024, which was approved by FERC and will be implemented in 2025.

