2023 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
AMP	Automated Mitigation Procedure
ARC	Aggregator of Retail Customers
ARR	Auction Revenue Rights
ASM	Ancillary Services Market
BCA	Broad Constrained Area
BTMG	Behind-The-Meter Generation
CDD	Cooling Degree Day
CONE	Cost of New Entry
CRA	Competitive Retail Area
CROW	Control Room Operating Window
CTS	Coordinated Transaction Scheduling
DA	Day-Ahead
DAMAP	Day-Ahead Margin Assurance Pmt.
DIR	Dispatchable Intermittent Resource
DR	Demand Response
DRR	Demand Response Resource
ECF	Excess Congestion Fund
EDR	Emergency Demand Response
EEA	Emergency Energy Alert
ELMP	Extended LMP
FERC	Federal Energy Reg. Commission
FFE	Firm Flow Entitlement
FRAC	Fwd. Reliability Assessment Commitment
FSR	Fast-Start Resource
FTR	Financial Transmission Right
GSF	Generation Shift Factor
HDD	Heating Degree Day
HHI	Herfindahl-Hirschman Index
ICAP	Installed Capacity
IESO	Ontario Electricity System Operator
IMM	Independent Market Monitor
ISO-NE	ISO New England, Inc.
JOA	Joint Operating Agreement
LAC	Look-Ahead Commitment
LBA	Local Balancing Area
LMP	Locational Marginal Price
LMR	Load-Modifying Resource
LRZ	Local Resource Zone
LSE	Load-Serving Entity
M2M	Market-to-Market
MCC	Marginal Congestion Component
MCP	Market Clearing Price
MISO	Midcontinent Independent Sys. Operator
MMBtu	Million British thermal units
MSC	MISO Market Subcommittee
MVL	Marginal Value Limit
MW	Megawatt
MWh	Megawatt-hour
NCA	Narrow Constrained Area
NERC	North American Electric Reliability Corp.
NSI	Net Scheduled Interchange
NYISO	New York Independent System Operator
ORDC	Operating Reserve Demand Curve
PJM	PJM Interconnection, Inc.
PRA	Planning Resource Auction
PRMR	Planning Reserve Margin Requirement
PVMWP	Price Volatility Make-Whole Payment
RAN	Resource Availability and Need
RDT	Regional Directional Transfer
RPE	Reserve Procurement Enhancement
RSG	Revenue Sufficiency Guarantee
RT	Real-Time
RTO	Regional Transmission Organization
RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Pmt.
SMP	System Marginal Price
SOM	State of the Market
SPP	Southwest Power Pool
SSR	System Support Resource
STLF	Short-Term Load Forecast
STR	Short Term Reserves
TCDC	Transmission Constraint Demand Curve
TLR	Transmission Line Loading Relief
TO	Transmission Owner
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity
UDS	Unit Dispatch System
VLR	Voltage and Local Reliability
VOLL	Value of Lost Load
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 *2023 State of the Market Report* provides an overview of our assessment of the performance of the markets and summarizes our recommendations.

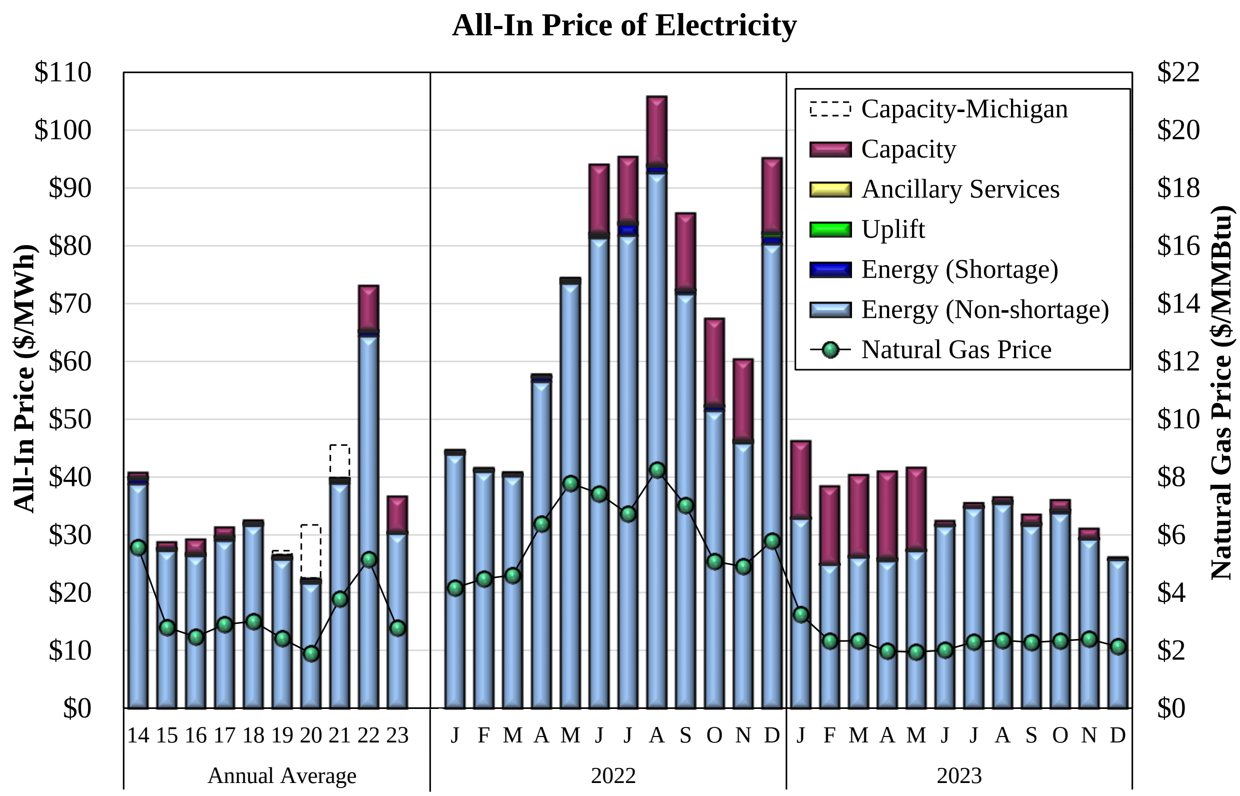
MISO operates competitive wholesale electricity markets in the Midcontinent region that extends geographically from Montana in the west, to Michigan in the east, and to Louisiana in the south. The MISO South subregion shown to the right in blue was integrated in late 2013.

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 2023. Multiple factors affected market outcomes, including lower average load, the continuing change in the resource mix, and falling natural gas prices. The figure below shows a 50 percent reduction in real-time energy prices throughout MISO, which averaged $37 per MWh. Multiple factors contributed to this decrease, including a 46 percent decrease in natural gas prices, the effects of Winter Storm Elliott in late December 2022, and a two percent decrease in average load.



Frequent transmission congestion often caused prices to diverge throughout MISO. The value of real-time congestion fell by half to $1.8 billion in 2023, largely because of lower natural gas prices and lower average wind output compared to 2022. Wind output now contributes to just under half of MISO's real-time congestion. Congestion also resulted in wind curtailments averaging approximately 507 MW per hour and as high as 5.8 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 in defining and coordinating market-to-market constraints;
- More active and 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.

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 three percent, indicating the markets were highly competitive.
- The "output gap" is a measure of potential economic withholding. It remained very low, averaging 0.1 percent of load, which is effectively *de minimus*. Consequently, market power mitigation measures were 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, six of which are new this year. MISO has continued to respond to past recommendations and implemented several key changes in 2023.

Key changes included:

- Transitioning to a seasonal market with availability-based accreditation for conventional resources. The first auction under this new framework ran in the spring of 2023;
- Implementing changes in the reliability commitment process in late 2022 and early 2023 to reduce unnecessary resource commitments and associated RSG; and
- Filing to transition to a reliability-based demand curve in the capacity auction for implementation in the 2025-26 Planning Year.

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. Fortunately, MISO's markets are robust and well-suited to facilitate this transition without fundamental market changes. However, we discuss below some key improvements that will be needed as this transition occurs.

Over the past decade, the penetration of wind 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 example, conventional resources will increasingly have to ramp up quickly in the evenings as the sun sets, particularly in the winter season since load peaks in the evening.
- *Distributed Energy Resources*: MISO is grappling with visibility and uncertainty around these resources. They are generally going to be connected to the distribution system, yet FERC has ordered that DERs be able to participate in all aspects of the RTO markets.[1]
- *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 managed the growth in intermittent resources reliably so far, but we discuss two critical improvements in the following subsections that will be needed:

- Improving shortage pricing to compensate resources that are available and flexible and that allow MISO to maintain reliability when shortages arise; and
- Accrediting capacity resources based on their marginal contribution to reliability, which MISO has proposed in a filing to FERC.

Shortage Pricing in the Energy and Ancillary Services Markets

Virtually all shortages in energy and ancillary markets are of reserve products (i.e., RTOs will hold less reserves rather than not serve the energy demand). When an RTO is short of reserves, the value of the foregone reserves should set the clearing price for reserves and be embedded in all higher-value products, including energy. Efficient shortage prices play a key role in establishing economic signals to guide investment and retirement decisions in the long term, facilitating optimal interchange and generator commitments in the short-run, and efficiently compensating flexible resources. Compensating flexible resources efficiently will be increasingly important as the penetration of renewable resources increases. We expect the frequency of shortages to rise in the future as intermittent output volatility increases.

1 See: 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).

The shortage value is established by the reserve demand curve for each reserve product, so efficient shortage pricing requires a properly valued operating reserve demand curve (ORDC). An efficient ORDC should reflect the marginal reliability value of reserves at each shortage level, which is equal to: *the value of lost load (VOLL) * the probability of losing load*. Unfortunately, neither of these two components is efficiently reflected in MISO's ORDC.

Improving the VOLL. We reviewed the literature and used a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. This study and others estimate VOLLs that vary substantially be customer class. Using the Berkeley Model and MISO data, we estimated a VOLL of close to $35,000 per MWh.[2]

Improving the Slope of the ORDC. The slope of the ORDC is determined by how the probability of losing load changes as the level of operating reserves falls. The probability of losing load depends on the vast combinations of random contingencies and other factors (wind forecast and load forecast errors, and NSI uncertainty) that could occur when MISO is short of reserves. We estimated this probability using a Monte Carlo model that simulates these factors. MISO has also improved its modeling of these factors to develop its proposed ORDC.

MISO's Proposed ORDC. MISO is addressing these recommendations by estimating an updated VOLL and loss of load probability model for calculating an updated ORDC. It proposes to use an effective VOLL of $35,000 per MWh (consistent with our recommendation) to populate the new proposed ORDC shown in Figure 13 in Section III.B. This proposed ORDC will set more efficient prices at different shortage levels and includes a reasonable cap at $6,000 per MWh.

Other Important Market Design Improvements

As MISO's generating fleet transforms, its markets will play an essential role in integrating new resources and maintaining reliability. Improving shortage pricing, the capacity demand curve, and capacity accreditation are the highest priority changes, the latter two of which have been developed and filed with the Commission. However, Section II.B of the report recommends other important improvements to account for the rising system uncertainty and to improve the utilization of the network as transmission flows become more volatile. These are changes that will be key for successfully navigating the transition of MISO's portfolio:

- Introduction of an uncertainty product to reflect MISO's current and future need to commit resources to have sufficient supply available in real time to manage uncertainty;
- Implementation of a look-ahead dispatch and commitment model in the real-time market;
- Introduction of new processes to optimize the operation of the transmission system and improve its utilization; and
- Development of rules and processes for integrating DERs that will satisfy essential reliability and efficiency objectives.

[2] The calculation of these values is described in more detail in Section III.B of the Analytic Appendix.

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 day-ahead prices converge with real-time prices, because this will result in resource commitments that efficiently satisfy the system's real-time operational needs. In 2023:

- The difference between day-ahead and real-time prices, including day-ahead and real-time uplift charges, was roughly three percent. This is good convergence overall.
- 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 increased by 2 and 11 percent in 2023, 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, improving MISO's ORDC is 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. ELMP's effectiveness was initially limited, but MISO has made our recommended changes in recent years, which has improved the performance of ELMP. Section IV.C of this report shows that the average effect of ELMP on MISO's real-time energy prices was $0.74 per MWh in 2023, lower than in prior years because of the lower energy and natural gas prices.

In addition to FSRs, emergency actions and emergency resources can set prices in ELMP during emergencies. In 2021, MISO implemented our recommendations to expand the set of resources that can set prices during an emergency event[3] and increased the default minimum offer floors for emergency resources. These changes significantly improved MISO's emergency pricing.

However, pricing when large quantities of LMRs are deployed is still problematic because the ELMP model cannot ramp other units up quickly enough to replace them. Hence, they can set inefficiently high prices when they are no longer needed. This causes excessive non-firm imports, increased settlement costs, and inflated DAMAP uplift payments to resources that must be held down at overstated prices to make room for the imports and load curtailments. To address this concern, we recommend MISO reintroduce LMR curtailments as an STR demand in the ELMP model instead of energy demand. This will allow the ELMP model to more accurately determine whether they are needed without manipulating the energy dispatch.

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 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. Day-ahead RSG payments fell 62 percent to total $33 million. As usual, the majority of day-ahead VLR costs were accumulated in two load pockets in MISO South.

Real-time RSG. Real-time RSG payments fell 84 percent in 2023. We had identified a number of improvements to MISO's real-time commitment procedures to address concerns that a high percentage of real-time commitments were ultimately not needed to satisfy MISO's reliability needs. MISO created a team to evaluate existing tools and operating practices and has worked with the IMM on these recommendations. Many were implemented in 2023 and account for much of the sharp decline in real-time RSG along with lower fuel prices.

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

3 Resources offering up to a four hour start and minimum run time may now set the price during emergencies.

followed MISO's instructions) averaged over 750 MW and almost 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. This 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. In summary, the proposed penalties will improve dispatch incentives for all resources, but particularly for those whose deviations cause the most serious reliability concerns.

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 2023. Average hourly wind output fell by 8 percent to 10.4 GW per hour compared to 2022 but was still 28 percent higher than three years ago. MISO set a new all-time wind record in early 2024 at more than 26 GW. These trends in wind output are likely to continue for the next few years 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 wind in the day-ahead market, averaging roughly 1,200 MW less than their real-time output. This can be attributed to the suppliers' contracts and the financial risk related to being allocated RSG costs when day-ahead wind output is over scheduled. Under-scheduling can create price convergence and resource commitment issues. These issues are partially addressed by net virtual suppliers that sell energy in the day-ahead market 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, supply and demand imbalances, 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 produce large errors often. We developed a forecast methodology that is also persistence-based but also incorporates the recent direction in output changes. Our analysis of this approach shows that this modest change along with improving the timeliness of the input to the persistence forecast (the most recent observed output) would substantially improve the MISO forecast substantially – reducing the frequency of the highest portfolio-level errors by more than 90 percent. Improving the forecast of wind resources' output will be increasingly important as the penetration of intermittent resources increases. We recommend that MISO implement such changes in forecast methodology.

Transmission Congestion

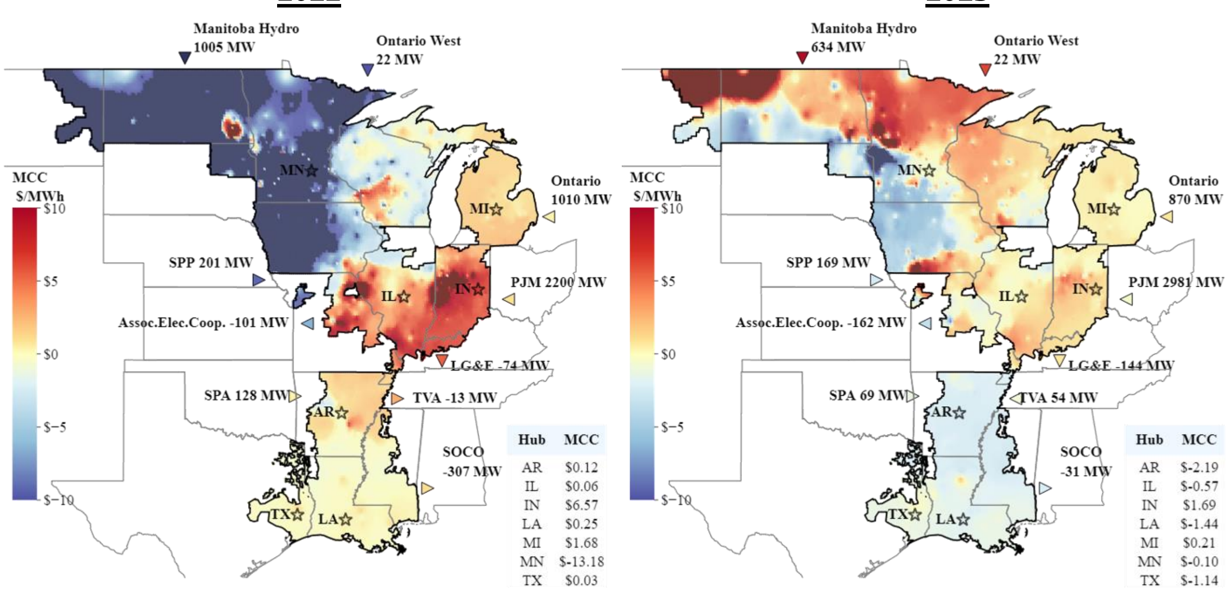
Transmission congestion costs arise on the MISO network when a higher-cost resource is dispatched in place of lower-cost ones to avoid overloading transmission constraints. These congestion costs arise in both the day-ahead and real-time markets. These costs are reflected in MISO's location-specific 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 2022 and 2023.

Congestion Costs in 2023

The value of real-time congestion fell by half in 2023 to $1.8 billion, largely because of the decline in natural gas prices and the decrease in overall wind output. The maps below show the year-over-year changes in congestion patterns from 2022 to 2023.

Average Real-Time Congestion Components in MISO's LMPs

2022 **2023**



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 $1.1 billion in 2023, also roughly half of the 2022 level.

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. If the FTRs issued by MISO are physically feasible (do not imply more flows over the network than the limits in the day-ahead market), then MISO will always collect enough congestion revenue through its day-ahead market to "fully fund" the FTRs—to pay them 100 percent of the FTR entitlement. FTRs were funded at just 97.8 percent in 2023. This underfunding was caused by: a) transmission outages not reflected in the FTR market, b) a substantial constraint that was not modeled properly in the FTR market, and c) an SPP constraint coordinated under the market-to-market processes, which is the cause of a complaint filed by MISO. These issues are discussed in Section V.B of the report.

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 $519 million in real-time congestion costs in 2023 – 30 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 $270 million in congestion costs in 2023 by using temperature-adjusted and emergency ratings. In late 2020, FERC issued a proposed rule that would make this a requirement. We urge MISO to work with the TOs to provide such improved ratings in a timelier manner than required by the FERC rule.

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.

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 $733 million in 2023, which was more than 30 percent of all congestion in MISO. Because there are so many MISO constraints that are affected by generators in SPP and PJM, it is increasingly important that M2M coordination operate as effectively as possible.

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), which is responsible for managing the constraint. Our analysis of M2M coordination provided the following findings:

- M2M coordination has generally contributed to shadow price convergence over time and lowered costs of managing congestion. However, we also find that coordination could be improved with three key changes and deliver substantial additional savings.
- *Relief request software*. Improving the software used to determine the amount of relief requested by the MRTO 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 or can cause a constraint to oscillate from binding to unbinding. Based on our analysis of this issue with SPP, we believe improving the relief requests would generate over $60 million in annual savings.
- *Five-percent test*. Constraints are identified as M2M constraints if the NMRTO has substantial market flows on the constraint or has a single generator with a GSF greater than five percent on the constraint. The five percent test has frequently resulted in constraints designated as M2M constraints for which the benefits of coordinating are extremely small. Hence, we recommend that MISO replace the current five-percent test with a test based on the NMRTO's relief capability on the constraint.
- *Automation of the M2M Processe*s. MISO has made progress in improving the M2M processes over the years, particularly in the area of testing new constraints in a timely manner. Given that much of this process continues to be implemented manually, there are still significant opportunities to improve the timeliness with which constraints are tested and activated by expanding the automation of the M2M processes.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

The capacity surplus MISO had enjoyed prior to the 2023–24 Planning Year dwindled in recent years as the retirements of baseload resources have mostly been replaced with intermittent renewable resources. In 2023, 2.8 GW of resources retired or suspended operations in MISO, comprised mostly of coal and gas steam resources. 5 GW of new unforced capacity entered MISO, including:

- A 1 GW natural gas-fired combined-cycle in the Midwest region and a 600 MW natural gas-fired combined-cycle in the South region;
- Approximately 2.6 GW (UCAP) of solar resources were added in 2023, roughly split between the Midwest and South, more than doubling MISO's solar capacity; and
- Roughly 700 MW of new wind resources, providing 240 MW of unforced capacity.

MISO was not short of capacity in the 2023–24 PRA as its load forecast and requirements fell and some new capacity resources entered. Nonetheless, we expect the retirement trends above to continue and for MISO to continue to struggle to maintain adequate resources if it does not improve the price formation in its capacity market. These price formation issues discussed above substantially affect the net revenues available to new and existing resources in MISO, which is discussed in the next subsection.

Long-Term Signals: Net Revenues

Market prices should provide 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 2023.

We find net revenues fell in all regions in 2023 because lower natural gas prices contributed to lower energy and ancillary services prices throughout MISO. In addition, MISO did not experience any extreme weather events similar to Winter Storm Elliott in December 2022. In all areas in MISO, net revenues were well short of those needed to support investment in new resources. This is largely a result of the market design issues described discussed below.

PRA Market Design

MISO has implemented two significant changes in its capacity market to more effectively and efficiently satisfy its resource adequacy requirements – (i) a seasonal capacity market; and (2) an availability-based accreditation for thermal resources. We provided extensive feedback and analyses to MISO in the implementation of these changes. The first PRA with these changes occurred in early May 2023. However, these changes did not address underlying concerns with the representation of demand in the auction, which causes prices to be understated. However, MISO filed proposed reliability-based demand curves in September 2023, which is planned to be implemented beginning in the 2025-26 Planning Year. This change, recommended for more than a decade, will address the most substantial design flaw in the capacity market and will greatly improve the economic signals governing resource investment and retirement decisions.

The second most important improvement to MISO's capacity market is changing its framework to accredit resources based on their marginal value in reducing potential load shedding events. MISO worked in 2023 to develop a proposal to address this recommendation and filed it in early 2024. We have also recommended several other improvements to the PRA. A number of these changes involve improving the accuracy of the supply and demand in the PRA, including:

- Improving the accreditation rules for emergency-only resources in the PRA; 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 with MISO along with the high-priority changes to the capacity demand curve and accreditation methodologies will allow the PRA to provide efficient economic signals. These signals will help ensure that the MISO region remains reliable as its generation fleet transitions.

Long Range Transmission Planning

In July 2022, the MISO Board approved $10.3 billion of Long Range Transmission Plan (LRTP) projects. The LRTP Tranche 1 evaluation focused on the most clearly beneficial projects. In 2023, MISO has been working on Tranche 2 of the LRTP to address transmission issues over the next 20 years in the Midwest associated with its forecasted "Future 2A." This Tranche could contain as much as $30 billion in additional transmission investment, so it will be increasingly important to accurately evaluate the costs and benefits of the transmission investments to avoid costly, inefficient investments. This is critical because inefficient investment in transmission can undermine incentives that govern other long-term decisions, such as generation investment and siting decisions, retirement decisions, and investment in energy storage. Some of these decisions can address congestion issues at a fraction of the costs of the transmission upgrades.

In evaluating the development and evaluation of Tranche 2, we have discussed significant concerns with MISO and its participants:

- *Future 2A is not realistic.* This is a concern because it is the basis for MISO identifying Tranche 2 projects and evaluating their benefits. It is unrealistic 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 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 has indicated that it will be estimating 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 would direct investment to constrained areas, which mitigates the congestion and lowers many of the classes of benefits. We identify that three classes of benefits should be deleted or substantially modified because the benefits are already captured in other classes (e.g., decarbonization) or because the benefits are likely to be close to zero if properly calculated (e.g., Avoided Capacity Costs and Mitigation of Reliability Issues).
- *Benefits should be calculated for groups of projects*. It will be essential to calculate the benefits for individual groupings of investments in Tranche 2 to ensure that only those investments that qualify as "no regrets" investments are billed to MISO's customers, while investments that have little or no value in a more realistic scenario are removed from the portfolio.

We recommend that MISO make changes to address these factors in its analyses of the Tranche 2 projects and the future Tranche 3 and 4 projects. This will help ensure that the transmission upgrades are economic and do not undermine the MISO markets.

External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2023, importing an average of 4.5 GW per hour in real time over all interfaces and 3.1 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. To calculate an accurate congestion price at the interface, an RTO must assume the sources or sinks in the neighboring area (referred to as the "interface definition"). Ideally, RTOs would assume sources and sinks throughout each RTO's footprint since this is what happens in reality. Unfortunately, MISO adopted a "common interface" definition for the PJM interface consisting of ten generator locations near the PJM seam. This has increased interface price volatility, resulted in less efficient imports and exports, and raised costs for customers in both regions. Hence, we encourage MISO to consider revising its interface pricing with PJM to match our recommended pricing for the SPP interface.

At the SPP interface, MISO and SPP both price congestion on M2M constraints they are coordinating. This duplicative pricing inflates the incentives associated with this congestion to schedule imports and exports. We encourage MISO to adopt an efficient interface pricing method at the SPP interface and its other interfaces by removing all external constraints from its interface prices (i.e., pricing only MISO constraints). If SPP does the same, the redundant congestion issue will be eliminated, and the interface prices will be efficient.

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. The participation in CTS has been minimal because of high transmission charges and persistent forecast errors 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 most recent five-minute prices in the neighboring RTO area.

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 2023 of the CTS process with PJM from actual savings of $7.2 million under the current approach to more than $100 million under the five-minute adjustment approach. We estimate savings of $34 million for a similar approach with SPP.

Demand Response and Energy Efficiency

Demand response is an important contributor to MISO's resource adequacy. MISO had 12.7 GW of DR resources in 2023, 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 recommend MISO make further accreditation improvements for 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[4]; and

4 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.

- 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 investigated and referred to FERC for market manipulation ceased participating. This caused payments to DRRs to fall to just $3.2 million in 2023. Our investigation 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 recommend 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.

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.

To evaluate the accuracy of the claimed savings, the IMM performed an audit of EE capacity that had been sold in the PRA in prior years. Based on this audit, we 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.

These findings are unfortunate because MISO’s customers paid more than $17 million to these resources in a prior PRA and received virtually nothing in return. Since MISO’s EE program is not addressing a known inefficiency and the quantities are difficult to accurately estimate or verify, we have recommended that MISO disqualify EE from selling capacity. Alternatively, MISO should make Tariff changes to ensure that any payments to EE resources are justified.

Table of Recommendations

Although the markets performed well in 2023, we make 31 recommendations to further improve their performance. Six are new, while 23 were recommended previously. MISO addressed three 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.

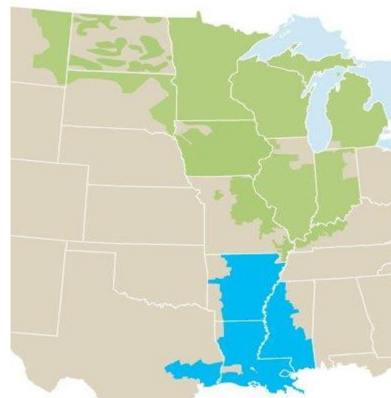
SOM Number	Recommendations	High Benefit	Near Term
Energy and Operating Reserves and Guarantee Payments			
2023-1	Align aggregate pricing nodes in the FTR market through real-time.		✓
2023-2	Enforce STR requirements in the load pockets.		
2021-2	Evaluate reintroducing LMR curtailments as STR demand in pricing models and UDS.		
2021-5	Modify the Tariff to improve rules related to demand participation in energy markets.		✓
2020-1	Develop a real-time capacity product for uncertainty.	✓	
2016-1	Improve shortage pricing by adopting an operating reserve demand curve reflecting the expected value of lost load.	✓	✓
2012-3	Remove external congestion from interface prices.		✓
2012-5	Introduce a virtual spread product.		
Transmission Congestion			
2023-3	Develop tools to recommend decommitment of resources committed in the day-ahead market.	✓	
2023-4	Develop operating procedures for derating transmission constraints and taking other out-of-market actions.		✓
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.		
2019-3	Develop improved capabilities to receive and validate current and forecasted transmission ratings.	✓	
2016-3	Enhance authority to coordinate transmission and generation planned outages.		

SOM Number	Recommendations	High Benefit	Near Term
2014-3	Seek joint operating agreements with neighboring control areas to improve congestion management and emergency coordination.		
Market and System Operations			
2023-5	Require descriptions in new or updated CROW tickets.		
2022-2	Improve the real-time wind forecast by adopting enhancement to its current persistence forecasting methodology.	✓	✓
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.		✓
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.		✓
2017-7	Accredit emergency resources for the PRA to better reflect their expected availability and deployment performance.		
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 – that facilitates the sale and trading of FTRs that grant the holders an entitlement to day-ahead congestion revenues, allowing them to speculate on or hedge congestion.

Capacity Market – that is implemented through the Planning Resource Auction (PRA) to compensate resources for meeting the resource adequacy needs of the system.

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 2023. Key improvements included:

- Capacity Market: Transitioning to a seasonal market and availability-based accreditation in spring 2023 and filing to implement a Reliability-Based Demand Curve in 2025.
- Market Operations: MISO made some key changes in its commitment practices and settlement rules to reduce unnecessary commitments and inefficient uplift payments.

These changes should improve the performance of the markets and the operation of the system. We discuss other changes in this report to improve MISO's market design and operation that are necessary to position MISO to successfully navigate the transition of its generating fleet. These recommendations are discussed in Section X of the report that includes the current status of each recommendation and a description of those MISO addressed in 2023.

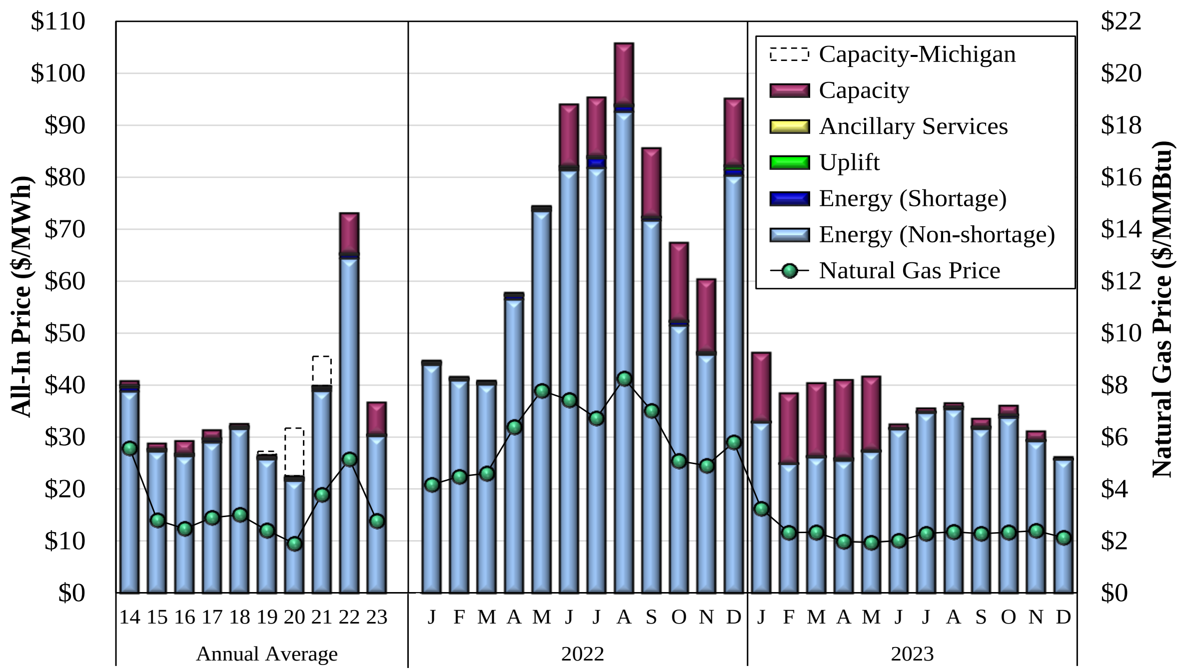
II. Price and Load Trends

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 2023

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.[5] 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 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
2022–2023



The all-in price fell 50 percent in 2023 to an average of $37 per MWh.

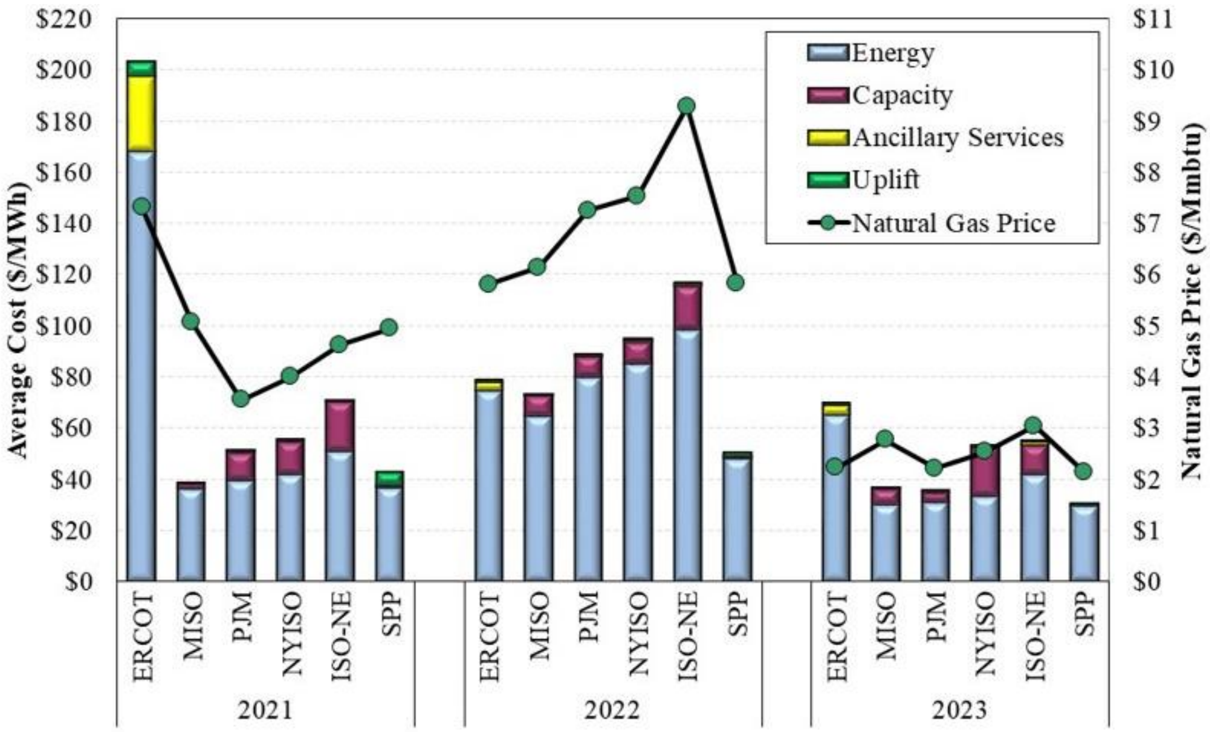
- Energy prices fell 53 percent as natural gas prices decreased 46 percent. Coal supply issues that contributed to higher prices throughout 2022 were resolved in 2023.

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

- Shortage pricing fell 73 percent from 2022 when MISO experienced sustained periods of shortage pricing during Winter Storm Elliott.
- The ancillary services component contributed only $0.09 per MWh.
- The capacity component of the all-in price fell 20 percent from 2022 because the Midwest region cleared at CONE in the 2022–23 capacity auction, and capacity clearing prices returned to inefficiently low levels in the 2023–24 auction.
- The uplift component of the all-in price fell 81 percent to $0.04 per MWh because of improvements in MISO's commitment practices and lower gas prices in 2023.[6]

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
2021–2023

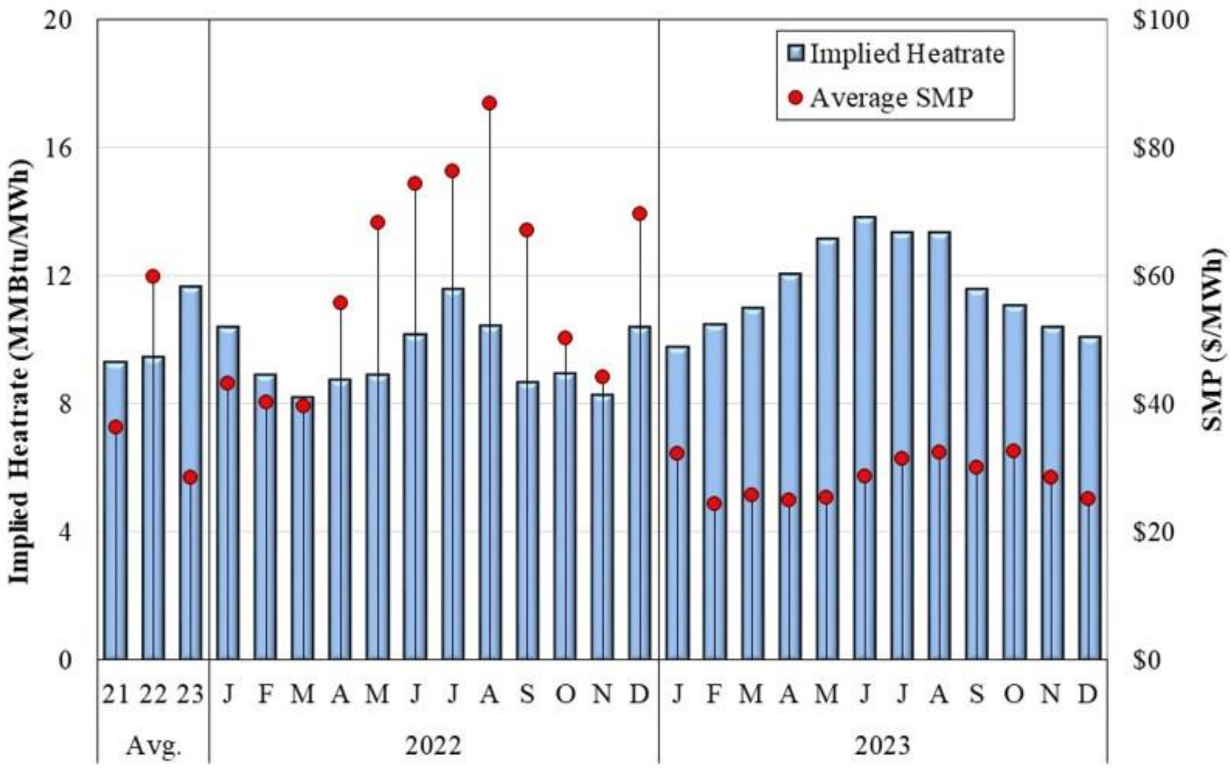


Each of these RTO markets have converged to similar market designs, including nodal energy markets, operating reserves and regulation markets, and capacity markets (with the exception of ERCOT and SPP). However, the details of the market rules can vary substantially. The market prices and costs in different 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.

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

In Figure 2, MISO exhibits among the lowest all-in prices because of its low natural gas prices and weak shortage pricing. ERCOT lacks a capacity market entirely but has much stronger shortage pricing. ISO New England's higher capacity prices were largely due to load being over-forecasted in its 3-year ahead forward capacity market. Its relatively high energy prices are caused by higher gas prices that reflect pipeline constraints. To estimate the effects on prices of factors other than fuel prices, 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.[7]

Figure 3: Implied Marginal Heat Rate
2022–2023



While the nominal SMP in 2023 decreased by 53 percent relative to 2022 because of lower gas prices, the implied marginal heat rate increased 23 percent from 2022 to 2023 because of a shift in the marginal resources to serve load. Most of the other differences in system marginal prices were 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 2023. MISO lost 2.8 GW of Unforced Capacity (UCAP) from retirements and suspensions and added nearly 5 GW of new resources. These

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

included a 1 GW natural gas-fired combined-cycle resource that entered the Midwest, a new 600 MW combined-cycle resource in the South, and over 2.4 GW of new solar. While approximately 700 MW of new installed wind capacity entered MISO in 2023, this only constitutes a few hundred MW of new Unforced Capacity. The remaining increase in unforced wind capacity was from existing resources procuring more firm transmission to be deliverable in the 2023–24 PRA.

Table 1 below summarizes the share of capacity (in UCAP), energy output, and how frequently different types of resources were marginal in setting system-wide energy prices and locational energy prices in 2022 and 2023.

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

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2022	2023	2022	2023	2022	2023	2022	2023	2022	2023
Nuclear	10,905	10,823	9%	8%	15%	14%	0%	0%	0%	0%
Coal	40,242	38,595	32%	30%	34%	28%	24%	36%	63%	79%
Natural Gas	60,600	62,317	48%	48%	33%	39%	75%	63%	90%	94%
Oil	1,448	1,469	1%	1%	0%	0%	0%	0%	0%	1%
Hydro	3,979	4,221	3%	3%	1%	1%	1%	1%	2%	2%
Wind	4,698	4,948	4%	4%	16%	15%	0%	0%	68%	59%
Solar	1,958	4,394	2%	3%	0%	0%	0%	0%	3%	8%
Other	2,855	2,679	2%	2%	2%	2%	0%	0%	5%	1%
Total	**126,685**	**129,447**								

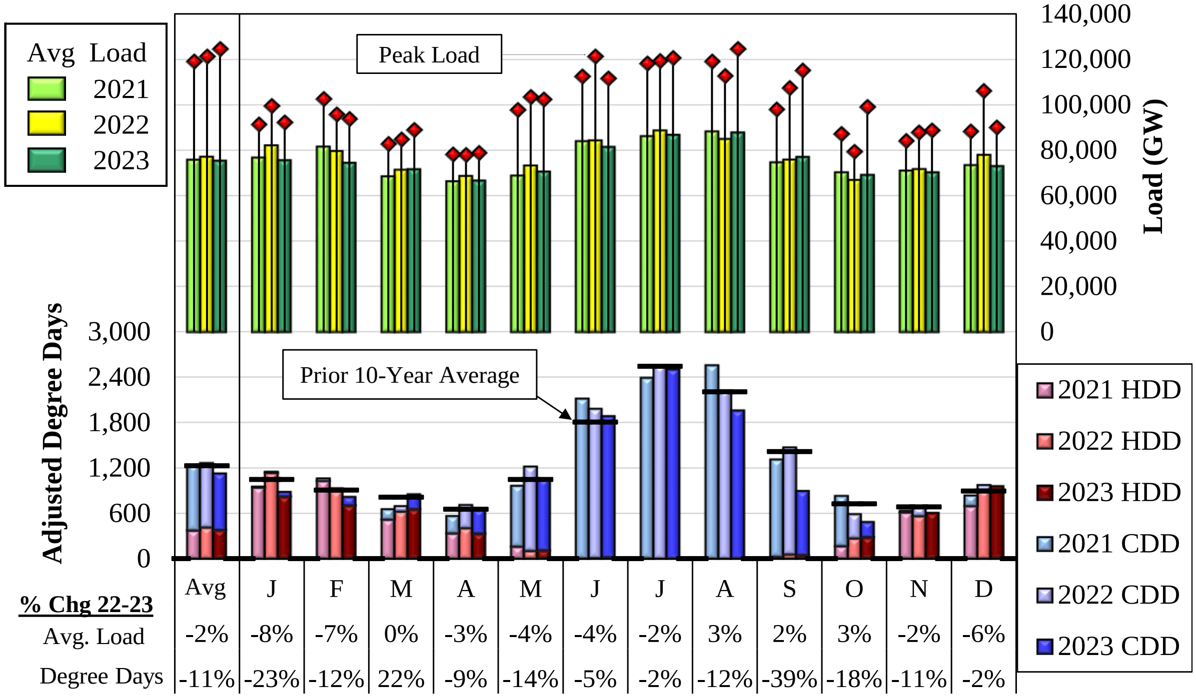
Energy Output Shares. The lowest marginal cost resources (coal and nuclear) became less profitable -- as energy prices fell, their share of energy output fell accordingly. This caused the share of energy produced by natural gas resources to rise as the lower gas prices led them to be more economic. Although wind capacity continued to grow, its share of energy output decreased slightly to 15 percent in 2023 because of lower output on average, which was likely due to the impacts of an El Nino climate pattern that developed in the middle of the year. The nuclear share of output fell slightly as an 800 MW nuclear unit retired in May 2022, although this resource has announced it will return to service by the end of 2025.

Price-Setting. Coal resources set system-wide prices in 36 percent of hours, up from 24 percent in 2022. 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, down from 75 percent, and including almost all peak hours. In addition, congestion often causes gas-fired units to set prices in local areas (94 percent of intervals) when lower-cost units are setting the system-wide price. Wind units set prices in 59 percent of all intervals, which is lower than the 68 percent of intervals last year because average wind production was down year over year.

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.[8]

Figure 4: Heating and Cooling Degree Days
2021–2023



In 2023, the system average load fell two percent and the number of degree days fell 11 percent from 2022. Some notable weather trends occurred throughout 2023, including:

- Relatively mild temperatures in January and February throughout MISO resulted in lower heating degree days and lower average load early in the year.
- During the spring season, mild weather contributed to a two percent decrease in average load compared to the prior year.
- Most regions experienced extremely hot temperatures in late July and August. The South was the hottest since integration and set multiple record peak loads during those months.
- Parts of the Midwest experienced almost record high temperatures in September – leading to a seven percent higher fall quarterly peak load than the prior year.

MISO's annual peak load of 126 GW occurred on August 23, as hotter than normal footprint-wide temperatures led to high peak cooling demand. The annual peak load was 2.1 percent higher than the 50/50 forecasted peak of 123 GW from MISO's *2023 Summer Seasonal*

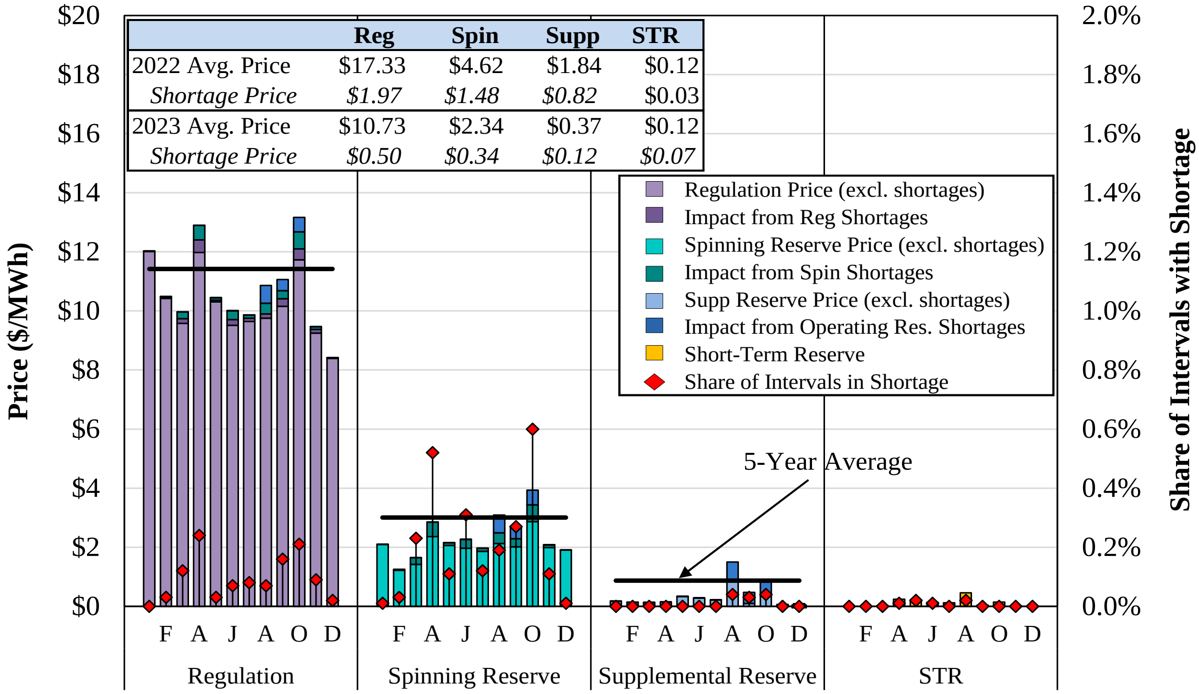
8 HDDs and CDDs are defined using aggregate daily temperatures relative to a base temperature (65ºF). To normalize the load impacts of HDDs and CDDs, we inflate CDDs by 6.07 (based on a regression analysis).

Assessment. In the week leading up to August 24, MISO was forecasting peak annual load in excess of 130 GW based on extremely high forecasted temperatures. We discuss this hot weather period and the operational challenges that occurred in detail in subsection E below.

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 since it was implemented in late 2021.

Figure 5: Real-Time ASM Prices and Shortage Frequency
2023



	Reg	Spin	Supp	STR
2022 Avg. Price	$17.33	$4.62	$1.84	$0.12
Shortage Price	*$1.97*	*$1.48*	*$0.82*	*$0.03*
2023 Avg. Price	$10.73	$2.34	$0.37	$0.12
Shortage Price	*$0.50*	*$0.34*	*$0.12*	*$0.07*

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.[9] Likewise, energy prices

[9] The demand curve for regulation, which is indexed to natural gas prices, averaged $110.28 per MWh in 2023, down from $289.41 per MWh in 2022. 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%).

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 of higher-valued reserves and energy through the co-optimized market clearing.

Figure 5 shows that the average clearing prices fell for all reserve products in 2023 (but flat for STR), primarily because of changes in natural gas prices. Lower opportunity costs caused by lower natural gas prices contributed to the 49 percent decrease in spinning reserve prices.

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 2023.

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 STR demand curve to a multi-step curve that reaches a high step of $500 per MWh (previously set at $100 per MWh) to price STR shortages efficiently.

While this change has improved the performance of STR, we also recommend MISO expand the RPE constraints to enforce STR requirements in local reserve zones that have VLR requirements. Enforcing local STR requirements will provide efficient incentives for suppliers to invest in fast-start units that can satisfy the VLR requirements and should reduce the need to commit expensive units in those areas out of the market.

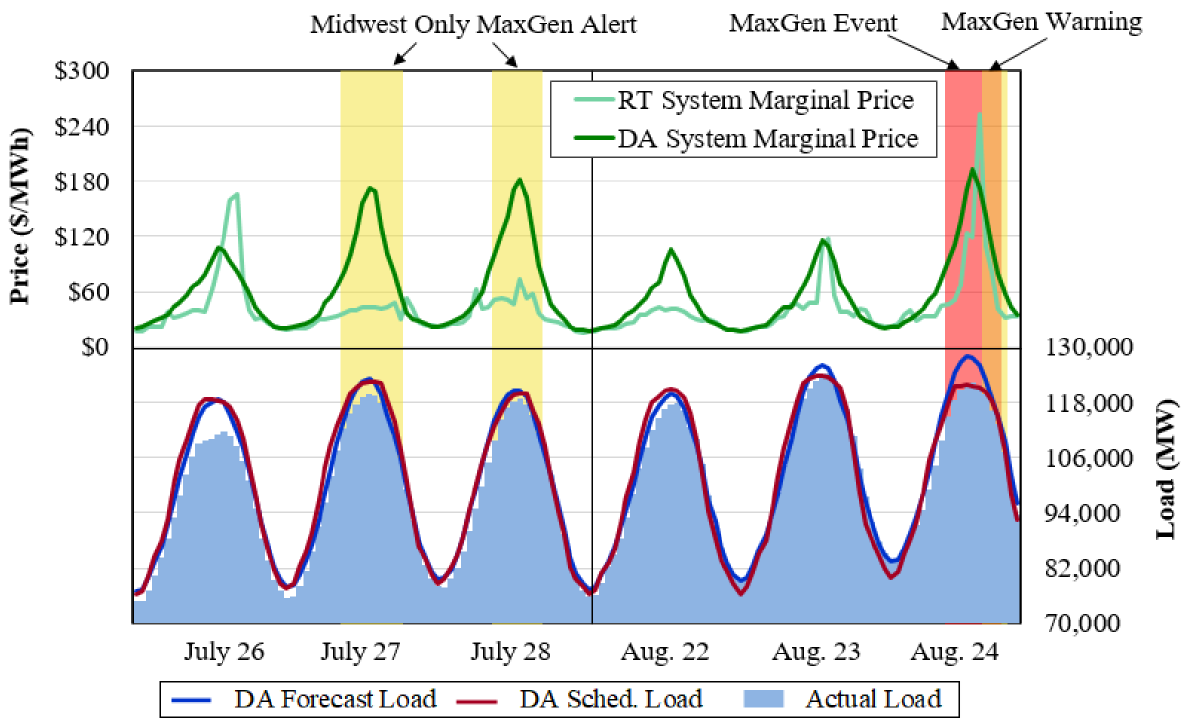
E. Hot Summer Conditions and Market Outcomes

During the summer, MISO experienced extended periods of hot weather that led to multiple Hot Weather Alerts and Conservative Operations declarations. On several of the hottest days, MISO substantially over-forecasted the load. Figure 6 illustrates six peak days in late July and late August when MISO over-forecasted by 2 to 8 GW. Some of the load forecasting errors may have been due to self-scheduled load-modifying resources (LMRs). We typically see more than 1 GW of self-scheduled behind the meter generation across the peak hours and over 1 additional GW of load curtailments on the tightest days. Behind the meter solar may be contributing to errors as well. Improving the forecasting of super-peak summer conditions should be a priority.

In late July, high forecasted temperatures and load in the Midwest led to an early Maximum Generation Alert declaration for July 27th. The two-day advance Alert likely informed some of the participants' preparations. Almost all resources online that day were scheduled in the day-ahead market so real-time commitments and associated RSG were low (less than $50,000).

However, peak load during this three-day event was significantly over-forecasted. The net load in the day-ahead market was comparably over-scheduled, indicating that participants also likely over-forecasted load. This over-forecast led day-ahead prices to exceed real-time prices in most peak hours, and by more than $130 per MWh during the peak hour on July 27.

Figure 6: Hot Summer Conditions and MISO Emergency Declarations



Maximum Generation Event on August 24th

Emergency procedures allow MISO to access supply and demand that increases its reserve margin (supply – energy and operating reserve demand). Since emergency declarations increase the available margin outside of the market, they tend to distort market outcomes and should only be invoked when necessary. Emergency declarations provide the following pricing and capacity effects to address the needs of the system:

- Alert: allows 4-hour online resources to set price in ELMP
- Warning: Tier 1 emergency pricing in ELMP, curtail non-firm exports, call external capacity resources to import
- Step 1: a) can commit emergency only units, b) activate emergency output ranges in the real-time dispatch (instantly available)
- Step 2: a) Tier 2 pricing and LMRs available, b) emergency DR, c) emergency energy purchases from neighbors
- Steps 3-5: Raise priority of transaction curtailments, call reserves from reserve sharing group, shed firm load.

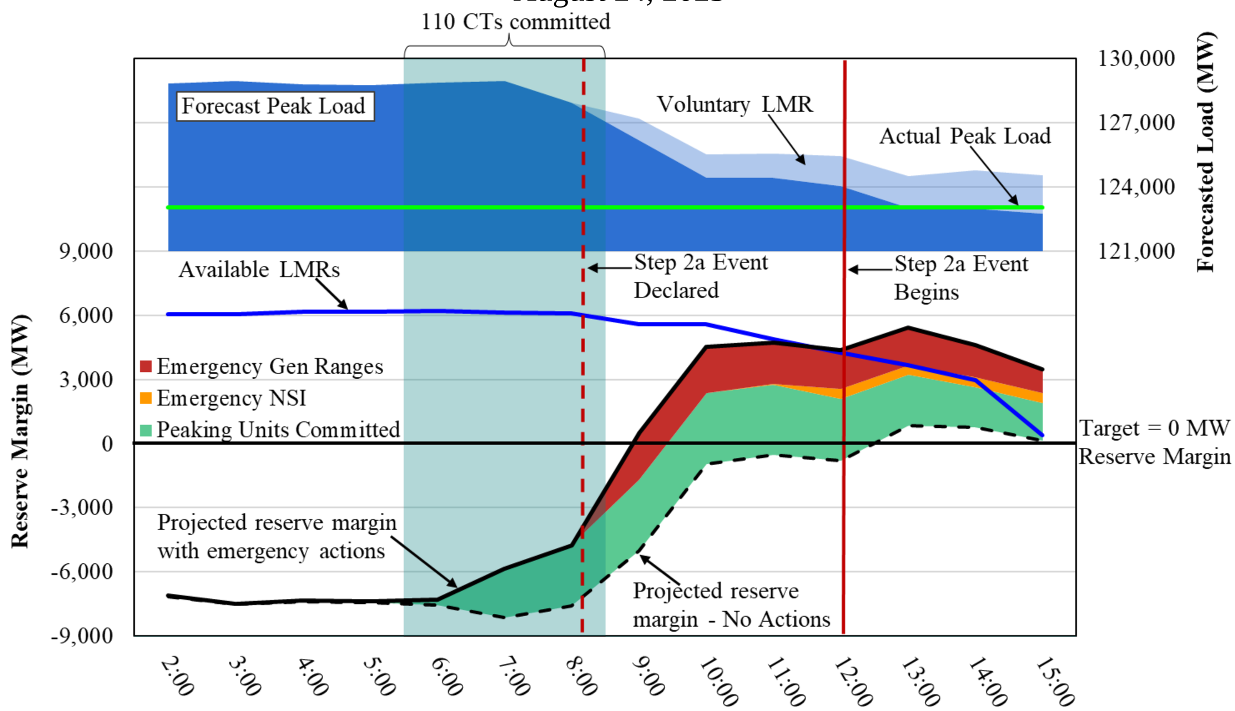
With the exception of the Alert, each of these emergency levels increases the supply-demand margin by increasing supply or decreasing demand. Because these changes will substantially affect market prices, MISO should only declare each level of declaration when the additional MWs available in that level of emergency will be needed to avoid an operating reserve shortage. Short Term Reserves provide for uncertainty, and MISO can increase the STR requirements to manage uncertainty during periods of forecasted tight conditions.

In the week leading up to August 24, MISO forecasted an annual peak load above 130 GW because of extremely hot forecasts in many of its load centers. In preparation, MISO:

- Increased the STR requirements by 900 MW from August 21 through August 25 to hold 2000 MW above its operating reserve requirements in the peak hours; and
- Issued a Maximum Generation Alert two days in advance to allow participants to prepare.

Early on August 24, 2023, MISO forecasted a sizable deficit in the peak hour, as shown in Figure 7 below. In the figure, we illustrate the impact of MISO's actions on the forecasted reserve margin for the peak hour that day.

Figure 7: Peak Hour Projected Reserve Margin
August 24, 2023



Because of the sizable forecasted deficits, MISO started taking actions early in the day:

- Sending commitment instructions to fast-starting turbines at 6 am, which is represented by the green shading under the projected reserve margin with emergency actions line.
- At 8am, MISO declared a Step 2A Event to begin at noon – providing access to LMRs – but the LMRs were not needed, and MISO ultimately did not call on them.

- After the event declaration, 1300 MW of self-scheduled LMRs curtailed voluntarily, which improved the forecasted reserve margin by reducing the peak load.

The timing of MISO's actions early in the day was not ideal because most of the turbines, LMRs and emergency capacity would still have been available 5 to 6 hours later. By 10 a.m., 2 hours before the start of the event, the forecasted load fell and led to a large forecasted surplus and positive reserve margin. At that point, downgrading or retracting the event would have been ideal. The surplus supply resulted in understated prices, although this was mitigated by ELMP.

However, MISO made some very good decisions before and during the event, including:

- Decommitting 60 peaking units, 1800 MW of the 3300 MW it committed, which saved $1.6 million in RSG costs.
- Increasing the STR requirements to reflect the increased needs and uncertainty; and
- Not calling for the LMRs to curtail before it determined they were needed.
- Informing members in advance of the projected emergency to ensure that resources could prepare for anticipated conditions and manage their own risk.

IMM Conclusions and Recommendations for Future Hot Weather Emergencies

The August 24 Maximum Generation Event indicates opportunities to improve and clarify the emergency procedures:

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 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 sharply 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 would allow 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.

III. FUTURE MARKET NEEDS

The MISO system is changing rapidly as the generating fleet transitions and new technologies enter the market, which will require MISO to adapt to new operational and planning needs. MISO has been grappling with these issues in several initiatives, including the Renewable Integration Impact Assessment (RIIA), the Regional Resource Assessment (RRA), and in the *MISO Futures Report*, *MISO Response to the Reliability Imperative,* and *Attributes Roadmap.*

MISO's markets are well-suited to facilitate this transition and fundamental market changes will not be needed. However, a number of key improvements will be critical as MISO proceeds through this transition, some of which are currently underway. We discuss the key issues in this section that MISO will be facing in the coming decades and recommend both principles and specific market improvements MISO should consider as it moves forward.

We begin the chapter with a discussion of the remarkable changes anticipated in MISO's generation portfolio and the implications of these changes. We then identify the key market and non-market improvements that will allow MISO to successfully navigate this transition.

A. MISO's Future Supply Portfolio

In recent years, the penetration of wind and solar resources in the MISO system has consistently increased as baseload coal resources have retired. To date, MISO has effectively managed the operational challenges of integrating intermittent resources while losing conventional dispatchable resources, although this trend is expected to accelerate as large quantities of solar and battery storage resources join new wind resources in the interconnection queue. MISO has more than 1200 active projects in the interconnection queue, totaling over 225 GW. Half of these are solar projects, and an additional 19 percent are hybrid projects, while 15 percent are battery storage, and another 10 percent are wind projects. Distributed energy resources may also grow and play a more substantial role in the future. However, 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.

Changes are also anticipated on the demand side. MISO has evaluated significant electrification of the transportation sector with the widespread adoption of electric vehicles (EVs). Such a transition may substantially change typical load profiles and congestion patterns. Nonetheless, the most significant changes are likely the supply-side changes discussed above.

Figure 8 shows the anticipated mix of resources based on MISO's prior and updated "Future 2" Scenarios that are used for its planning studies (Future 2 and 2A). The Future 2 scenarios are an intermediate scenario between Future 1 that shows a slower clean energy transition and Future 3 that shows a faster transition and substantial assumed electrification of both the transportation sector (primarily EVs) and residential heating/cooling (advanced heat pumps).[10] Figure 8 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 8: Anticipated Resource Mix: 2032 and 2042

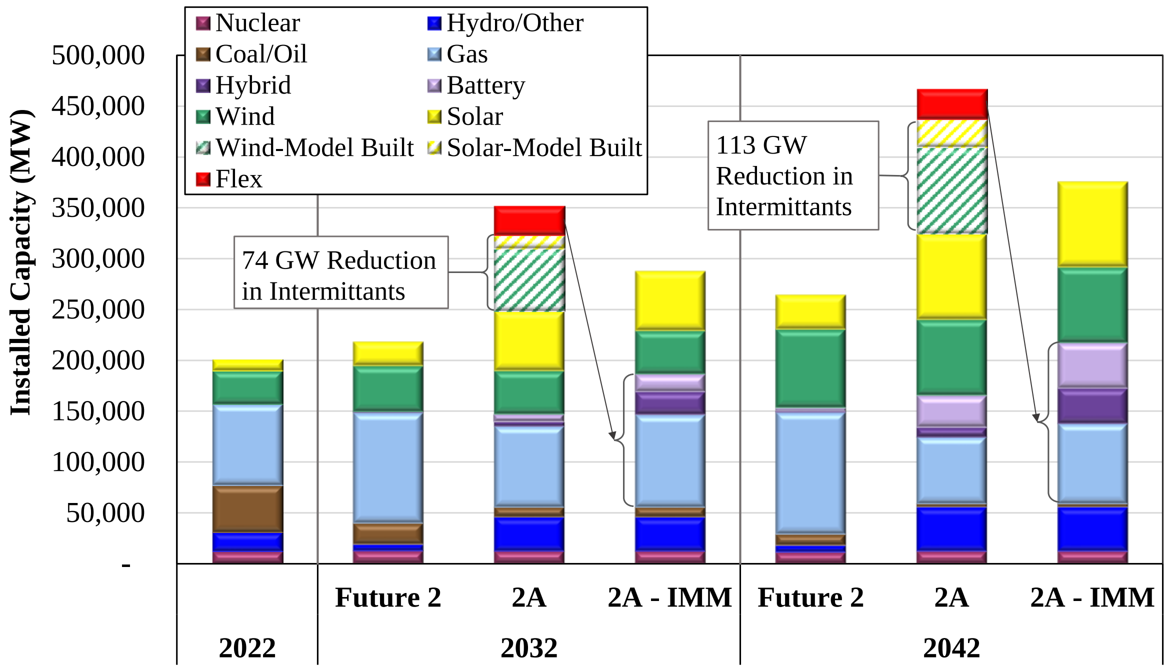


Figure 8 shows that MISO's expectations have changed substantially over the past two years since Future 2 was published. Unfortunately, we find that Future 2A is an unrealistic case that is not suitable as a basis for MISO planning. Hence, we developed an alternative case to address some of our largest concerns. A review of Future 2A shows:

- A roughly 50 percent reduction in coal in 2032 and 2042 compared to Future 2, some of which is due to a more aggressive age-based retirement assumption (36 years). This is questionable for resources in states with no announced decarbonization plans.
- Reductions in gas-fired generation of 34 and 48 percent compared to the Future 2 levels in 2032 and 2042, respectively – this is unrealistic given the system's need for the attributes that these resources provide. In fact, a number of regulated utilities have announced billions of dollars of investment in new gas generation over the past year.
- Much faster growth of intermittent solar and wind resources – 154 percent in 2032 and 143 percent in 2042 than in Future 2. This is driven by two factors:
  (1) Announced plans of states and utilities, and
  (2) Projections by the Electric Generation Expansion Analysis System (EGEAS) model to build new resources to satisfy MISO's needs.

10 MISO Futures Report, Series 1A.

We find that the intermittent resources projected by the EGEAS model, almost 113 GW in 2042, greatly overestimates the expansion of intermittent resources because:

- The EGEAS model assumes investment in resources that *minimize costs*, ignoring revenues. In the real world, suppliers maximize *profits*—revenues minus costs. Therefore, the EGEAS model ignores the increasing energy and capacity market revenue available to dispatchable resources.
- MISO chose to include renewable subsidies from the Inflation Reduction Act as *cost reductions* rather than more appropriately as revenues.
- MISO assumes unrealistically high capacity accreditation levels for intermittent resources in the EGEAS model.[11] These levels are much higher than their marginal reliability value, particularly after 2032 when large quantities of both types of resources are assumed to have been built.

These three issues cause the EGEAS model to generally always select intermittent resources when new resources are needed in the future. If the model reflected that their contribution to reliability will be close to zero by 2032 and that units with needed attributes would receive disproportionately large market revenues, it would select other types of resources to satisfy MISO's needs. This includes gas-fired resources in states without carbon mandates because their attributes cause them to have the highest reliability value. Indeed, we have seen a number of recent announcements by utilities in MISO that intend to invest billions in new gas resources.

These resources in the future could be fired by renewable fuels. Hybrid resources and batteries are also likely alternatives because: (i) their storage can be used to manage congestion and greatly increase their energy and ancillary services market revenues, (ii) they contribute much more to energy adequacy than do intermittent resources, and (iii) they are zero-carbon resources.

Figure 8 includes an alternative to the Future 2A (i.e., the IMM 2A case) that 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.[12] 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 in the outyears are converted to hybrid configurations or are replaced by dispatchable carbon-free resources. We believe this is likely once MISO implements its marginal accreditation of capacity resources, which will provide much lower accreditation for non-hybrid renewable resources in the future.

11 Fixed 17% for wind resources and 50% for solar resources, which falls to 41% and 2032 and 20% by 2042.

12 We do this by replacing the amount of accredited capacity MISO assumed that the new intermittent resources would provide with natural gas, hybrid, and battery resources.

The much more realistic IMM-modified 2A case:

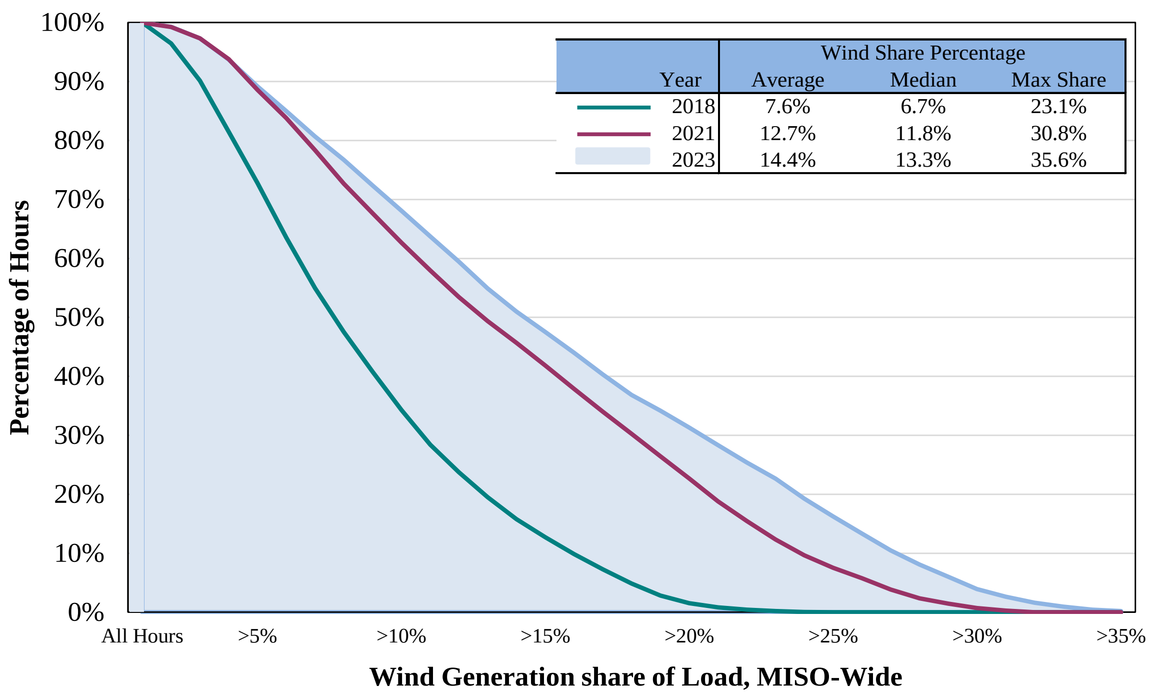
- Lowers costs by $88 billion compared to MISO's Future 2A;
- Satisfies the States' carbon goals and MISO's energy adequacy needs; and
- Is much more consistent with MISO's market incentives that are based on the attributes needed by the system.

Given the importance of Future 2A for MISO's long-term planning, we recommend MISO re-evaluate its futures cases to address these issues. In the alternative, it would be very helpful to adopt an alternative scenario for the cost-benefit analysis similar to the IMM case.

Expansion of Wind Resources

Average hourly wind output decreased slightly in 2023, falling eight percent from 2022 to 10 GW. Wind resources will continue to produce increasing shares of the total generation in MISO in the long term, although this share fell slightly from 16 percent of all energy in 2022 to 15 percent in 2023. Wind generation varies substantially from day to day and often from hour to hour. In some hours, wind generation served over one third of the load in MISO in 2023, which presents increasing operational challenges that MISO must confront. Figure 9 below shows the cumulative share of MISO's load served by wind, and how this share has changed over the past five years. The x-axis represents the percentage of load served by wind. The y-axis shows the percentage of hours during the year when wind output exceeded that share of load.

Figure 9: Share of MISO Load Served by Wind Generation Over Time



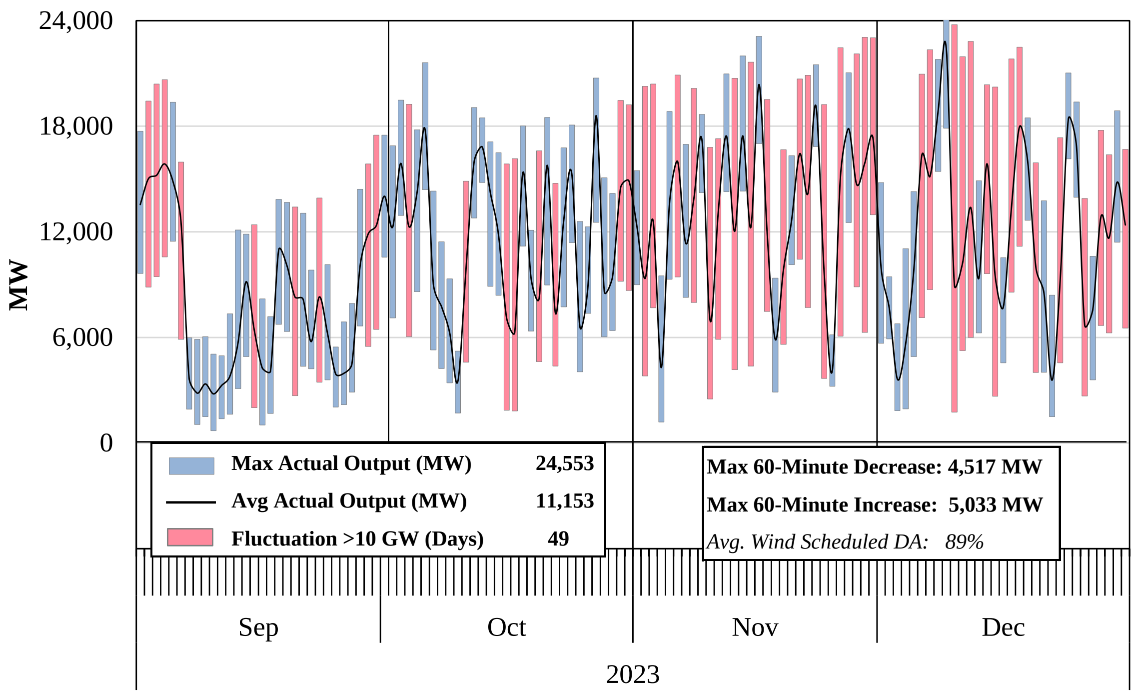
Year	Wind Share Percentage Average	Median	Max Share
2018	7.6%	6.7%	23.1%
2021	12.7%	11.8%	30.8%
2023	14.4%	13.3%	35.6%

This figure shows that wind output as a share of load in MISO has been growing rapidly. The figure shows, for example, that more than 15 percent of the load was served by wind in roughly half of the hours in 2023. To see the changes over time, notice in the figure that for half of the hours, wind output was serving roughly eight percent of the load in 2018, 13 percent in 2021, and more than 14 percent of the load in 2023. This trend is expected to continue along with managing its operational challenges.

Wind Fluctuation. The operational challenges associated with managing wind generation arise because of the substantial uncertainty of the wind output. As uncertainty grows, so do the errors in forecasting the wind output. To illustrate these challenges, Figure 10 shows the daily range in wind output along with the average wind output each day from September through December 2023, a period during which wind output was relatively high. This period included a new all-time peak wind output of almost 25 GW on December 9, 2023, a day when wind served almost 35 percent of the systemwide demand in MISO.

On the days colored pink in the figure, wind output fluctuated by more than 10 GW. MISO has generally been able to manage these increasingly large fluctations in wind output. They will continue to be more challenging and can lead to operational issues when the fluctuations are not forecasted accurately. Sharp changes in output can be more difficult to manage because MISO is limited in how quickly it can move other resources. As the figure reports, wind increased by as much as 5,000 MW in one hour during this period. As wind penetration increases, the need to have other flexible resources available to manage the intermittent output will rise.

Figure 10: Daily Range of Wind Generation Output
September – December 2023



Often the highest output from wind resources occurs in overnight hours. As wind capacity continues to grow, this may place increasing pressure on older, uneconomic baseload resources to cycle off overnight. It also will increase the value of having dispatchable conventional resources that can cycle on and off for much shorter periods. Finally, Figure 10 also shows that MISO continues to experience periods when intermittent output is close to zero. This underscores the importance of having sufficient dispatchable resources available to satisfy the system demands when intermittent generation is not available.

Transmission Congestion Caused by Wind. In addition to the issues caused by the uncertainty of wind output, the concentration of wind resources in the western areas of MISO's system has created growing network congestion in some periods that can be difficult to manage. MISO's Dispatchable Intermittent Resource (DIR) type has been essential in allowing MISO to manage congestion caused by wind output. DIR participation by wind resources increases MISO's control over wind resources by allowing them to be dispatchable (i.e., to respond economically to dispatch instructions). In the longer term, innovative management of the transmission system, including integration with other controllable network facilities (e.g., high-voltage direct current, phase angle regulators, switches, and battery facilities) will be pivotal in integrating much larger quantities of wind resources. We discuss possible approaches in the next subsection.

Penetration of Solar Resources

Figure 8 shows that solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years and dominate the interconnection queue. This influx of solar resources will present new challenges for MISO's operators and its markets. Currently, almost 9 GW of solar resources are operational, the vast majority of which entered in 2023. Solar output peaked at 6.2 GW on June 14, 2024, although the peak solar output will continue to increase with growing solar penetration.

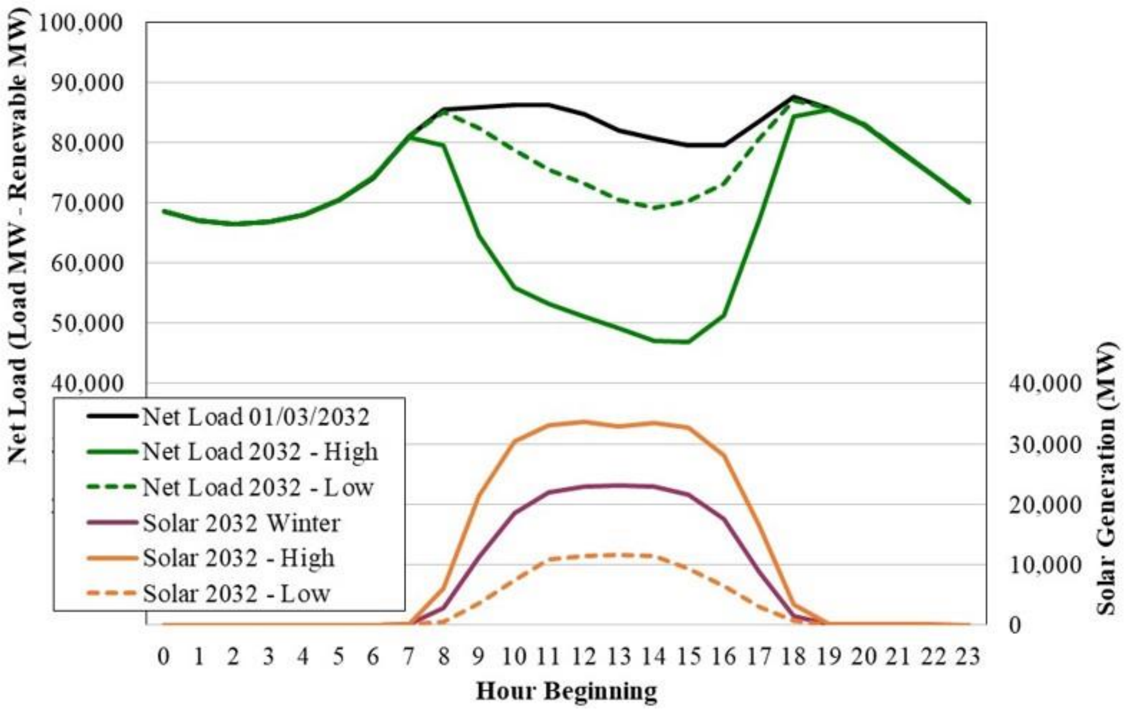
Given the operating profile of solar resources, these resources will lead to significant changes in the system's ramping needs. The morning ramp demand occurs between 6 and 8 a.m. and will continue to mainly be met by dispatchable resources. As solar output peaks in the late morning, dispatchable resources will need to ramp down to balance the solar output. As solar output falls in the evening, a second steep ramp demand will occur. These demands are especially challenging in the winter when the load peaks in the early morning and evening when solar output is low. These ramp challenges have already been observed in solar-rich western markets.

Figure 11 shows the projected "net load" that must be served by conventional resources in MISO under different solar penetration scenarios in the year 2032. In this figure, net load is the system load minus the output of intermittent resources. This curve has been referred to as the "duck curve" because of its shape. This figure is based on MISO's Future 2A projected load on a relatively cold future winter day in January. Data for modeling solar resources is from the Futures Scenario 2A from MISO's MTEP and RIIA processes, which is an intermediate case.

Because solar output from a fixed set of resources can vary substantially, the figure shows a high solar and low solar case under this Futures Scenario.

This figure shows the typical dual peak in load that often occurs in the winter, one in the morning and one in the evening. Because the solar output rises, peaks, and then falls between these two daily peaks, it increases the need for the conventional generation fleet to ramp. In the high solar case, the net load falls sharply after the morning peak as solar output increases.

Figure 11: Net Load in MISO on a Representative Winter Day



Likewise, the net load increases sharply from 4 p.m. to 10 p.m. as evening sets in. The net load that would be served by conventional resources in this case would rise by more than 35 GW. This ramp could be even larger if wind happens to be falling in these hours. This underscores the importance of having generation available and flexible enough to satisfy these needs.

Distributed Energy Resources

Another developing area that MISO is addressing is Distributed Energy Resources (DERs) and Energy Storage Resources (ESRs). 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.[13]

13 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).

According to the 2023 OMS DER Survey, 12.5 GW of DERs currently exist in MISO. Of this, 44 percent is solar PV, 41 percent is demand response, and the rest is 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.

We recommend guiding principles for addressing these challenges of DERs later in this section.

Energy Storage Resources

Order No. 841 required MISO to enable ESRs to participate in the market, recognizing the operational characteristics of ESRs. Figure 8 above shows that MISO forecasts only moderate growth in ESRs over the next decade. Based on the trends in other markets, 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.

B. 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; and
- Implementing the Short-Term Reserve Product and dynamically adjusting the requirements to manage uncertainty; and

As the resource fleet transitions, some needs may arise that are not currently satisfied by the markets, such as voltage support in some locations or inertial support systemwide.[14] We will continue to evaluate these issues and determine, to the extent they arise, whether they would be best addressed through the markets, through non-market settlements, or through interconnection requirements. However, the vast majority of issues that will arise over the next decade can be addressed with the following improvements to the MISO markets in three 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;
   - Implementing a look-ahead dispatch and commitment model in the real-time market;
   - Reforming shortage pricing to compensate resources that are available and flexible and that allow MISO to maintain reliability when shortages arise;
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.
3. Improvements in the Capacity Market
   - Reforming capacity accreditation so that resource capacity credits under Module E accurately reflect reliability values; and
   - Introducing a reliability-based demand curve in the capacity market that will align with the marginal reliability value that capacity provides.

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 12 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

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14 Recent studies have determined that inverter-based resources (IBR) such as intermittent solar and wind, can provide some grid-forming benefits with investment in power electronics. See: https://www.nrel.gov.

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 2023.

Figure 12: Uncertainty and MISO's Operating Requirements
January 2022 to December 2023

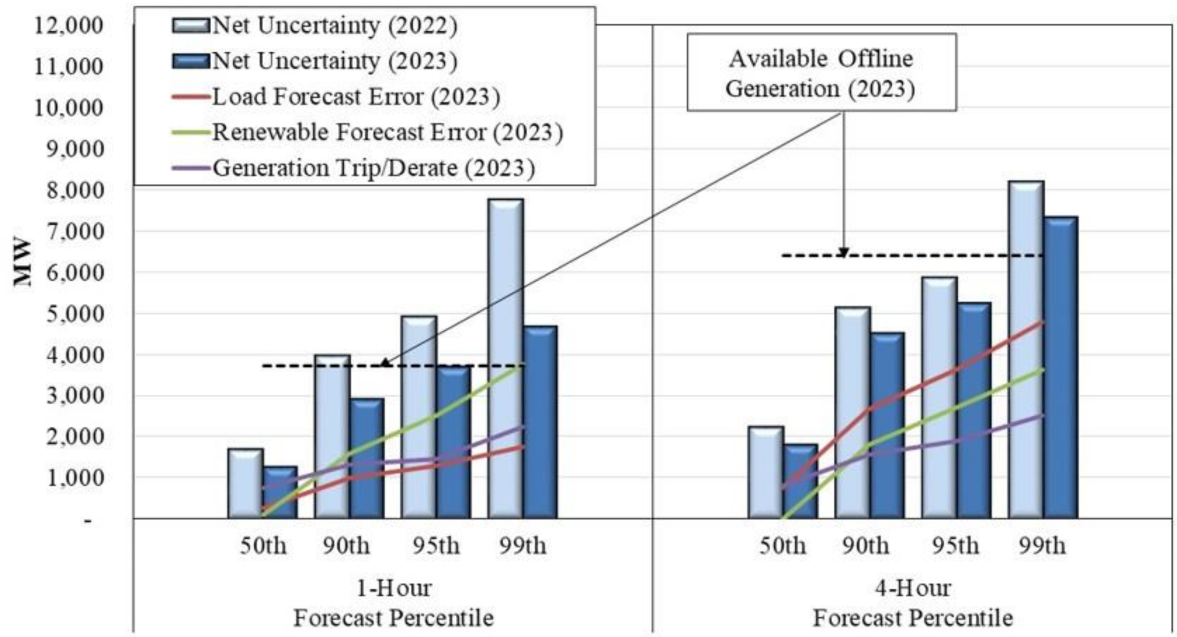


Figure 12 shows that net uncertainty fell in 2023 from 2022, driven by lower generation outages and lower average wind production. MISO commits resources outside of the market to ensure it would have sufficient generation available to respond to uncertainty, which results in RSG costs. Reflecting these needs in a market product would allow prices to efficiently reflect them, result in less 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. MISO has begun to address uncertainty by 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. This product would 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 is illustrated above in Figure 11 showing a ramp need of almost 40 GW in three hours. 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 that will 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 10-minutes to 2 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.

Shortage Pricing in the Energy and Ancillary Services Markets

Efficient shortage prices play a key role in establishing economic signals to guide investment and retirement decisions in the long term, facilitating optimal interchange and generator commitments in the short-run, and efficiently compensating the flexible resources needed to integrate large quantities of renewable resources.

When the system is short of supply, the market will first hold less reserves than required and prices for reserves and energy should reflect the reliability value of the foregone reserves. The shortage value is established in each product's Operating Reserve Demand Curve (ORDC). An efficient ORDC should: a) reflect the marginal reliability value of reserves at each shortage level; b) consider all supply contingencies and uncertainties; and c) have no artificial discontinuities that can lead to excessively volatile outcomes. The marginal reliability value of reserves at any shortage level is the expected value of lost load, which is equal to:

Net value of lost load (VOLL) * the probability of losing load

We recommend that MISO improve its shortage pricing by improving its VOLL and the slope of its ORDC as described below.

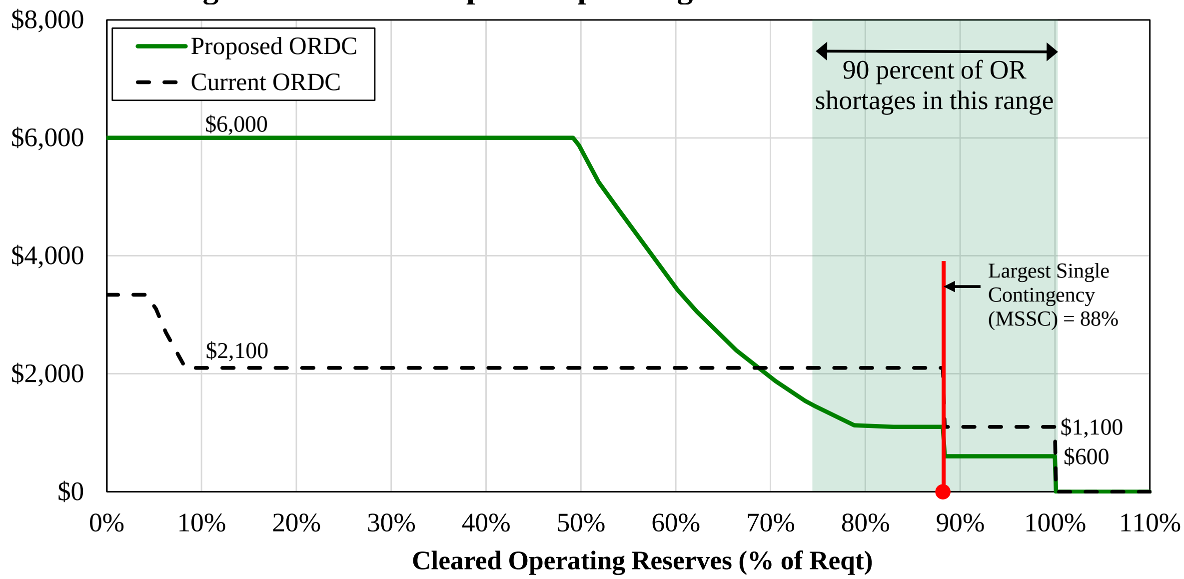
Improving the VOLL. We reviewed the literature and used a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. This study and others estimate VOLLs that vary substantially be customer class. Using the Berkeley Model and MISO data, we estimated a VOLL of close to $35,000 per MWh.[15]

15 The calculation of these values is described in more detail in Section III.B of the Analytic Appendix.

Improving the Slope of the ORDC. The slope of the ORDC is determined by how the probability of losing load changes as the level of operating reserves falls. The probability of losing load depends on the vast combinations of random contingencies and other factors (wind forecast and load forecast errors, and NSI uncertainty) that could occur when MISO is short of reserves. We estimated this probability using a Monte Carlo model that simulates these factors.[16]

MISO's Proposed ORDC. MISO has begun to address these recommendations by estimating an updated VOLL and loss of load probability model for calculating an updated ORDC. It proposes to use an effective VOLL of $35,000 per MWh (consistent with our recommendation) to populate the new proposed ORDC shown in Figure 13 (green line). The figure also shows MISO's current ORDC, which is significantly understated for many shortage quantities.

Figure 13: MISO Proposed Operating Reserve Demand Curve



MISO's proposed ORDC plateaus at $6,000 per MWh, which is justifiable for at least three reasons: (i) very few shortages would be priced in this range; (ii) pricing shortages much higher could result in inefficient interchange; and (iii) higher levels could cause MISO's dispatch model to make inefficient trade-offs between retaining reserves and managing constraints.

In summary, an improved ORDC that better aligns shortage pricing with the marginal reliability value of the foregone reserves will result in more efficient economic signals that govern both short-term and long-term decisions by MISO's participants.

Objectives for Accommodating Distributed Energy Resources

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

16 The simulation to estimate conditional probabilities is described in Section III.B of the Analytic Appendix.

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 provide efficient incentives to invest in DERs and other resources needed for reliability.

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 include four tranches.

Tranche 1, approved in 2022, allocates $10.3 billion in investments to address constraints in the Midwest region. Tranches 2 (Midwest), 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 have concerns in both regards, which we summarize in this section.

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. Therefore, we continue to believe it is important to address these issues with Future 2A.

Many categories of benefits are likely to be overstated. MISO has indicated that it will be estimating nine classes of savings. All of these savings depend on where resources are located on the ISO system. Our most pervasive concern is that MISO's methodologies do not account for market incentives that affect long-term resource citing decisions. MISO uses a single capacity scenario (amounts and locations) – assuming the decision to build or not build the Tranche 2 transmission will have *no effect* on generation decisions. This is not reasonable because it ignores the fact that the local capacity requirements and incentives (locational energy and capacity prices) will compel substantial changes in resource siting decisions. Hence, accurate benefits estimates will require that MISO develop a "no-transmission" base case (No tranche 2). This is necessary to accurately estimate the a) fuel and congestion savings, b) energy savings from reduced losses, and c) capacity savings from reduced losses.

Our most significant concerns with the other classes of benefits include the following three that we recommend eliminating or substantially modifying:

- Avoided capacity costs: MISO's methodology assumes more capacity will be needed if Tranche 2 is not built. However, increased local capacity requirements in constrained zones and energy price signals will shift capacity over time to constrained areas where resources will be fully deliverable. Hence, we recommend eliminating this benefit or modifying it to estimate the cost of the movement of capacity within the Midwest region.
- Decarbonization: Because the dispatch costs of renewable resources include the production tax credits (PTCs) that they receive, the production cost savings captures the decarbonization benefits. Hence, estimating separate decarbonization benefits will double-count these benefits. Because PTCs accurately reflect the social cost of carbon, there is no reasonable basis to calculate additional decarbonization benefits. Hence, we recommend MISO eliminate this class of benefits.
- Mitigation of reliability issues: MISO proposes quantifying this benefit by assuming it will *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. We recommend MISO eliminate this class of benefits *or* quantify savings based on the costs of the next operating action or the costs of the equipment that would address the reliability issues (absent Tranche 2) rather than load shedding.

MISO's proposed scenario analysis will help address the concerns with Future 2A. MISO intends to assess the benefits of the proposed transmission projects using Futures 2A and 1A. Future 1A includes fewer intermittent resources. However, it also includes fewer dispatchable and storage resources and lower load than the IMM Future 2A. These differences may inflate transmission benefit estimates in this scenario, but they will likely be more accurate than the benefits calculated based on Future 2A.

Benefits should be calculated for groups of projects. It will be essential to calculate the benefits for individual groupings of investments in Tranche 2 to ensure that only those investments that qualify as "no regrets" investments are billed to MISO's customers, while investments that have little or no value in a more realistic scenario are removed from the portfolio.

We recommend that MISO upgrade its analysis to address these factors in its analyses of the Tranche 2 projects and the future Tranche 3 and 4 projects. This will help ensure that the transmission upgrades are economic and do not undermine the MISO markets.

3. Improvements in the Capacity Market

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 verticallyintegrated 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 and b) proposing reliability-based demand curves. A last key improvement relates to how it accredits its capacity resources. Accurate accreditation is needed to send efficient incentives to developers and inform states' and utilities' integrated resource planning processes to ensure that future investment will satisfy the reliability needs of the MISO region.

A resource's true reliability value is its expected availability to provide energy or reserves when the system is at risk of load shedding. Importantly, the hours of greatest reliability risk are affected by the supply portfolio and the output profile of the portfolio. Because the value of each additional MW is determined in part by the portfolio of existing generation, this is characterized as a "marginal value". RTOs must utilize methods that determine the marginal value of different types of resources to accredit them accurately.

MISO recently filed to implement a marginal accreditation framework that determines a resources' accreditation based on their expected availability during hours with the highest expected reliability risks.[17] Since such risks tend to peak when intermittent output is low, marginal resource accreditation tends to produce relatively low values for intermittent resources. However, it will address other types of generation, such as natural gas-only resources in the winter. Increasingly, critical reliability hours in the winter are likely to occur when natural gas availability is limited, causing gas-fired resources that rely on non-firm fuel purchases to provide diminishing levels of reliability. This must be reflected in the capacity accreditation framework to ensure the market will maintain resources with the attributes needed to maintain reliability.

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. In this section, we discuss and recommend the remaining changes that will be needed to successfully navigate this clean energy transition, the most important of which is: a) improving MISO's shortage pricing, b) implementing a real-time look-ahead dispatch and commitment model, and c) introducing an uncertainty product. It will also be very important for MISO to receive approval for and implement its proposed marginal accreditation framework.

[17] 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.[18] The real-time market clears based on actual physical supply and demand, settling any deviations from day-ahead contracts at real-time prices.[19] The performance of both markets is essential.

Day-ahead market performance is important 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;[20]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market – 98.7 percent in 2023 (net of virtual transactions); and
- The value of entitlements of firm transmission rights are 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.A, falling substantially in 2023 as natural gas prices decreased and coal supply constraints eased. Average day-ahead energy prices across MISO decreased 52 percent from 2022 to $31 per MWh. Congestion caused day-ahead prices at MISO's hubs to range on average from $27 per MWh at the Arkansas Hub to roughly $33 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

18 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.

19 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.

20 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.

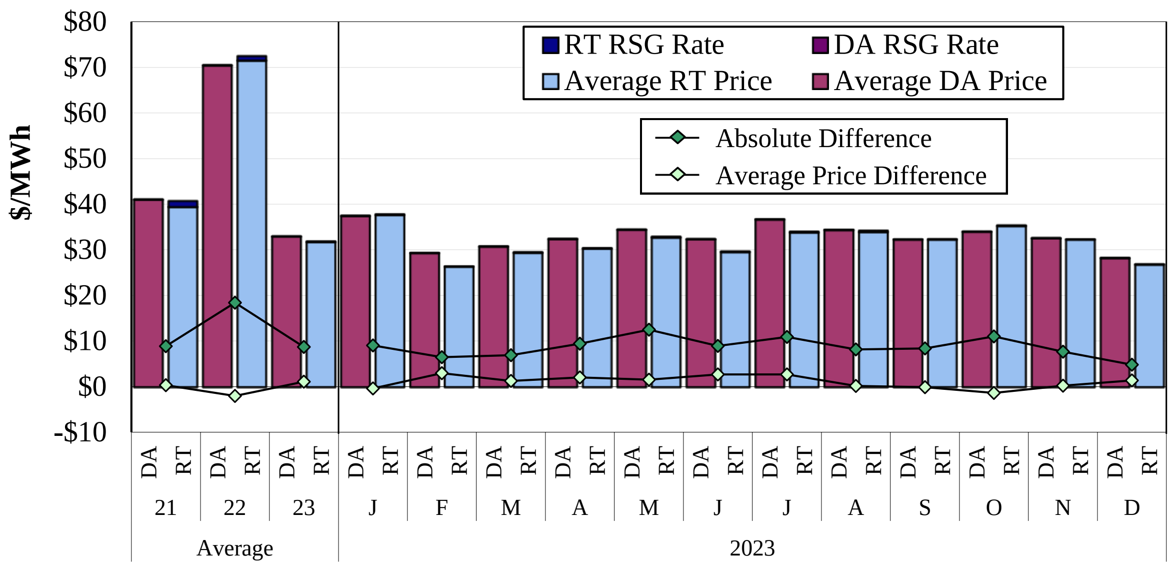
supply tend to occur at the top of the hour when day-ahead schedules change, prices tend to spike at these times. We had previously recommended MISO evaluate the feasibility of transitioning to a 15-minute day-ahead market to improve the operation of the system, but MISO determined that it is not currently 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 for electricity, 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 14 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 14: Day-Ahead and Real-Time Prices at Indiana Hub

2021–2023



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

Indiana Hub	1	-3	3	-1	11	4	7	5	9	8	0	0	-4	1	5
Michigan Hub	1	-1	3	5	12	6	4	1	6	8	2	-5	-7	1	3
Minnesota Hub	-1	0	-1	-1	-7	-6	-10	13	-4	4	-6	-2	-3	7	1
Arkansas Hub	-3	-2	2	-1	3	5	0	5	6	5	2	-3	-4	3	5
Louisiana Hub	-1	-1	4	0	6	1	3	4	11	13	4	0	-3	6	3
Texas Hub	-2	-1	4	1	7	5	5	4	7	11	4	3	-3	5	3

These results indicate that price convergence was good overall. Day-ahead prices were about three percent lower than real-time prices after adjusting for the real-time RSG costs, which averaged $0.16 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 15 shows the average offered and cleared virtual supply and demand. The figure separately shows financial-only participants and physical participants.

Figure 15: Virtual Demand and Supply in the Day-Ahead Market
2023

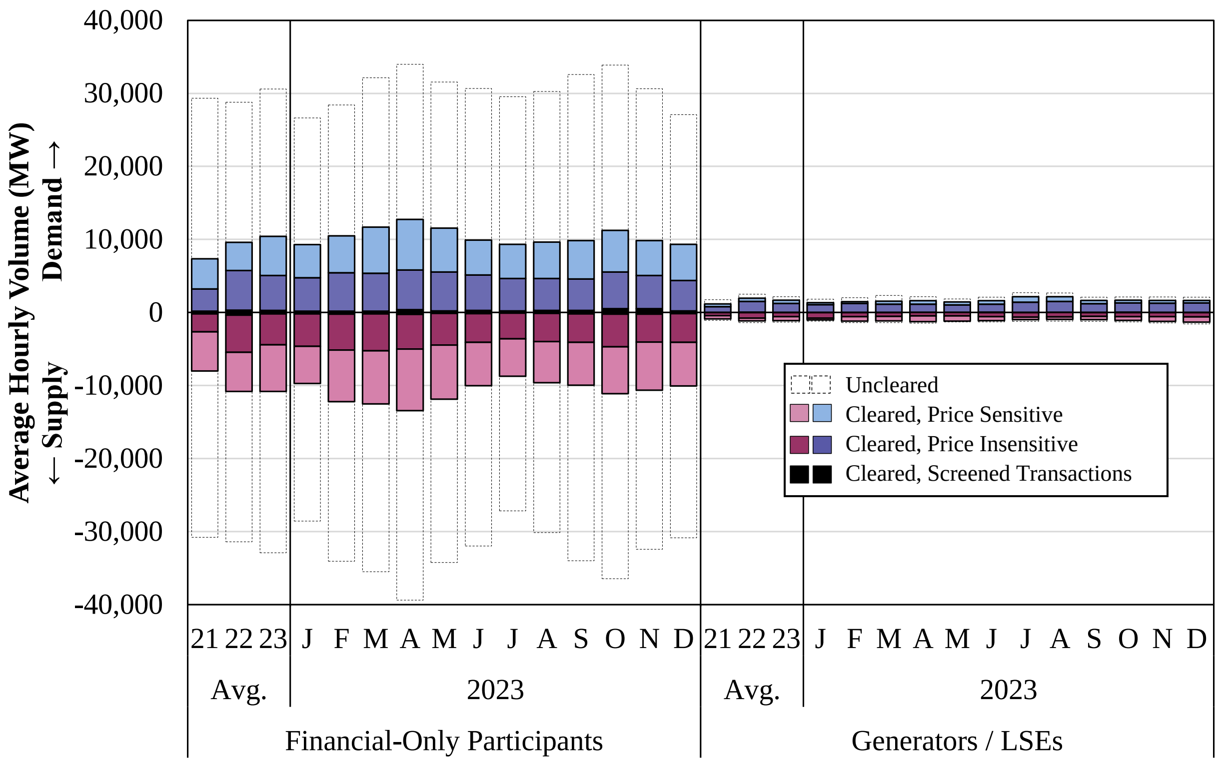


Figure 15 shows that financial participants continue to account for the vast majority of virtual transactions, and the limited quantities scheduled by physical participants fell roughly 10 percent from 2022. In total, cleared transactions increased by two percent, driven by increases in cleared virtual activity of two percent in the Midwest and of 11 percent in the South.

Figure 15 indicates the following additional key findings:

- 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 23 percent from 2022 to 1,590 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 2.1 percent of all transactions and raised no concerns in 2023.

Virtual Activity and Profitability

Gross virtual profitability fell 49 percent in 2023 to average $0.70 per MWh, down from $1.37 per MWh in 2022. Both virtual demand and virtual supply profitability decreased. Some of this decrease was attributable to high profits during Winter Storm Elliott in December 2022, when real-time price spikes raised virtual demand profitability to average almost $14 per MWh.

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 $0.78 per MWh compared to $0.13 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. 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
2023

Market	Virtual Load		Virtual Supply	
	MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit
MISO	16.1%	$0.27	15.9%	$1.14
NYISO	7.2%	-$0.76	8.6%	$0.10
ISO-NE	4.0%	-$2.09	6.1%	$1.28
SPP	9.2%	$1.05	14.3%	$3.74
PJM	5.5%	-$0.69	5.1%	$1.29

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 2023. We determined that 57 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 57 percent of all virtual transactions were efficiency-enhancing. Convergent profits were positive on net for all virtual transactions by $88 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 2023

Transaction Category	Financial Participants			Physical Participants		
	MWh	Convergent Profits	Rent-Seeking	MWh	Convergent Profits	Rent-Seeking
Efficiency Enhancing (Profitable)	93,272,998	$1,188.7M	-$14.9M	10,794,159	$98.2M	-$.3M
Efficiency Enhancing (Unprofitable)	13,847,045	-$94.5M	$14.0M	1,830,789	-$8.5M	$1.4M
Not Efficiency Enhancing (Profitable)	5,368,303	-$24.4M	$56.5M	671,408	-$1.7M	$3.7M
Not Efficiency Enhancing (Unprofitable)	73,383,237	-$978.9M	-$1.9M	11,100,800	-$90.7M	$1.1M
Total	**185,871,584**	**$90.9M**	**$53.6M**	**24,397,157**	**-$2.7M**	**$5.9M**

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 2023.

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.B 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

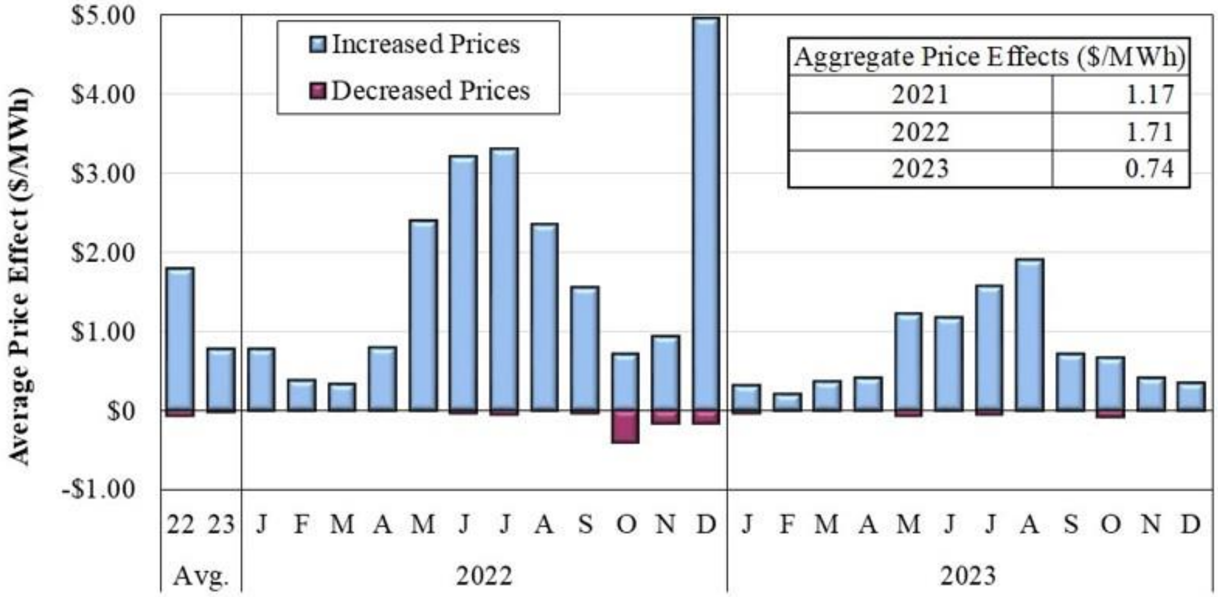
Beyond shortage pricing, a key element of MISO's real-time pricing is its Extended Locational Marginal Pricing (ELMP) algorithm that was implemented in March 2015. While MISO's dispatch model calculates "ex ante" real-time prices every five minutes, these real-time prices are re-calculated by the ELMP 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 reforms pricing by allowing Fast-Start Resources (FSRs) and emergency resources to set prices when needed and economic to satisfy the system's needs.[21]

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

21 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.

generation and interchange. Although FSRs may not appear to be marginal in the five-minute 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 2023.

Figure 16: The Effects of Fast Start Pricing in ELMP
2022–2023



% of Intervals Affected by > +/- $0.10

SMP Increase	57	53	56	49	42	54	58	60	59	51	75	58	63	55	42	37	59	46	58	60	60	61	52	60	55	46
SMP Decrease	1	1	0	0	0	1	1	4	1	1	2	0	4	1	0	0	3	1	1	1	1	0	0	2	1	1

Figure 16 shows that the effects of ELMP on real-time energy prices fell 57 percent in 2023. This decrease was due to lower gas prices in 2023 and MISO not experiencing a price event of the magnitude of Winter Storm Elliott in December 2022. The performance of ELMP has been good partly because of the improvements MISO 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 other 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.

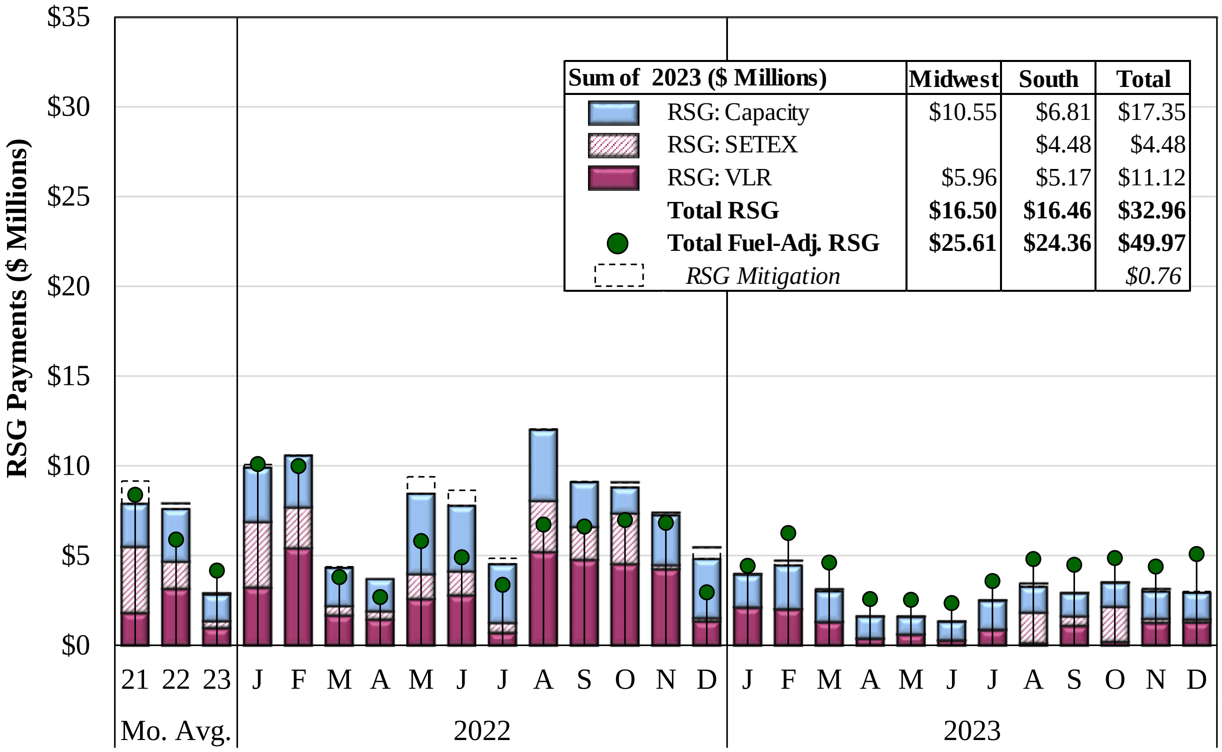
Resources committed before or in the day-ahead market may receive a day-ahead RSG payment as needed to recover their as-offered costs. Resources committed by MISO after the day-ahead market receive a real-time RSG payment as needed to recover their as-offered costs. The day-ahead RSG costs for economic 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 17 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.[22] The maroon bars show all the RSG paid to units started for VLR before the day-ahead market cleared, except that the VLR costs incurred for the Western Op Guide (replaced by the Southeast Texas (SETEX) Op Guide in August 2022) 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 62 percent in 2023 to total $33 million. Around 30 percent all day-ahead VLR costs accrued to units in two load pockets in MISO South, while an additional 32 percent accrued to units committed for transmission work in Michigan. Most of the day-ahead RSG categorized as for capacity was paid to cover the resources' startup costs.

Figure 17: Day-Ahead RSG Payments
2022–2023

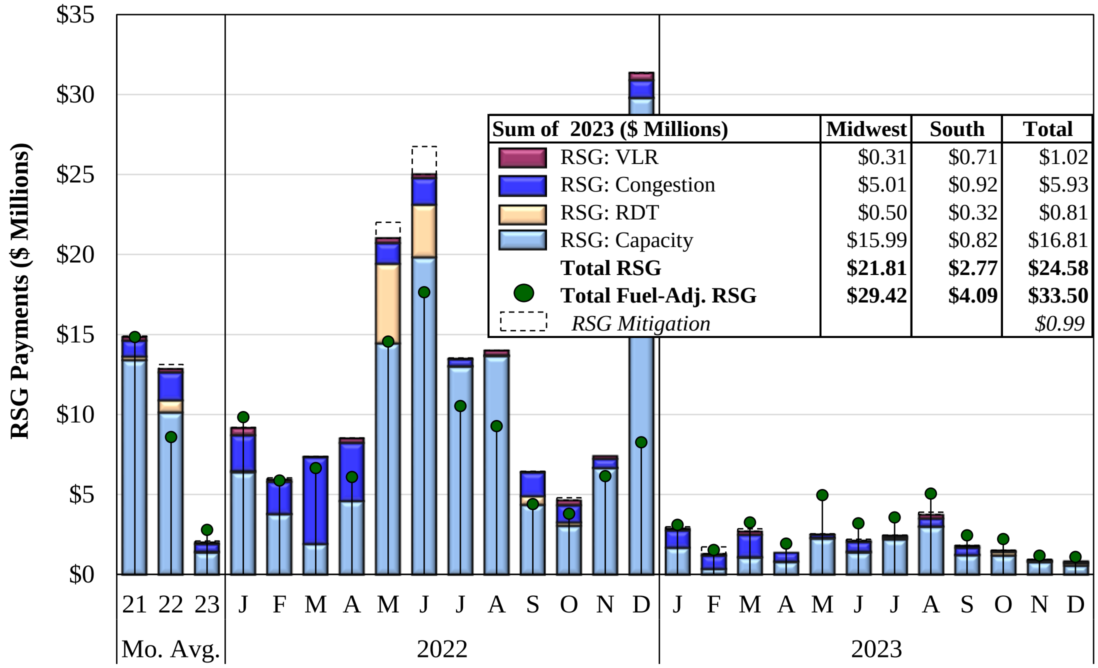


Sum of 2023 ($ Millions)	Midwest	South	Total
RSG: Capacity	$10.55	$6.81	$17.35
RSG: SETEX		$4.48	$4.48
RSG: VLR	$5.96	$5.17	$11.12
Total RSG	**$16.50**	**$16.46**	**$32.96**
Total Fuel-Adj. RSG	**$25.61**	**$24.36**	**$49.97**
RSG Mitigation			*$0.76*

Figure 18 shows the same categories of real-time RSG payments and includes RSG costs for units committed to: a) manage congestion, and b) manage RDT flows or create regional reserves. The figure shows that nominal real-time RSG payments fell 84 percent in 2023, largely attributable to lower gas prices and improvements to MISO's commitment practices. In addition, some of this reduction is due to significant winter storms in prior years that led to high RSG payments, including $100 million in Winter Storm Uri in 2021 and $24 million during Winter Storm Elliott.

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

Figure 18: Real-Time RSG Payments
2022–2023



We worked closely with MISO in 2023 to improve the resource commitment processes, and a significant portion of the reduction in RSG is attributable to changes that MISO made. In our prior reports, we showed that real-time commitments and associated RSG costs rose sharply in early 2021 and into 2022. We found that a large share of these out-of-market commitments and the RSG costs were not necessary to meet MISO's real-time reliability needs. This was a key finding because excess supply in real time tends to lower real-time prices, raise RSG, and weaken the incentive to fully schedule resources in the day-ahead market. Hence, we recommended a number of improvements to reduce unnecessary commitments, including:

- Eliminating the use of manual inputs to the LAC model to address uncertainty since they cause it to recommend unnecessary commitments, increasing STR requirements instead.
- Deferring commitments that do not need to be made immediately given resources' start-up times and decommitting them when no longer needed.
- Using reserve demand curves and TCDCs in the LAC and other commitment models that are more closely aligned with the market demand curves.

MISO created a team to evaluate existing tools and operating practices and has worked with the IMM on these recommendations. Many were implemented in 2023 and account for much of the sharp decline in real-time RSG.

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 and 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 Uri in February 2021 and Winter Storm Elliott in December 2022, given the magnitude of the payments during those storms.

Table 4: Price Volatility Make-Whole Payments ($ Millions)
2021–2023

	DAMAP		RTORSGP		Total	Market-Wide Volatility	Locational Volatility
	Midwest	South	Midwest	South			
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*		
2021	$33.0	$14.2	$4.0	$2.1	$53.3	13.4%	14.3%
WS Uri	$6.5	$6.9	$0.0	$1.3	$14.7		

PVMWPs fell 49 percent from 2022. Over 15 percent of the annual DAMAP in 2021 occurred in February 2021 when prices reached $3,500 per MWh (VOLL) for several hours during load shed conditions, while nearly a quarter of the annual DAMAP in 2022 occurred in December when MISO experienced prolonged shortage pricing and emergency pricing during Winter Storm Elliott. Some of the year-over-year decrease observed in 2023 was due to lower energy prices resulting from lower fuel costs. We identified a settlement flaw that resulted in over $150,000 in unjustified DAMAP to market participants that was clawed back in 2023.

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, 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 403 MW below its contractual limit in 2023. 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 917 MW in the South to North direction in 2023, while flows in the North to South direction were generally correlated with wind output. Currently, all wind resources in MISO are in the Midwest region, 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 Net Dragging
2019–2023

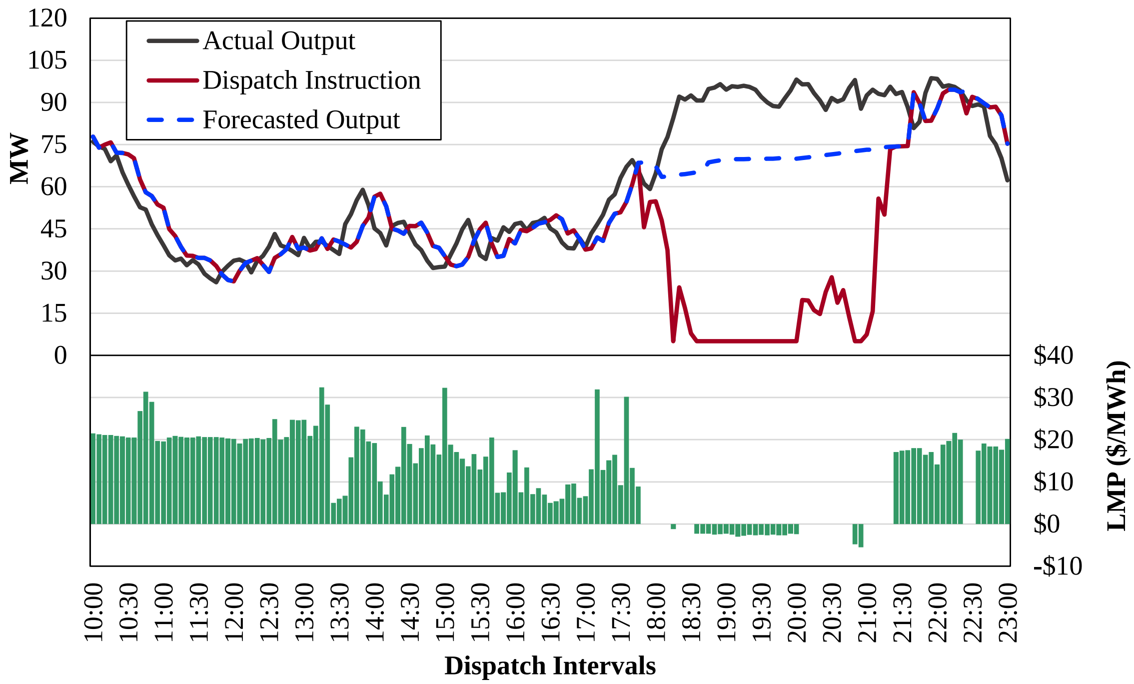
	5-min Dragging		60-min Dragging		Worst 10%	
	Ramp Hours	All Hours	Ramp Hours	All Hours	Ramp Hours	All Hours
2023	480	471	833	763	1,159	1,098
2022	637	660	1,049	1,009	1,341	1,275
2021	611	629	956	908	1,338	1,290
2020	573	563	957	862	1,289	1,193
2019	525	526	851	787	1,163	1,078

Table 5 shows that the 60-minute dragging in all hours decreased 24 percent from 2022 to 2023. 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 19 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 resources' 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. In reality, the congestion was more severe because the excess output 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 19: 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 price 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 resource's 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 different 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.

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

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 UDS. 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 UDS; 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. Our analysis shows large offset increases sometimes lead to operating reserve shortages and associated price spikes. Conversely, offset reductions or lower than optimal offset values sometimes mute legitimate shortage pricing. 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 by the fall. 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
2018–2023

	2018-2021			2022			2023		
	Annual Starts	**% of Starts**	**Net Rev. ($/MWh)**	**Starts**	**% of Starts**	**Net Rev. ($/MWh)**	**Starts**	**% of Starts**	**Net Rev. ($/MWh)**
Regulated Utilities	1765		**$9.43**	1765		**$22.41**	1555		**$5.75**
Profitable Starts	1533	86%		1635	93%		1337	86%	
Offered Economically	*735*	*38%*		*754*	*43%*		*686*	*44%*	
Must-Run and profitable	*798*	*47%*		*881*	*50%*		*651*	*42%*	
Unprofitable (Must Run)	232	14%		130	7%		218	14%	
Merchants	168		**$11.06**	84		**$30.42**	42		**$6.75**
Profitable Starts	167	100%		84	100%		41	98%	
Offered Economically	*153*	*90%*		*84*	*100%*		*39*	*93%*	
Must-Run and profitable	*14*	*10%*		*0*	*0%*		*2*	*5%*	
Unprofitable (Must Run)	1	0%		0	0%		1	2%	

Table 7 shows that falling natural gas and energy prices in 2023 caused coal resources to be less profitable than in recent years – their net revenues fell to around $6 per MWh on average – much lower than the average net revenues in prior years. Although coal resources were much more economic in 2022, fuel limitations and other supply chain issues limited their output.

Table 7 also shows that the share of resources running profitably fell in 2023 as profitability declined. However, 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 93 percent of hours in 2023 and were profitable in 98 percent of their run hours.

H. Wind Generation

As discussed in Section III.A, 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 2023. Section III.A 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

	Name Plate Capacity	Avg. Output (GW)			RT Seasonal Avg. Output (GW)			RT Top 5% Hourly Avg. Output (GW)			2 Hour Forecast Error (%)	
		RT	DA	%	Jan.-Apr.	May-Aug.	Sep.-Dec.	Jan.-Apr.	May-Aug.	Sep.-Dec.	Avg. Error	Abs. Avg.
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%
*%**	*2%*	*-8%*	*-9%*		*-5%*	*-15%*	*-6%*	*1%*	*-1%*	*-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%
2020	24,450	8.1	6.6	-19.2	8.4	6.5	9.5	16.1	13.9	17.4	-2.0%	7.6%

Note 1: % Change between 2022 and 2023.*

Wind Output Trends

Average wind output decreased eight percent from 2022 after growing rapidly in previous years, having increased 74 percent between 2019 and 2022. This is likely due to the El Nino climate patterns that began during the summer months which tend to cause lower prevailing winds. 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 return in 2024 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.A. 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 2023 exceeded eight percent. On a high-wind day, this error would approach 2000 MW and we have recently seen two-hour ahead forecast errors exceeding 5000 MW. 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 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.

We have shown in prior reports that MISO could improve the real-time forecasts by:

- Reducing the time lag between the most recent output observation and the real-time dispatch model run; and
- Improving the persistence algorithm to account for how the wind resources have been moving leading up to the most recent observations.

These improvements together would greatly improve MISO's real-time wind forecasts. Therefore, we continue to recommend that MISO pursue these improvements, which may be facilitated by bringing the real-time forecasts in-house. This would eliminate some of the time lag and give MISO more control over the persistence algorithm, allowing it to optimize it.

Wind Scheduling in the Day-Ahead Market

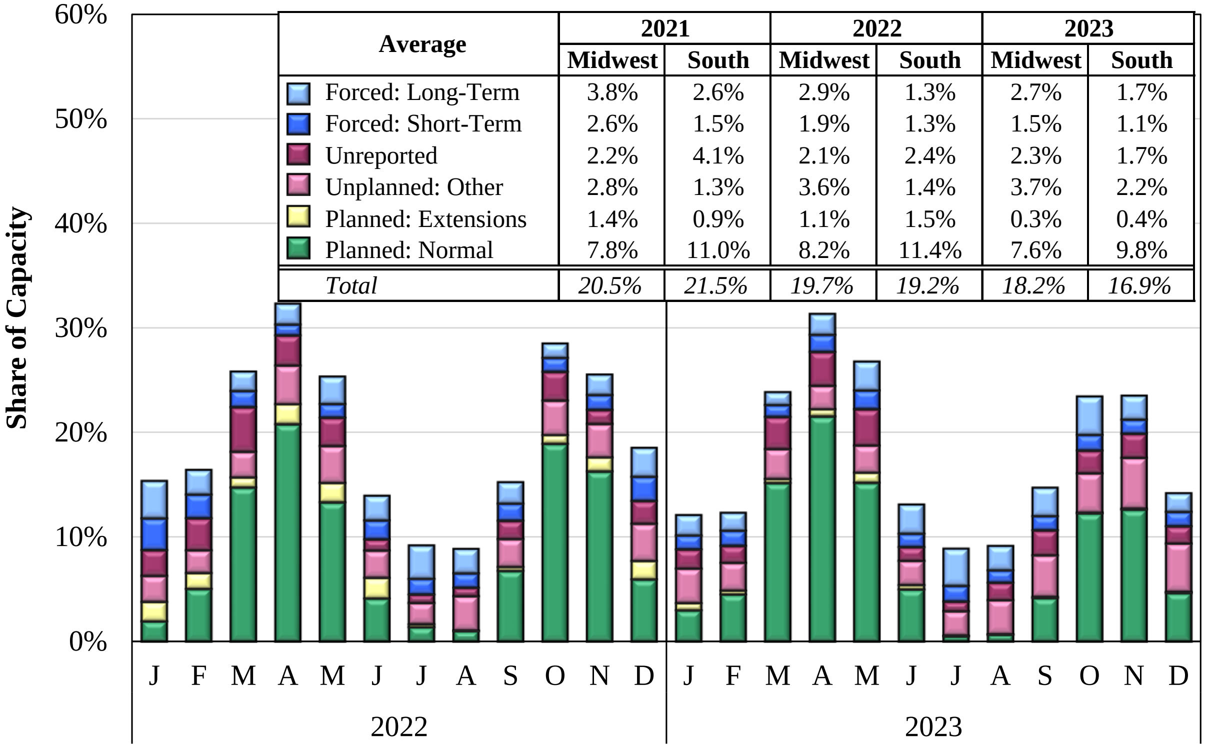
Table 8 shows that wind suppliers generally schedule less output in the day-ahead market than they actually produce in real time. Under-scheduling of wind averaged roughly 1,200 MW in 2023. This can be attributed to suppliers' contracts and financial risks related to RSG cost allocations when day-ahead 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 $82 million on a total of 353 wind-impacted constraints, with over half 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 20 shows outage rates in MISO Midwest and MISO South from 2021 to 2023.

Figure 20: Generation Outages
2021–2023



Average	2021 Midwest	2021 South	2022 Midwest	2022 South	2023 Midwest	2023 South
Forced: Long-Term	3.8%	2.6%	2.9%	1.3%	2.7%	1.7%
Forced: Short-Term	2.6%	1.5%	1.9%	1.3%	1.5%	1.1%
Unreported	2.2%	4.1%	2.1%	2.4%	2.3%	1.7%
Unplanned: Other	2.8%	1.3%	3.6%	1.4%	3.7%	2.2%
Planned: Extensions	1.4%	0.9%	1.1%	1.5%	0.3%	0.4%
Planned: Normal	7.8%	11.0%	8.2%	11.4%	7.6%	9.8%
Total	*20.5%*	*21.5%*	*19.7%*	*19.2%*	*18.2%*	*16.9%*

Figure 20 shows that outage rates in 2023 were slightly lower than in 2022. 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.

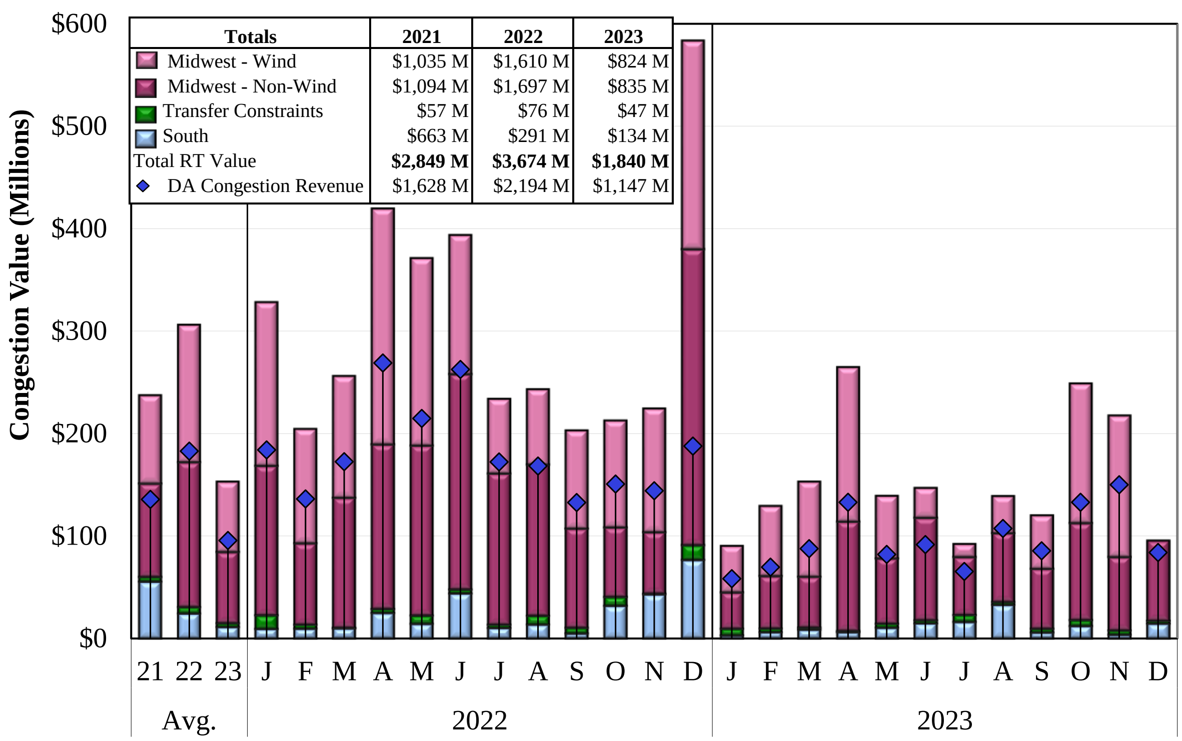
V. Transmission Congestion and FTR Markets

To avoid violating transmission constraints, the MISO markets establish resource dispatch levels and calculate associated transmission congestion costs to keep power flows within transmission operating limits. Transmission congestion arises when network constraints prevent MISO from dispatching the lowest-cost units to meet demand. The resulting "out-of-merit" costs incurred to avoid violating transmission constraints are reflected in the marginal congestion component (MCC) of the LMPs (one of three LMP components). The MCCs can vary widely across the system; they 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 generation to manage network congestion and provide economic signals that facilitate efficient investment and maintenance of resources.

A. Real-Time Value of Congestion in 2023

The value of real-time congestion is calculated as the product of 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 21 shows the monthly real-time congestion value over the past two years along with day-ahead congestion revenues.

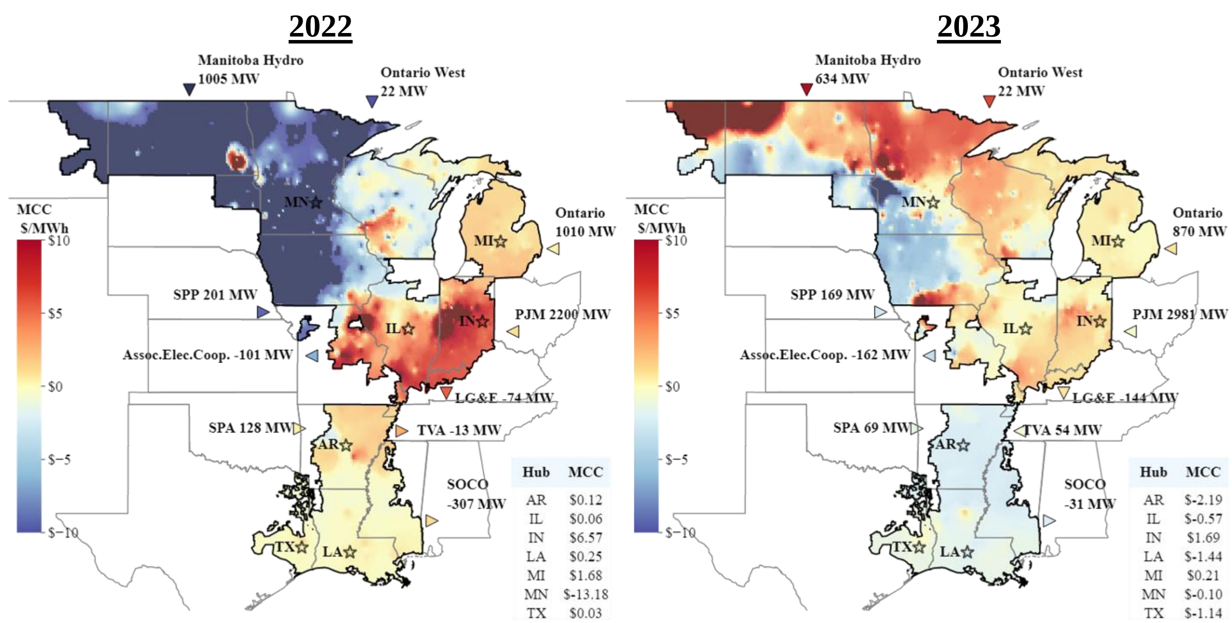
Figure 21: Value of Real-Time Congestion
2022–2023



The total value of real-time congestion fell by half in 2023 from $3.6 billion to $1.8 billion, which is consistent with lower average wind output and lower natural gas prices in 2023. In addition, MISO did not experience extreme weather events like the December 2022 Winter Storm Elliot that contributed to more than $350 million in congestion across just two days. Although overall congestion was lower, wind-driven congestion remained a large share of the total – roughly 45 percent of all real-time congestion in both 2023 and 2022. Continued expansion of nearby wind resources in SPP and PJM, as well as retirements in recent years of key coal and gas resources that had previously provided relief on affected constraints is likely to increase wind-related congestion in future years.

Figure 22 shows the locational differences in the average MCCs of MISO's LMPs in 2022 and 2023. Warmer colors indicate locations where the MCCs are positive and increase LMPs, while cooler colors indicate locations with negative MCCs that lower LMPs.

Figure 22: Average Real-Time Congestion Components in MISO's LMPs



This figure shows a significant change in congestion patterns in the North region, year over year. In the summer, imports from Manitoba fell sharply as drought conditions limited hydroelectric generation in the province. Throughout late summer and early fall, when the drought was most severe, MISO exported to Manitoba on average, reversing the typical interface flows. Low average wind output combined with generator outages and retirements in the North exacerbated the impacts of the changes in flows over the Manitoba interface.

Overall, the high congestion in recent years underscores the importance of improving the utilization of MISO's transmission network through improved operations and rates, which we discuss later in this section.

B. 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 FTRs (i.e., to pay 100 percent of 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:

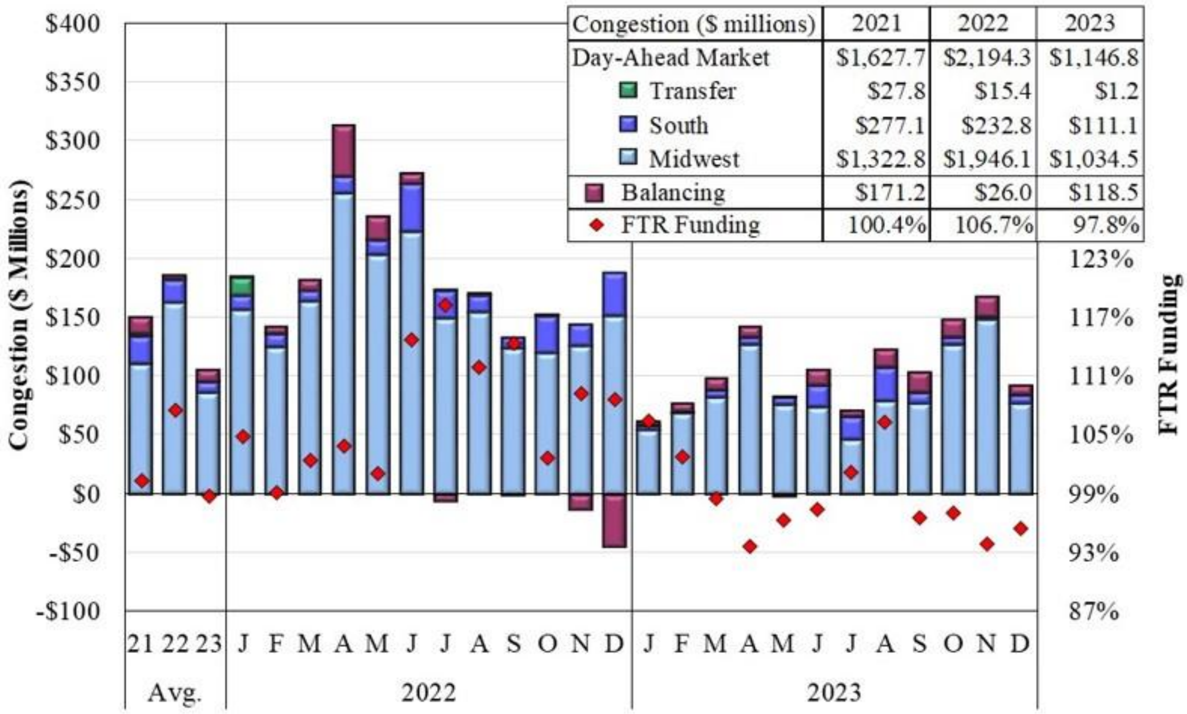
- *FTR Funding*: If MISO does not collect enough congestion in the day-ahead market to satisfy the FTR entitlements, FTR funding will be less than 100 percent, indicating that MISO issued more FTRs than the day-ahead network model could accommodate; and
- *Balancing Congestion*: If day-ahead schedules 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 23 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 2023. Day-ahead congestion costs decreased by 48 percent to $1.1 billion in 2023, which was 62 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 entitlements to flows on the MISO system to SPP and PJM that do not pay for congestion up to the entitlement level.

Figure 23 shows that day-ahead congestion fell in 2023, consistent with the real-time congestion patterns discussed above. It also shows that FTR funding fell and resulted in underfunding, and balancing congestion increased. We discuss these two classes of results in the following subsections.

Figure 23: Day-Ahead and Balancing Congestion and FTR Funding
2021–2023



Note: Funding surplus may be greater than the difference between day-ahead congestion and obligations to FTR holders because it includes residual revenue collections from the FTR auctions.

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.

In 2023, 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. Outages and M2M coordination issues contributed to the shortfalls in 2023:

- Rescheduled transmission outages and topology changes between MISO's FTR market and the day-ahead market account for more than $60 million of shortfalls in the spring;
- In the fall, an inaccurately modeled outage accounted for $51 million in shortfalls on one constraint; and
- The Charlie Creek–Watford M2M constraint was among the most under-funded constraints in late 2023, which from the addition of a 220-MW crypto-currency load in SPP, whose congestion impact was not anticipated in the FTR auction. MISO sought to discontinue M2M coordination on the constraint, which was underfunded by $15 million.

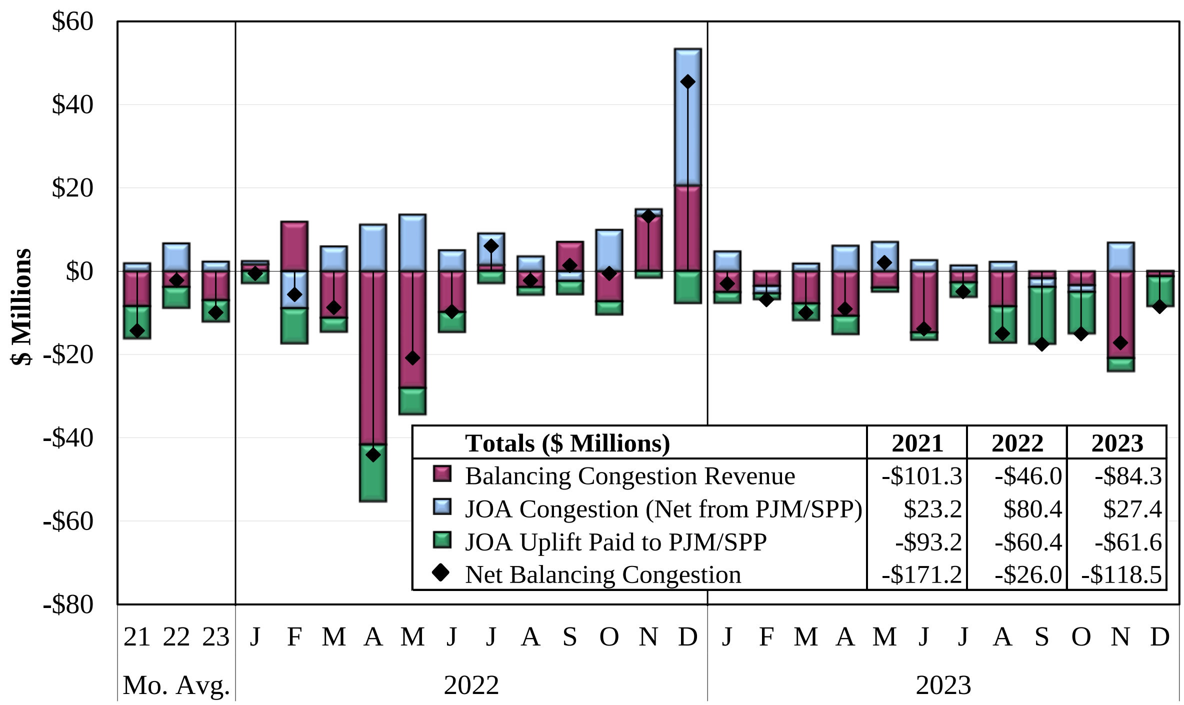
Offsetting these shortfalls, FTRs over the transfer constraint (i.e., the RDT) between the South and Midwest regions are often overfunded because they can bind in both directions. This bidirectionality causes FTR paths across the transfer constraints to be undersubscribed and to generate substantial 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 limit reductions, loop flows that were not fully anticipated day-ahead, or real-time constraints bind that were not modeled in the day-ahead market. Net negative balancing congestion are 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 minimize it by pursuing maximum consistency between the day-ahead and real-time market models. Figure 24 shows the 2022 through 2023 monthly balancing congestion costs incurred by MISO, which include the JOA payments to and received from SPP and MISO.

Figure 24: Balancing Congestion Revenues and Costs
2021–2023



Net balancing congestion was negative $93 million and larger in 2023 than in 2022:

- Balancing congestion revenue shortfall of $84 million (83 percent larger than 2022) suggests increased unanticipated congestion in the real-time market, resulting in more limited power flows than was reflected in the day-ahead market.
- Net JOA congestion payments from PJM and SPP fell to $27 million in 2023. This was down from $80 million in 2022, much of which occurred during Winter Storm Elliot.
- MISO's JOA payments to SPP and PJM were comparable to 2022 although overall system congestion was lower in 2023. In 2023, payments were inflated, in part, because of unjustified payments from MISO for SPP's Charlie-Creek Watford constraint that we discuss in detail later in this section.

FTR Market Performance

An FTR represents a forward purchase of day-ahead congestion. These are instrumental in allocating and pricing transmission rights. Because transmission customers pay for the embedded costs of the transmission system, they are 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 FTRs or to convert their ARRs into FTRs directly 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.[23]

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 planning year.

FTR Market Profitability

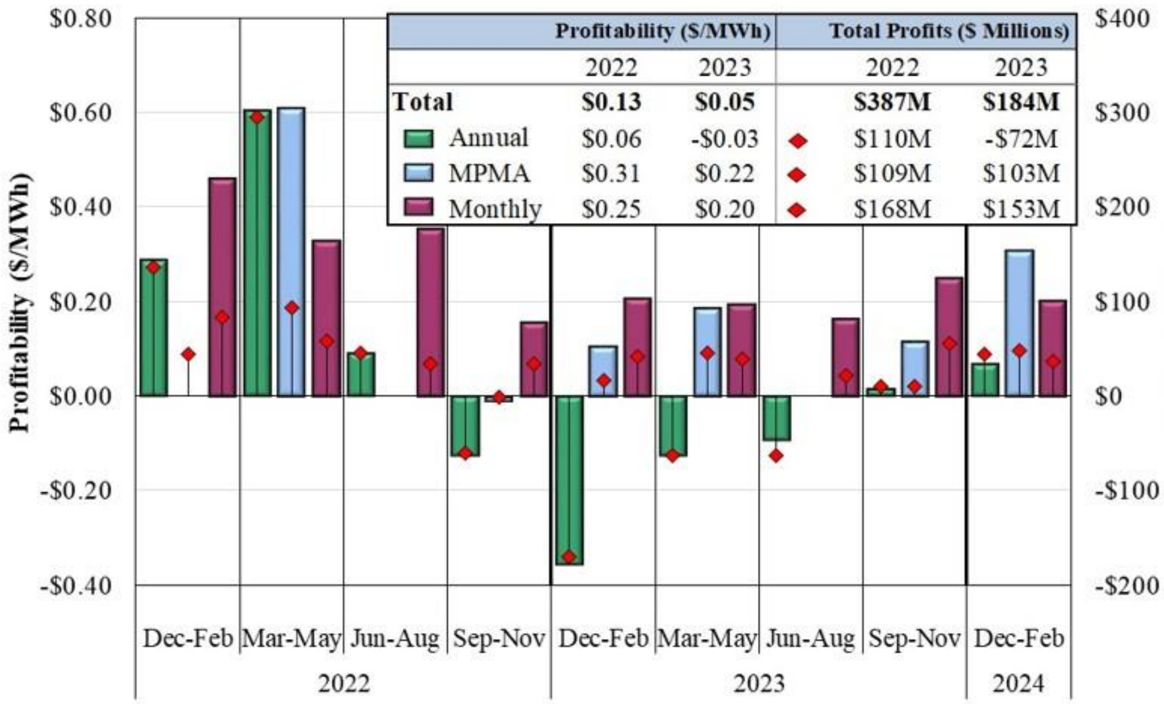
Figure 25 shows our evaluation of the profitability of FTRs in these auctions by showing the seasonal profits for FTRs sold in each market in the bars. The profit margin for each class of

23 These variations can be minimized if MISO uses the most up-to-date outage information in its FTR modeling processes. To facilitate the FTR process, market participants are required to report all known planned outages 12 months in advance even when specific dates have not been finalized. Longer notice is preferred since the ARR allocation process begins 16 months before the FTR year.

FTRs is shown in the red diamonds. For comparison purposes, profitability of monthly FTRs purchased in the MPMA are aggregated seasonally in this figure.

Figure 25: FTR Profits and Profitability

2022–2023

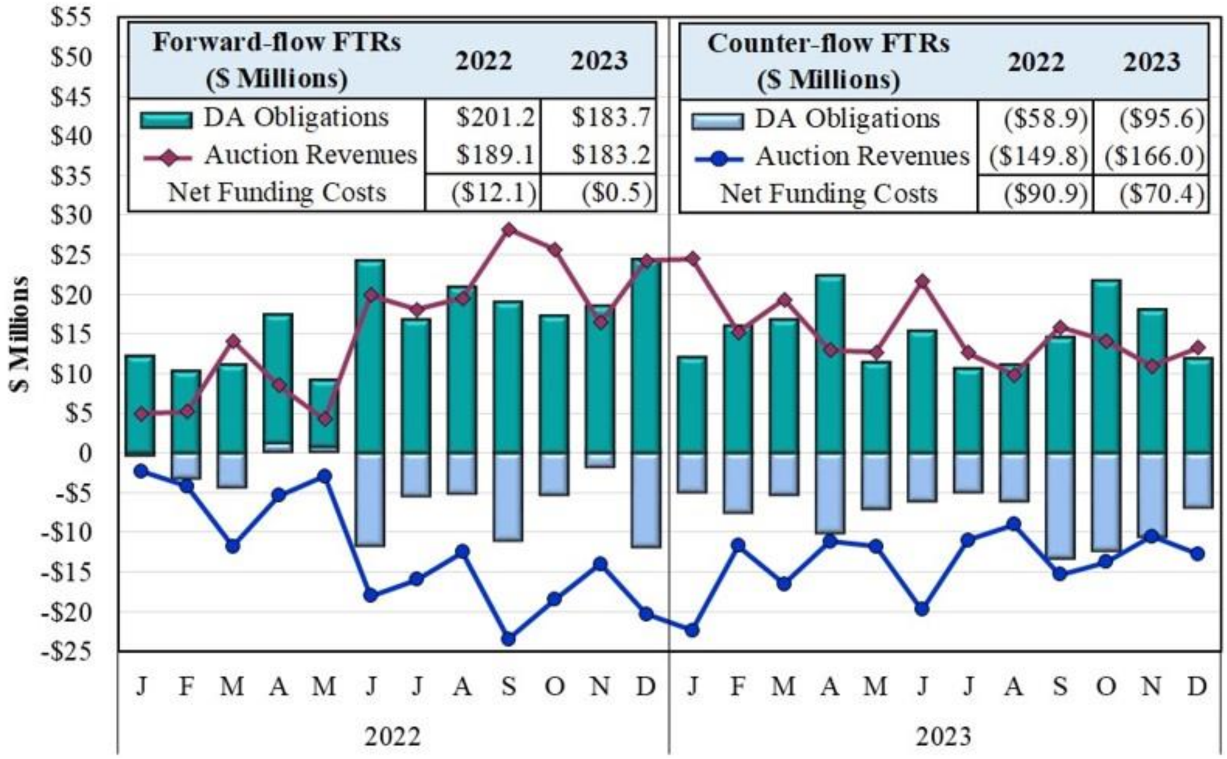


Annual FTR Profitability. Figure 25 shows that FTRs issued through the annual FTR auction were unprofitable overall. Losses are most common in the annual auction because it occurs furthest from the operating timeframe so congestion is more uncertain, and some conversions of AARs to FTRs occur at prices that do not reflect expected congestion.

FTR Profitability in the MPMA and Monthly Auction. Figure 25 shows that the FTRs purchased in the MPMA and prompt month auction continued to be profitable. 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 26 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.

Figure 26: Prompt-Month MPMA FTR Profitability
2022–2023



The analysis shows that the discount in the sale of forward-flow FTRs decreased from six percent in 2022 to less than one percent in 2023, translating to net funding costs (i.e., profits from these FTRs) falling from $12 million to $0.5 million. These results indicate that the market expectations of congestion were relatively accurate on average in the prompt months.

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.[24] Net funding deficits for counter-flow FTRs were significant in 2023, indicating that MISO substantially over-paid for these FTRs compared to the day-ahead congestion value on average. However, the auction revenues for several months, such as April and September through November, 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

24 For example, assume MISO issued 250 MW of FTRs over an interface that now can support only 200 MW of flow. MISO could sell 50 MW of counter-flow FTRs to reduce the FTR obligation to 200 MW.

examine its auction processes to determine whether to establish price-based limits on the sale of forward or counterflow 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 $210 million in valuation change 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 zones and load zones where no ARRs are awarded and no load is settled.

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

MISO's market-to-market (M2M) process under Joint Operating Agreements (JOAs) with neighboring RTOs enables 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 within and outside of MISO decreased overall in 2023:

- Congestion on MISO M2M constraints fell 63 percent from 2022 to total $733 million because of lower gas prices and lower average wind output.
- Congestion on external M2M constraints (those monitored by PJM and SPP) rose by four percent year over year to $136 million.
- An SPP constraint, Charlie-Creek Watford, contributed $61 million in congestion and $37 million in JOA payments over the year. It should be removed from the M2M process because MISO cannot offer relief (as we describe below).

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)
2022–2023

	PJM	SPP	Total
2023	$57	-$87	-$30
2022	$183	-$152	$31

Table 9 shows that net payments generally flowed from PJM to MISO because PJM exceeded its FFEs on MISO's system. Forty-six 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 oscillation 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.

Charlie Creek–Watford Constraint

The Charlie Creek–Watford constraint is an SPP constraint in the Williston load pocket that participates in M2M coordination with MISO. It sits in an ill-defined geographic area where some nearby constraints are in SPP's footprint while others are in MISO. Beginning in April

2023, a crypto currency mine began operation in the SPP footprint and frequently loaded the constraint. While transmission upgrades are planned in the area, little congestion relief is currently available. MISO has requested suspension of M2M coordination of the Charlie Creek–Watford constraint because it is a local issue not intended to be addressed by M2M coordination.

Charlie Creek–Watford contributed approximately $61 million in inefficiently high congestion and $37 million in JOA payments over the year. In addition, SPP has mismanaged the constraint in a way that contributes to MISO customers' financial burden by incorrectly modeling a low FFE for MISO. SPP has refused MISO's request to address the negative impacts of the constraint on MISO customers and exclude it from M2M coordination, and MISO has filed a complaint at the Commission.

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 time needed to test a constraint by removing the first day a constraint was binding.

Table 10: Real-Time Congestion on Constraints Affected by Market-to-Market Issues
2021–2023

Item Description	PJM ($ Millions)			SPP ($ Millions)			Total ($ Millions)		
	2021*	2022*	2023	2021*	2022*	2023	2021*	2022*	2023
Never classified as M2M	$17	$6	$5	$50	$55	$33	$68	$61	$38
M2M Testing Delay	$20	$7	$5	$55	$44	$40	$75	$51	$45
M2M Activation Delay	$2	$1	$0	$34	$6	$1	$36	$7	$2
Total	$39	$14	$10	$139	$105	$74	$179	$119	$84

*We have excluded the Winter Storm Uri days (02/13-02/19/2021) and Winter Storm Elliott days (12/22-12/27/2022).

Historically, the highest congestion impacts occurred on constraints that MISO failed to test. To address this process, MISO implemented a tool to improve its M2M identification and testing procedures. Nonetheless, the value of congestion on SPP constraints that were never tested continued to be significant, so we encourage MISO to evaluate ways to improve its M2M processes and timeliness of the testing process.

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 a M2M constraint when the NMRTO has:

- A generator with a shift factor greater than five percent; or
- Market flows over the MRTO's constraint 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.[25] The

25 Economic relief is categorized as any redispatch relief that could be provided within five minutes time with a shadow price less than or equal to $200.

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.E 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.

Other Key Market-to-Market Improvements

Our evaluation indicates two additional improvements that MISO should pursue that would improve the efficiency and effectiveness of the M2M coordination with SPP and PJM:

- It is often much more efficient for the NMRTO to monitor because it has most of the effective relief capability. We recommend MISO continue working with SPP and PJM to improve the procedures to transfer the monitoring responsibility to the NMRTO.
- MISO has developed software intended to allow the MRTO to control oscillations on constraints where both the MRTO and the NMRTO have fast-ramping resources responding to M2M price signals, but its use has been limited.
- 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.

D. 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. Since 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.

In recent years, TLRs called by IESO have resulted in thousands of MWs of transaction curtailments from PJM to MISO and costly price spikes throughout MISO. There are many other actions that are less costly than curtailing vast quantities of PJM-to-MISO transactions. Unfortunately, the TLR process is indiscriminate and does not facilitate the most efficient relief. Therefore, we continue to recommend that MISO work with both TVA and IESO to develop JOAs that would reduce the costs of this external congestion.

E. 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.[26] 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. We believe that at least 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 within three years.

26 Temperature is one common dynamic factor. In some regions, ratings are more dependent on other factors, such as ambient wind speed and humidity. Ratings used during night-time hours can be adjusted for the absence of solar heating. Our analysis evaluates only ambient temperature impacts.

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.[27] This analysis is described in detail in Section V.D of the Analytic Appendix and summarized in Table 11.

Table 11: Benefits of Ambient-Adjusted and Emergency Ratings
2022–2023

		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2022	**Midwest**	$372.4	$180.87	$553.3	26	16.5%
	South	$7.9	$19.16	$27.0	2	9.4%
	Total	**$380.3**	**$200.0**	**$580.3**	**28**	**15.9%**
2023	**Midwest**	$171.7	$89.80	$261.5	17	16.2%
	South	$1.2	$7.74	$8.9	5	6.7%
	Total	**$172.8**	**$97.5**	**$270.4**	**22**	**15.5%**

Across the past two years, the results show average benefits of 16 percent of the real-time congestion value. The total potential savings in 2022 and 2023 were three-quarters 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 Analytic Appendix details how these estimated benefits in 2023 are distributed in the areas served by transmission owners.

Recommended Improvements to Achieve the AAR Benefits

As MISO plans for compliance with Order 881, effective July 25, 2025, we encourage it to accelerate efforts to implement AARs and Emergency Ratings in real time. We also recommend that MISO enable forecasted ratings in the day-ahead market as soon as practicable.

F. Operator Congestion Management Actions

The increasing penetration of wind and other intermittent resources have created more challenges for MISO managing congestion on the constraints these resources effect. In this section, we discuss key actions that MISO operators have been taking to manage congestion reliably.

27 We used temperature and engineering data to estimate the temperature adjustments. To estimate the effects of using emergency ratings, we assume that the emergency ratings are 10 percent higher than the normal ratings. This is consistent with other facilities for which TOs submit emergency ratings. We then estimated the value of both of these increases based on the shadow prices of the constraints.

Actions Affecting the Dispatch of Resources

MISO operators have increasingly relied on out-of-market dispatch actions to manage congestion, including:

- Manually re-dispatch (MRD) units to force generation to a lower level;
- Capping units' generation to a maximum level (Caps); or
- Modify transmission constraint demand curve (TCDC) values to allow the dispatch model to access more costly relief to manage congestion in real time.

Adjusting the TCDC is usually the preferred action because it allows the dispatch model to optimally manage the flows and sets prices that reflect the marginal cost of congestion. MRDs or Caps are typically only preferred when the dispatch cannot move up and down quickly enough to manage volatile transmission flows. The downside of manually intervening in the dispatch is that the manual action will rarely be optimal, and the manually dispatched generator will frequently require: a) DAMAP payments if they are limited to running uneconomically below its day-ahead schedule to compensate them for buying out of their day-ahead schedules at real-time prices; or b) RTORSGP if they are compelled to run an higher output levels than is economic.

We have encouraged MISO to expand its use of TCDC adjustments in lieu of MRDs or Caps, which MISO made progress on in 2023:

- MRD actions (measured on a plant-day basis) fell by 62 percent from 2022 and the associated DAMAP payments fell 94 percent.
- TCDC actions (measured on a constraint-day basis) increased 45 percent from last year.
- However, the use of Caps and associated DAMAP payments increased substantially in 2023, exceeding the use of MRDs or TCDC adjustments.

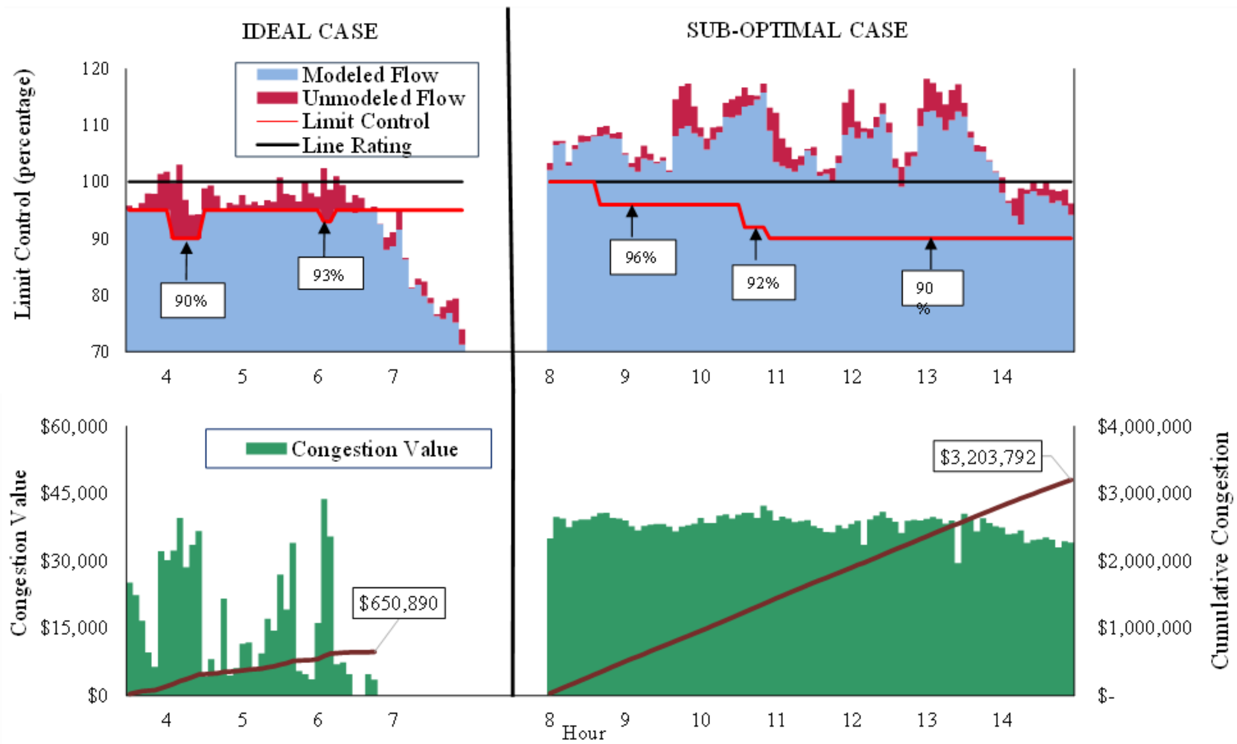
Although the trends in the use of MRDs and TCDC adjustments have been positive, we continue to encourage MISO to minimize the use of Caps.

Manual Transmission Deratings

One of the congestion management actions MISO takes is to apply a "limit control" that reduces the limit modeled in the dispatch by a specified percentage. We have observed an increasing reliance on limit control adjustments over the past three years, which have grown from roughly five to six percent. These deratings should be minimized because their cost can be substantial. We estimated their cost was almost $270 million in 2022 and $125 million in 2023.

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. Generally, this occurs when the limit control values are excessive or are not updated after the deviations fall. To show the difference between ideal use of limit controls and sub-optimal use, Figure 27 illustrates these two cases.

Figure 27: Limit Control Use Case Studies



In the ideal example in the left panel, the unmodeled flow caused an exceedance of the line's normal rating, and operators applied a limit control of 90 percent that caused the dispatch to provide relief and lower the modeled flows on the constraint to make room for the unmodeled flow. In the following intervals, the unmodeled flow fell and the operator then returned the limit control back to its original value. In subsequent intervals, large unmodeled flows occurred and the operator repeated the process, lowering the modeled limit to reduce the modeled flow on the constraint. In this example, the congestion costs are $650,000.

The right panel of Figure 27 illustrates a sub-optimal example of the use of limit control. In this example, the line rating was reduced three separate times when the operator observed model flows exceeding the normal line rating (black line) and the deratings were retained for 14 hours. However, derating a constraint because the modeled flows exceed the limit is not appropriate because it does not result in lower modeled flow. Hence, each of these successive changes provided no incremental benefit. However, excessive transmission deratings can inflate congestion inefficiently. In this case, the congestion exceeded $3 million, although most of this congestion would have occurred even without the deratings as the constraint was in violation.

Based on our monitoring of MISO's use of the limit control, we find that it is relatively inconsistent. This may be attributable to the lack of an operating procedure to guide how the limit control parameter is set. Additionally, the logging of the reasons for the limit control adjustments is generally limited. Hence, we recommend MISO develop a clear limit control procedure to guide its determination and institute logging to ensure the procedure is followed.

G. 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 2023 despite extremely low natural gas prices. Hence, improvements aimed at the efficiency of its congestion management can deliver sizable savings. Many of these improvements we discussed 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 an economic decommitment 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, 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, 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 they were contributing to 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.

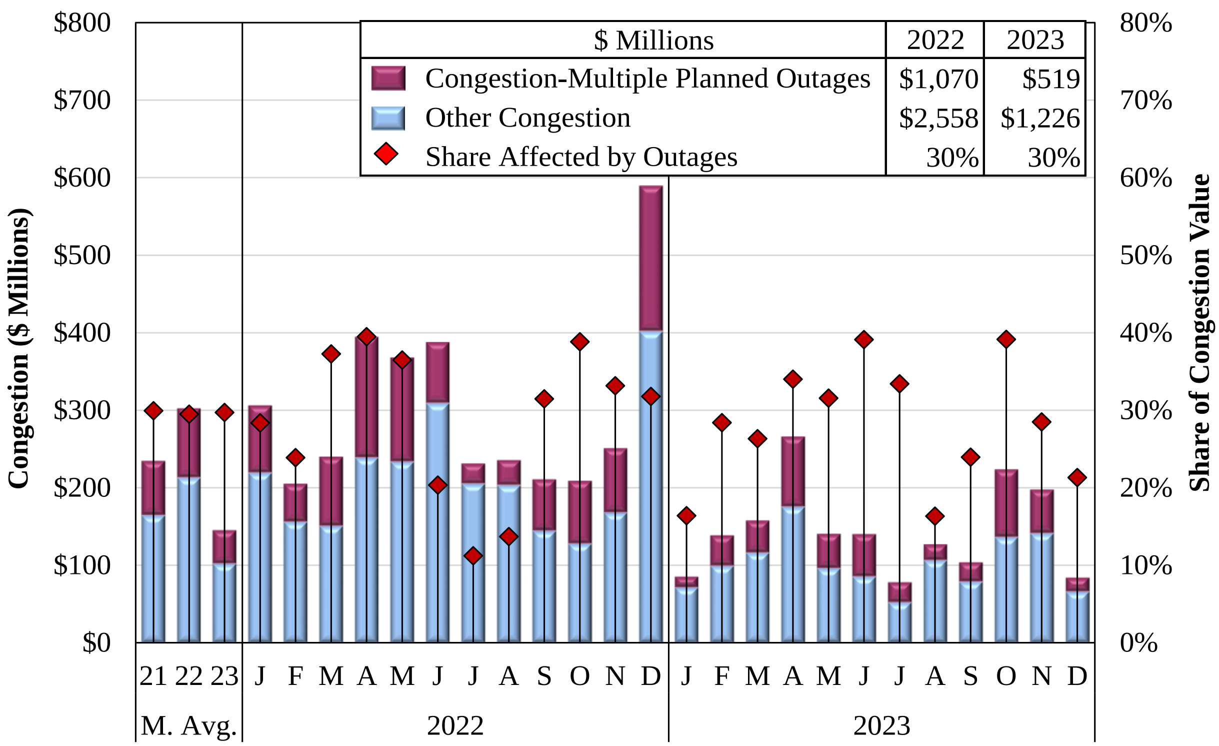
Coordinating Outages that Cause Congestion

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 28 summarizes the effects of uncoordinated planned outages on congestion by showing the portion of the real-time congestion value for 2022 and 2023 that occurred on internal constraints that were substantially affected (at least 10 percent of the constraints' flows) by two or more planned outages.

Figure 28 shows that 30 percent of the total real-time congestion on MISO's internal constraints in 2023 ($0.5 billion) was attributable to multiple planned generation outages. In five months of the year, more than one-third of the monthly congestion was associated with outages. Figure 28 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.

Figure 28: Congestion Affected by Multiple Planned Generation Outages
2022–2023



$ Millions	2022	2023
Congestion-Multiple Planned Outages	$1,070	$519
Other Congestion	$2,558	$1,226
Share Affected by Outages	30%	30%

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 2023, 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.

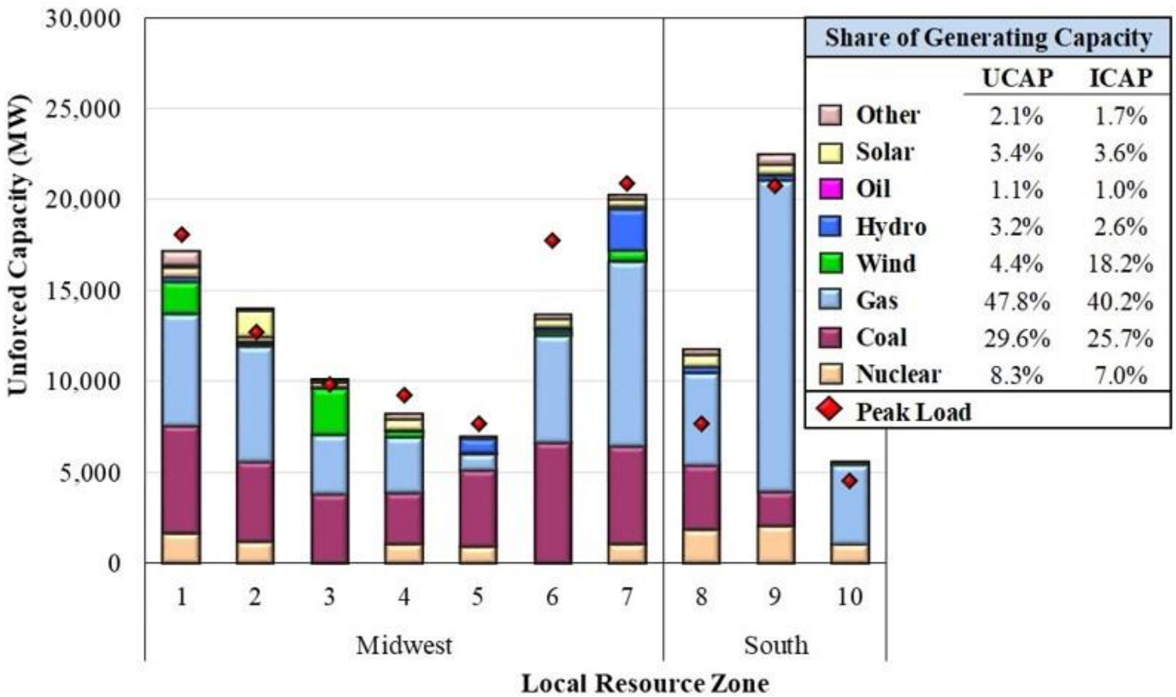
VI. Resource Adequacy

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 29 shows MISO's Unforced Capacity (UCAP) at the end of 2023 by Local Resource Zone (LRZ) and fuel type, along with the coincident peak load in each zone.[28] UCAP values account for forced outages and intermittency. Therefore, UCAP values for wind units are much lower than Installed Capacity (ICAP) values, as shown in the inset table.

Figure 29: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2023



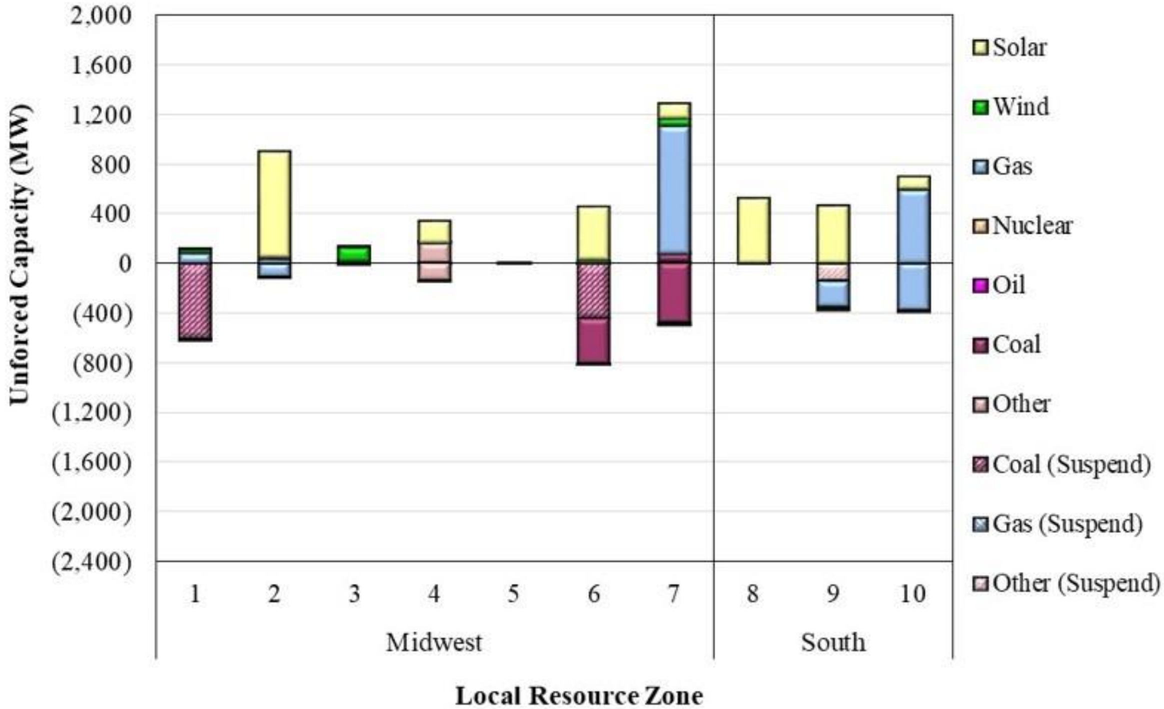
This figure shows that gas-fired resources account for a larger share of MISO's capacity than any other capacity type, including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from MISO South to the MISO Midwest when natural gas prices are low and outages are minimal.

28 UCAP was based on data from the MISO PRA for the summer season of the 2023-2024 Planning Year and excludes LMR capacity.

B. Changes in Capacity Levels

Capacity levels have been falling in recent years because of accelerating retirements of baseload resources, which are being partially replaced with renewable resources. Figure 30 shows the capacity additions (positive values) and losses during 2023. The hatched bar indicates newly suspended resources, which rarely return to service. 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 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. Figure 30 does not show retirements for resources in 2023 that were suspended in 2022.

Figure 30: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone in 2023



Capacity Losses

In 2023, 2.8 GW of resources retired or suspended operations in MISO, consisting of primarily coal and gas steam resources. Some of the suspended unforced capacity is under consideration for partial replacement and could return as new generation (primarily solar and battery) in the next three years.[29] These retirements should 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

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

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 two resources in MISO are designated SSR.

New Additions

In 2023, 5 GW of unforced new capacity entered MISO. A 1 GW natural gas-fired combined-cycle resource entered MISO in the Midwest and a 600 MW combined-cycle entered in the South. Approximately 2.6 GW (UCAP) of solar resources entered in 2023, roughly split between the Midwest and South, which more than doubled MISO's existing solar capacity. Approximately 700 MW (nameplate) of wind entered, although their total summer UCAP value is only 240 MW because they provide less reliability than conventional resources.

C. Planning Reserve Margins and Summer 2024 Readiness

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted summer peak loads in 2024. Since assumptions regarding the supply availability and load can substantially change the planning reserve margins, Table 12 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 2024 *Summer Readiness Workshop*, including the 1,900 MW transfer limit assumption between MISO South and Midwest.[30] 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, 2024.

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.

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.

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

Table 12: Summer 2024 Planning Reserve Margins

	Base Scenario	Alternative IMM Scenarios* Realistic Scenario	Realistic <=2HR	High Temperature Cases Realistic Scenario	High Temperature Cases Realistic <=2HR
Load					
Base Case	122,600	122,600	122,600	122,600	122,600
High Load Increase	-	-	-	6,690	6,690
Total Load (MW)	122,578	122,578	122,578	129,290	129,290
Generation					
Internal Generation Excluding Exports	132,120	132,120	132,120	132,120	132,120
BTM Generation	4,331	4,331	3,336	4,331	3,336
Unforced Outages and Derates**	(43)	(12,458)	(12,458)	(20,058)	(20,058)
Adjustment due to Transfer Limit	(1,417)	-	-	-	-
Total Generation (MW)	134,991	123,993	122,998	116,393	115,398
Imports and Demand Response* **					
Demand Response (ICAP)	8,109	6,082	3,080	6,082	3,080
Firm Capacity Imports	4,335	4,335	4,335	4,335	4,335
Margin (MW)	24,857	11,832	7,836	(2,480)	(6,477)
Margin (%)	**20.3%**	**9.7%**	**6.4%**	**-1.9%**	**-5.0%**
Expected Capacity Uses and Additions					
Expected Forced Outages****	(6,823)	(6,702)	(6,702)	(6,702)	(6,702)
Non-Firm Net Imports in Emergencies	4,260	4,260	4,260	4,260	4,260
Expected Margin (MW)	22,295	9,390	5,394	(4,922)	(8,919)
Expected Margin (%)	**18.2%**	**7.7%**	**4.4%**	**-3.8%**	**-6.9%**

* Assumes 75% response from DR.
** Base scenario shows approved planned outages for summer 2024. Realistic cases use historical averages during peak summer hours. High temp. cases are based upon MISO's 2024 Summer Assessment.
*** Cleared amounts for the Summer Season of the 2024/2025 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 20.3 percent – which exceeds the summer installed capacity Planning Reserve Margin Requirement (PRMR) of 17.7 percent. In the realistic scenario, the planning reserve margin falls to 9.7 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.[31] This is conservative because the import levels would likely rise to much higher levels in response to shortage pricing in MISO.

31 The additional imports are consistent with the non-firm external support assumptions in MISO's 2024-2025 LOLE study.

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 12 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 6.4 and further to 4.4 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.[32] 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 -3.8 to -6.9 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 9 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 2024 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 replaced by renewable resources. Therefore, it remains important for the capacity market and shortage pricing to provide efficient economic signals to maintain adequate resources.

We conducted a similar analysis for Winter 2024/25 based on the 50/50 winter forecasted peak load and present those results in Section VI.C of the Analytic Appendix.

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

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

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 2023–2024 Planning Year

MISO substantially reformed 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.[33] These changes addressed two recommendations that we have made in recent *State of the Market* reports.[34] This new construct was introduced in the 2023–24 PRA held in April 2023. The results are summarized in Table 13.

Table 13: 2023–24 Planning Resource Auction Results

<table>
<tr><th rowspan="2">Season</th><th rowspan="2">Capacity Procured</th><th rowspan="2">Offered Not Cleared</th><th rowspan="2">LOLE Target</th><th colspan="2">Prices ($/MW-Day)</th></tr>
<tr><th>Rest of Market</th><th>Zone 9 (LA,TX)</th></tr>
<tr><td>Summer 23</td><td>132,891</td><td>6,483</td><td>0.10</td><td colspan="2">$10.00</td></tr>
<tr><td>Fall 23</td><td>125,795</td><td>10,587</td><td>0.01</td><td>$15.00</td><td>$59.21</td></tr>
<tr><td>Winter 23/24</td><td>128,104</td><td>11,378</td><td>0.01</td><td>$2.00</td><td>$18.88</td></tr>
<tr><td>Spring 24</td><td>124,389</td><td>10,049</td><td>0.01</td><td colspan="2">$10.00</td></tr>
<tr><td>PRA Year</td><td>127,795</td><td>9,624</td><td>0.13</td><td>$9.25</td><td>$24.52</td></tr>
</table>

Across the four seasons, market clearing prices averaged $9.25 per MW-day, with a low of $2 per MW-day in the winter, a high of $15 per MW-day in the fall, and $10 per MW-day in the summer and spring. Prices separated in Zone 9 in the fall and winter with prices clearing at $59.21 and $18.88 per MW-day, respectively, because of tight supply in this zone. Nonetheless, these prices were much lower than the prices that were set at CONE of $237 per MW-day in the Midwest (Zones 1 to 7) in the 2022–23 PRA.

This collapse in the prices was the result of a 6 GW increase in net accredited capacity in the summer season of the 2023–2024 planning year and the vertical demand curves utilized in the market. The following factors contributed to this increase in net capacity in the Midwest:

- 2.1 GW decrease in PRMR from lower coincident peak forecasts and a lower PRM;
- 1.1 GW addition of new thermal capacity that more than offset 0.9 GW of retirements;
- 250 MW increase in accreditation of Midwest resources in the transition to SAC;
- 640 MW of new solar resources;

33 Docket No. ER22-495-000.

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

- 1.2 GW of additional wind: 450 MW of new wind resources and a 740 MW increase in existing wind capacity from procuring firm transmission to be deliverable; and
- 1.1 GW increase in LMRs, mostly from External Resources and demand response.

Most of the increase in net capacity was associated with reduced requirements and an increase in voluntary participation (e.g., LMRs and more converted wind deliverability). The change in requirements year-to-year is difficult to predict, but the change in participation was likely a reaction to the high Midwest shortage pricing in the 2022–23 planning year. While there was a net gain in thermal capacity in the 2023–24 PRA, we expect continued retirements of aging coal and gas resources in future years.[35] Rapid increases in solar and wind resources will also continue, but these resources are limited in their ability to satisfy MISO's reliability needs.

Unfortunately, MISO's capacity market has not been designed to send efficient price signals to spur the development of new dispatchable resources. Addressing this inefficiency requires MISO to correct the representation of demand by adopting a reliability-based demand curve (RBDC). MISO has proposed an RBDC that would have raised summer capacity prices by five-fold to more than $50 per MW-day.

PRA Results for the 2024–2025 Planning Year

MISO held its second seasonal capacity auction in March 2024, producing the following results:

Table 14: 2024–25 Planning Resource Auction Results

Season	Capacity Procured	Offered Not Cleared	LOLE Target	Prices ($/MW-Day)	
				Rest of Market	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	0.13	$19.96	$367.59

Across the four seasons, market clearing prices average 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 is 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 derives 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.

35 Some coal resources were scheduled to retire in summer 2023 but were delayed after the Midwest shortage in the prior PRA: 300 MWs delayed retiring to summer 2024 and 1.2 GW delayed retiring to summer 2025.

Unfortunately, these prices do not reflect true reliability risk in these zones. For example, Zone 5's average price for the planning year is two percent above annual CONE, but the probability of losing load is substantially below MISO's 1-in-10 year reliability standard. MISO's RBDC filing does not alter this vertical CONE-based pricing of LCRs. To address this concern, we recommend 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 from recent winter storms. This has largely been due to the growth in wind resources, even though having high levels of wind output during winter storms is not guaranteed.

Discussion of Other Issues Affecting the Performance of the PRA

Switchable External Resources. We have raised concerns with MISO about the use of controllable export adjustments to LCRs. This has been a particularly large issue in Zone 9 associated with 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 in emergencies even though it has not been available in any emergency in recent years. Correcting this assumption in Zone 9 would have increased the LCR by 0.5 GW and led to price separation in the spring season, raising the clearing price to $60 per MW-day.

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 should produce net revenue sufficient to support new investment at times when existing resources are not adequate to meet the system's needs. Figure 31 and Figure 32 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 31: Net Revenue Analysis
Midwest Region, 2021–2023

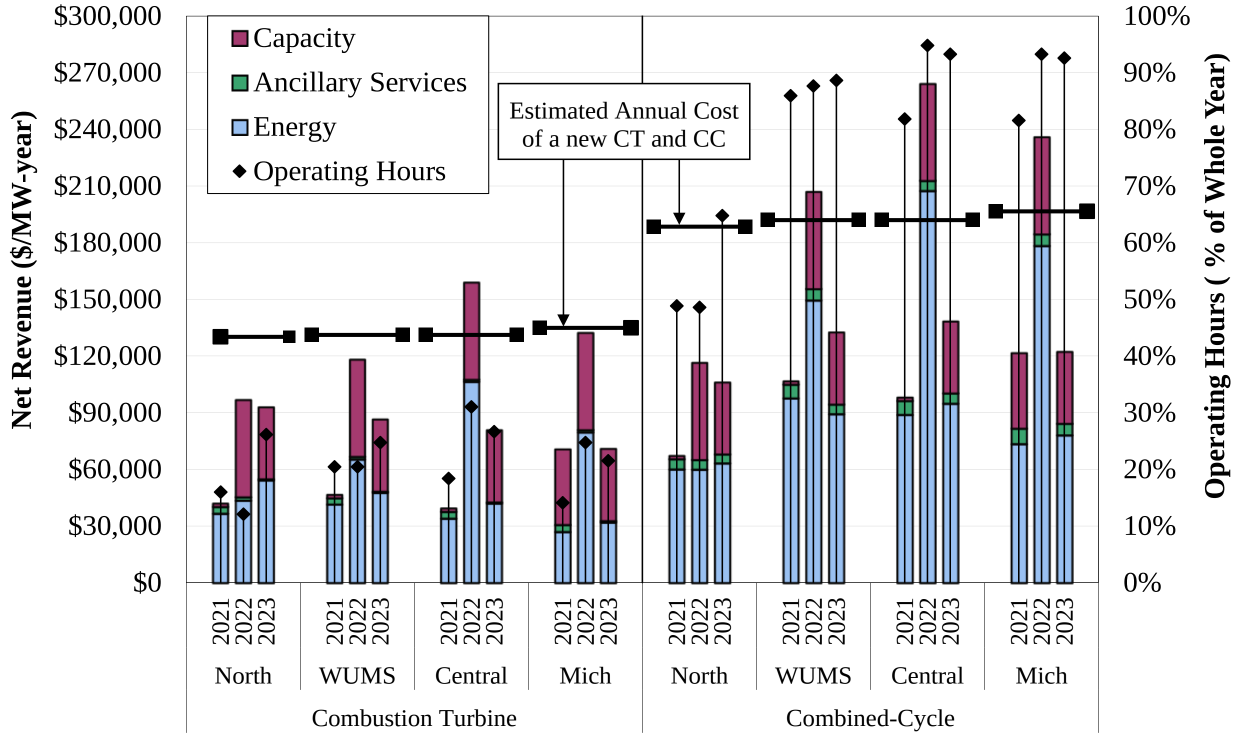
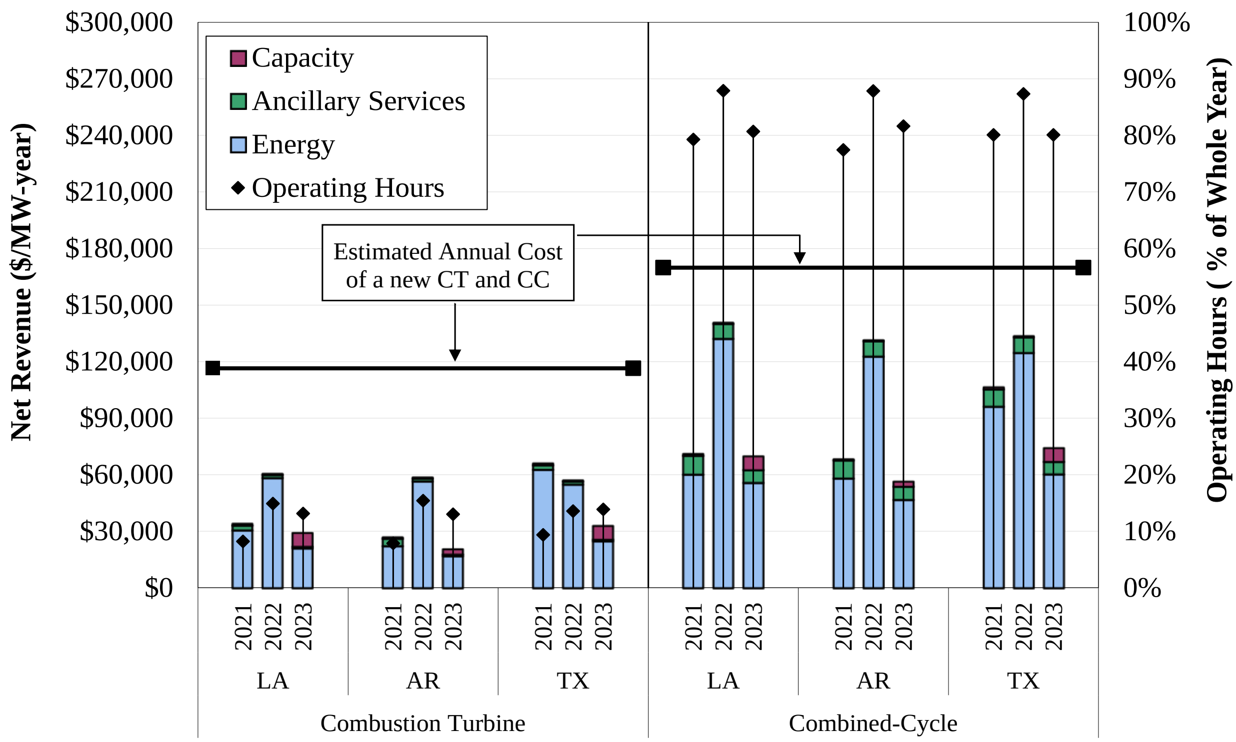


Figure 32: Net Revenue Analysis
South Region, 2021–2023



These figures show that net revenues fell in all regions in 2023, partly because lower natural gas prices contributed to lower energy and ancillary services prices throughout MISO, and partly because MISO experienced a period of sustained high prices during Winter Storm Elliott in December 2022 that contributed to the higher net revenues in 2022.

Overall, MISO's economic signals continue to be undermined by capacity market design issues, including a poor representation of demand as a single quantity value (i.e., a vertical demand curve). MISO has recently proposed a reliability-based demand curve in the Planning Resource Auctions that will address this concern and will raise capacity prices to much more efficient levels and allow 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):[36]

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

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

(1) It allows a resource on outage the entire season (over 90 days) to be profitably sold; and

(2) It creates incentives to schedule long-term planned outages that straddle seasons to avoid the CRNCC, which could degrade reliability.

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

We recommend that MISO reform this penalty structure to address these incentive concerns.

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 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 recommend that MISO develop a reasonable methodology for accrediting emergency-only resources in the PRA.

MISO filed Tariff changes in that restrict the use of emergency commitment status in energy offers that became effective in June 2023.[37] MISO intends to make a follow-up accreditation filing to account for restricted availability of AME and allow operators to call on AME resources with more than two-hour lead times in advance of emergency declarations but has yet to come up with a final proposal.

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.

[37] Docket No. ER23-1523-000.

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 of 20 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. MISO remained a substantial net importer in 2023:

- Day-ahead and real-time hourly net scheduled interchange (NSI) averaged 3.9 and 4.5 GW, respectively (positive NSI values reflect net imports).
- MISO's largest and most actively scheduled interface is the PJM interface. MISO was a net importer from PJM in 2023.
  - Hourly real-time imports from PJM averaged 3.1 GW, up 38 percent from 2022.
  - 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 2023, nearly 60 percent of the transactions with PJM and over 65 percent of the transactions with SPP were scheduled in the profitable direction. Many hours still exhibit large price differences that offer substantial production cost savings.

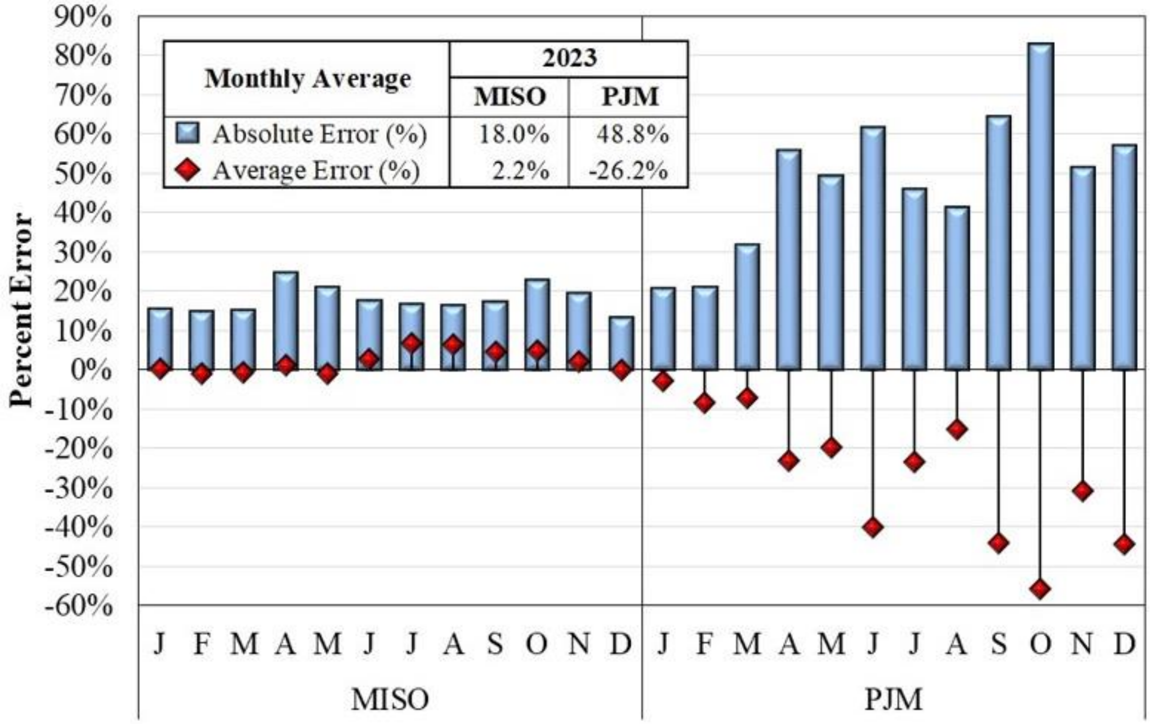
B. Coordinated Transaction Scheduling

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 2023, the hourly average quantity of CTS transactions offered and cleared remained extremely low at 60 MW and 30 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 33, we show the forecasting errors by month in both average and absolute average terms for MISO and PJM.

Figure 33: MISO and PJM CTS Forecast Errors
2023



This analysis shows significant inaccuracies in the forecast prices used for CTS, particularly in PJM where the forecasts are both large and biased. In 2023, the average difference between PJM's real-time LMPs and its forecast prices for the interface was -26 percent, and the average of the absolute difference was 49 percent.[38] For the same period, the average difference between

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

MISO's real-time LMPs and its forecast prices for the interface was two percent, and the average of the absolute difference was 18 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 2023 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 price 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.

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 15 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 $100 million in production cost savings versus only $7 million under the current process. Although adjustments would have occurred in 50 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 $30 million in production cost savings with a similar level of adjustments.

Table 15: CTS with Five-Minute Clearing Versus Current CTS
2023

	Percent of Intervals Adjusted	Production Cost Savings	Profits	Percent Unprofitable
PJM				
Current CTS	0.9%	$7,234,577	$237,989	18.3%
5-Minute CTS	49.2%	$102,950,448	$43,041,522	9.8%
SPP				
5-Minute CTS	25.3%	$34,382,814	$20,458,366	19.0%

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 $40 million from the cleared CTS transactions with PJM compared to profits in 2023 of just $238,000 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 $20 million. Hence, using the most recent five-minute prices is a substantial improvement and leads to more efficient CTS adjustments. We recommend MISO pursue this form of CTS process with both PJM and SPP.

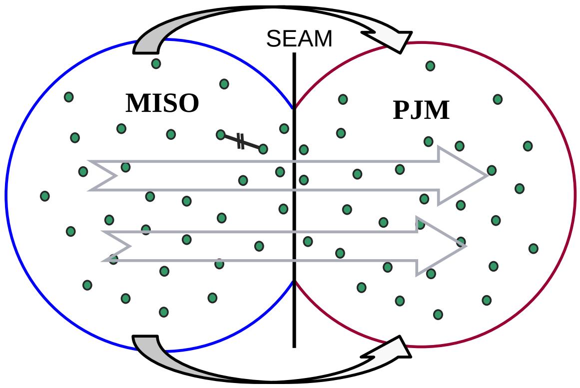
C. Interface Pricing and External Transactions

Each RTO posts its own interface price used to settle with physical schedulers wishing 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.

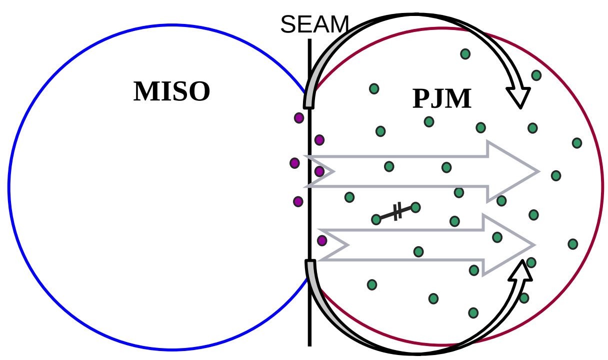
Establishing efficient interface prices would be simple in the absence of transmission congestion and losses—each RTO would simply post the interface price as the cost of the marginal resource on its system (the system marginal price, or "SMP"). Participants would respond by scheduling power from the 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.

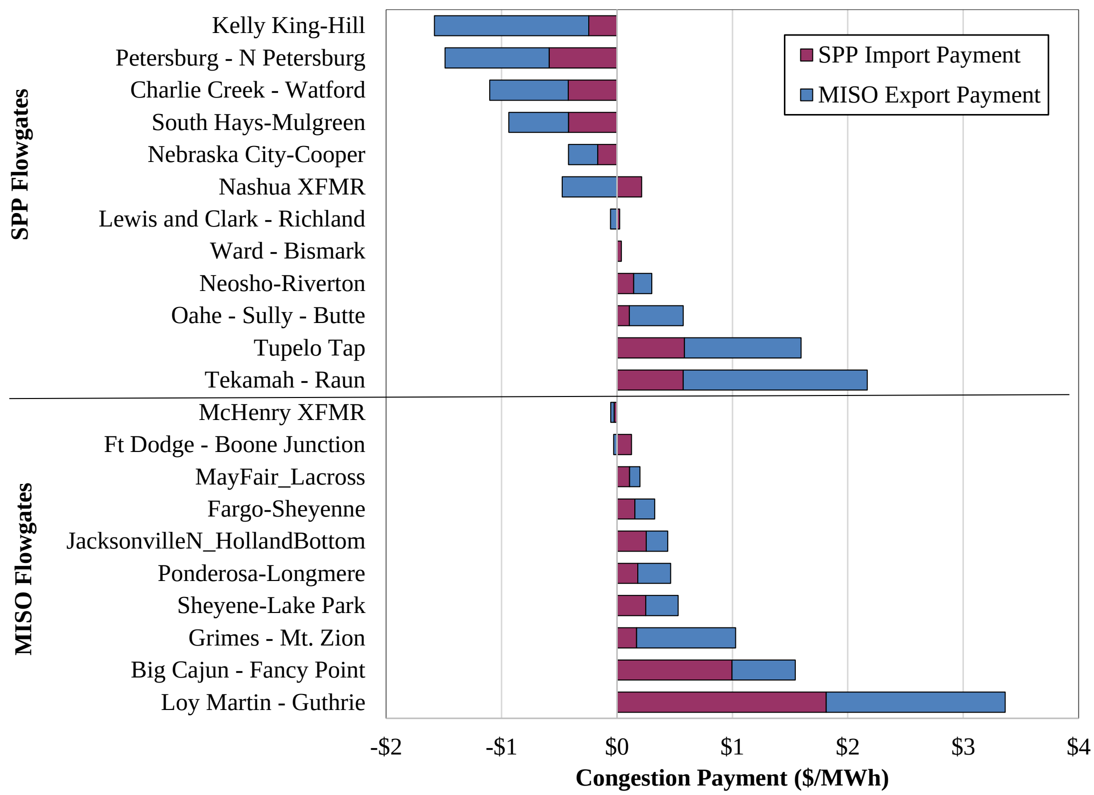


We have identified the location of MISO's marginal generators and confirmed that they are distributed *throughout* MISO, so we are concerned that the common interface definition sets inefficient interface prices. Our interface pricing studies show that in aggregate, the common interface has led to larger average errors and 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. In other words, when a M2M constraint binds, both RTOs price and settle with external transactions based on their respective estimates of the entire congestion effects of the transaction. Since both RTOs have relatively good models, their estimates are typically very 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 individual M2M constraints. These coordinated constraints had congestion value exceeding one million dollars between June 2018 and May 2019. Figure 34 shows the congestion component calculated by both SPP and MISO for each constraint, separately showing MISO constraints and SPP constraints. The congestion payments are displayed as the settlement of an export transaction from MISO to SPP. A negative value indicates that the participant would be charged the corresponding amount; whereas a positive value indicates that the participant would be paid for congestion relief.

Figure 34: Constraint-Specific Interface Congestion Prices



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 participants to schedule imports and exports when M2M constraints are binding significantly. It also results in additional costs for the RTOs. When SPP makes a payment for an external 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 ($40 per MWh), MISO would receive some relief for having made the payment, while SPP as the NMRTO would receive no credit and would generally recover the costs of its payment 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 and MISO re-dispatches its generation to meet its TLR flow obligation. 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 2023. 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 (588) but very high in some local areas, such as WUMS (4432) and the South Region (3696), 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". A supplier is pivotal when its resources are necessary to satisfy load or to manage a constraint. Our regional pivotal supplier analysis indicates that the frequency with which a supplier is pivotal rises sharply with load. This is typical in electricity markets because electricity cannot be economically stored. Hence, when load increases, excess capacity will fall, and the resources of large suppliers may be required to meet load.

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, 64 percent of the active BCA constraints had at least one pivotal supplier.
- Over 90 percent of the binding constraints into both the MISO South NCAs and the Midwest NCAs had at least one pivotal supplier.

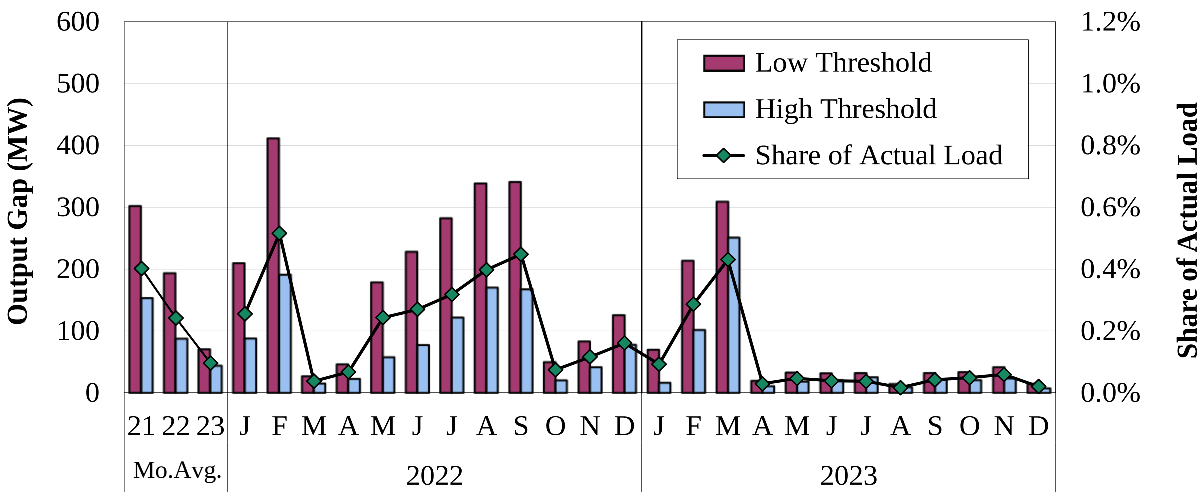
Overall, these results indicate that local market power persists, with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

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 3.0 percent in 2023. The mark-up was very small, indicating the markets were highly competitive overall.

Figure 35 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 35: Economic Withholding – Output Gap Analysis
2022–2023



Low Threshold Results by Unit Status (MW)

	21	22	23	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	38	95	55	22	24	17	20	103	118	184	238	256	27	47	82	29	170	301	11	25	22	23	6	25	17	27	4
Online	264	99	15	188	387	11	27	75	110	98	100	84	23	36	43	41	43	8	9	8	10	9	8	7	17	15	11

High Threshold Results by Unit Status (MW)

	21	22	23	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	28	59	40	21	20	12	17	51	67	110	156	151	12	36	59	12	94	247	6	13	15	21	6	19	16	21	4
Online	125	28	5	67	171	4	6	7	10	12	14	16	8	6	19	5	7	4	5	6	5	5	4	3	5	3	3

The figure shows that the average monthly output gap level was 0.1 percent of load in 2023, which is effectively *de minimis* and lower than in 2022. 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. In contrast, 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 2023 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 2023. 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 decreased in 2023, affecting less than one percent of real-time market hours across 28 days, down from 40 in 2022 (excluding six additional days around Winter Storm Elliott when offer-capping was applied). 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 six day-ahead market days in 2023, down from 14 in 2022 (again excluding the additional six days around Winter Storm Elliott).

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 day-ahead and real-time RSG mitigation payments were 78 and 69 percent lower, respectively, in 2023 compared to 2022. While lower natural gas prices were a primary driver, MISO made substantially fewer real-time commitments overall in 2023 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;
- Least-cost resource adequacy in the long term;
- Reductions in price volatility and other market costs; and
- Mitigation of market power.

Additionally, price-responsive demand has the potential to enhance wholesale market efficiency. 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. Hence, it is important to provide efficient incentives for DR resources and to integrate them into the MISO markets in a manner that promotes efficient pricing and other market outcomes. In this section, we discuss the current level of participation of DR and energy efficiency resources (EE) and identify some significant concerns that have arisen related to MISO's approach to incorporating these demand resources in the market as supply resources.

A. Demand Response Participation in MISO

Table 16 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:[39]

- Load-Modifying Resources (LMRs) that are capacity resources that are 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 16, MISO had nearly 12.7 GW of DR capability available in 2023, over 400 MW more than in 2022. Energy Efficiency (EE) participation in the PRA has remained very low after the 2020–21 auction, as discussed below.

39 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 16: Demand Response Capability in MISO and Neighboring RTOs
2021–2023

		2021	2022	2023
MISO[1]		**12,197**	**12,261**	**12,668**
	LMR-BTMG	4,068	4,169	4,129
	LMR-DR	7,152	7,543	7,695
	LMR-EE	0	0	5
	DRR Type I	711	582	521
	DRR Type II	115	127	79
	Total Cross-Registered as LMR	*476*	*279*	*92*
	Emergency DR	785	456	883
	Total Cross-Registered as LMR	*158*	*337*	*552*
NYISO[2]		**1,170**	**1,234**	**1,294**
	Special Case Resources - Capacity	1,168	1,231	1,282
	Emergency DR	2	3	12
	Day-Ahead DRP	0	0	0
ISO-NE[3]		**3,934**	**4,076**	**3,798**
	Active Demand Capacity Resources	511	466	438
	Passive Demand Resources	3,423	3,610	3,360

* All units are MW.

1 Registered as of July for 2023, December for 2021 and 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 2023. Source: ISO-NE Monthly Market Reports.

MISO's demand response capability constitutes around ten percent of peak load, which is a larger portion than in NYISO but slightly less than in ISO-NE. It exhibits varying degrees of responsiveness to prevailing system conditions. The first and largest category of DR (accounting for over 90 percent of MISO's total DR) is LMRs. These capacity resources are interruptible load developed under regulated utility programs and behind-the-meter-generation. A second category is Demand Response Resources (DRRs) that can participate in MISO's capacity, energy, and ancillary services markets and are of two types, as we explain below. A third category is Emergency Demand Response (EDR). Resources may cross-register as LMRs and DRRs or EDRs, and in the table we indicate the amount of capacity that was cross-registered.

LMRs

LMRs are planning resources and thus have an obligation to curtail as instructed 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 residential, small commercial, and industrial customers. They also include behind-the-meter generation (BTMG). These resources do not submit an economic offer price, 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 16, 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 16 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.[40]
- 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 2023. 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.

Emergency DRs

The third category of DR is Emergency Demand Response (EDR), which totaled 883 MW in 2023, almost double the amount that was registered in 2022. 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

40 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.

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 12 hours and is available during the summer months. As part of the RAN initiatives, FERC has approved Tariff changes that reduce the allowable lead time for qualifying LMRs to six hours and accredits resources based on the availability throughout the planning year. These changes began in the 2022–23 planning year and phase in across multiple planning years to allow participants to modify existing contracts and replace affected capacity.[41]

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. 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. 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. 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

41 Beginning in the 2022–23 PRA, LMRs that register with six hours or less notification time and can provide curtailments at least ten times per year are able to fully qualify as capacity resources, and LMRs with longer registered lead times and fewer curtailments have proportionally less capacity.

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, it is essential 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. We have recommended potential improvements to help achieve these objectives and address opportunities for manipulation, the most important of which is to establish a price floor that is significantly higher than typical LMPs. If a participant does not wish to consume at expected real-time prices, it should simply not consume, rather than offering curtailments as a price-taker. There is no reasonable basis to pay for curtailments offered at prices below expected real-time prices. Eliminating the ability to submit price-taking curtailment offers would virtually eliminate both strategies described above.

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.

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 17 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 2023–24 PRA, a small amount of EE participated in and cleared MISO's capacity auction.

Table 17: Growth of Energy Efficiency in MISO

Planning Year	Enrolled Qty	Net Sales	Offer MW	Cleared/FRAP
2017/18	98	0	98	98
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*	4.5	0	4.5	4.5

*Average of four seasons.

We continue to recommend MISO revise its Tariff to strengthen the requirements and validation processes to ensure that only legitimate EE resources are qualified in the future. Although making these Tariff improvements should be MISO's focus in the near-term, we still 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. In the alternative, MISO should develop and file the Tariff improvements described above.

X. RECOMMENDATIONS

Although MISO's markets continued to perform competitively and efficiently in 2023 overall, we recommend a number of improvements in MISO's market design and operating procedures. These thirty-six recommendations are organized by the aspects of the market that they affect:

- Energy and Operating Reserve Markets and Pricing: 8 total, 2 new
- Transmission Congestion: 9 total, 2 new
- Market and System Operations: 11 total, 1 new
- Resource Adequacy and Planning: 8 total, 1 new

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 addressed one of our past recommendations since our last report. We discuss recommendations that have been addressed at the end of this section. For any recurring recommendations, we include a discussion of the progress MISO has made to date and 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.

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: This is a new recommendation.

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: This is a new recommendation.

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 price model to determine when they should set prices during emergency conditions.

Status: MISO has agreed on the problem and MISO has indicated that further study and prototyping of potential software. MISO indicated the software enhancements needed for its evaluation are planned to be available in 2024. This issue is included in MISO's 5-year plan.

Next Steps: MISO should complete its study and prototyping of software solutions.

2021-5: Modify the Tariff to improve rules related to demand participation in energy 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.[42] Some cases have been due to manipulative conduct of the market participants, while some is 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 recommend that MISO work with us to identify and implement these changes.

Status: MISO agrees with these issues and is actively evaluating this recommendation as part of its comprehensive investigation of demand response participation in all MISO markets. MISO believes it is appropriate to revisit the measurement and verification protocols codified in Attachment TT of the Tariff.

Next Steps: MISO plans to review best practices in measuring and validating demand response and to investigate and frame the issue and evaluate any next steps, including an evaluation of requirements of FERC Order 2222 on DERs. MISO indicates it will also consider filing limited modifications, additional requirements, and clarifications to Tariff rules identified by the IMM to address gaming and manipulation vulnerabilities in a potential tariff filing in early 2024.

[42] Order approving stipulation and consent agreement, FERC Docket IN24-3-000, January 4, 2024.

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. However, MISO believes enhancements to its Ramp and Short-Term Reserve products, which are underway, will 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. This recommendation is ranked as a medium priority.

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 the design and implementation of it.

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.

MISO's current ORDC does not reflect the reliability value of reserves, overstating the reliability risks for small, transient shortages and understating them for deep shortages. Additionally, PJM's pay-for-performance rules price modest shortages as high as $6,000 per MWh (sum of the shortage pricing and capacity performance settlement), which will lead to inefficient imports and exports when both markets are tight.

Hence, we recommend MISO reform its ORDC by updating its VOLL assumption and determine the slope of the ORDC based on how capacity levels affect the probability of losing load. We have estimated that a reasonable VOLL for MISO would exceed $30,000 per MWh. Although the ORDC should be based on this VOLL, it would be reasonable to cap the ORDC at a lower price level for deep shortages, such as $10,000 per MWh. Almost all of MISO's shortages are likely to be in ranges that would establish shortage prices between $100 and $2,000 per MWh.

<u>Status:</u> MISO agrees with the recommendation and is working to develop and implement a solution. This item is currently classified as Active and a high priority by MISO. Stakeholder discussions began in the second half of 2023 and MISO anticipates filing proposed enhancements with FERC in 2024.

<u>Next Steps:</u> This recommendation should be one of MISO's highest priorities since it is critical for achieving the goals of the Reliability Imperative and requires no substantial additional resources. Hence, MISO should complete its discussions with stakeholders and file proposed enhancements with FERC in 2024.

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.

<u>Status</u>: This recommendation was originally made in our *2012 State of the Market Report* and there was no progress or change in Status in 2022. 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 Market Systems Enhancement.

Next Steps: MISO should develop the work plan necessary to modify its interface prices as part of of its Market Systems Enhancement.

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 that 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: This recommendation was originally proposed in our *2012 State of the Market Report*. MISO originally agreed with this recommendation, but 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 Market System Enhancement, and it is deferred beyond the 5-year action plan. MISO has mapped this to issue IR005 in the MISO Dashboard. The IMM continues to encourage MISO to reconsider this recommendation.

B. Transmission Congestion

Efficient energy pricing in the real-time market is essential. Even though a very small share (one to two percent) of the energy produced and consumed in MISO is settled through the real-time market, real-time spot market prices affect the outcomes and prices in all other markets. For example, prices in the day-ahead market, where most of the energy is settled, should reflect the expected prices in the real-time market. Similarly, forward prices will be determined by expectations of the level and volatility of prices in the real-time market. Therefore, one of the highest market priorities is to produce real-time prices that accurately reflect supply, demand, and network conditions. This is the objective of the recommendations in this subsection.

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 appropriate and economic.

Status: This is a new recommendation.

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.

Status: This is a new recommendation.

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 that would 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's initial response indicated agreement with the problem and MISO has been discussing the recommendation with the IMM. MISO is developing more comprehensive changes to the ORDC, VOLL (Value of Loss Load) (recommendation 2016-1) and TCDCs. Stakeholder discussions began in the second half of 2023, and MISO anticipates filing proposed enhancements with FERC in 2024.

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

We recommend MISO develop resources and processes to analyze and identify economic reconfiguration options for managing congestion in coordination with the TOs. Today, transmission congestion is 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). Today, this is widely 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 our *2021 Annual State of the Market Report*, we presented an analysis of one constraint that generated over $57 million in congestion during the summer quarter. The constraint primarily limits the output of wind resources in the North region. The constraint has a reconfiguration option that reduces the congestion in that path by more than two-thirds and substantially reduces wind curtailments when used. Unfortunately, it is rarely used because the congestion on the constraint rarely raises reliability concerns. This constraint serves as an instructive case study showing the potential for substantially reducing congestion costs and wind resource curtailments by deploying reconfiguration options economically as a regular congestion management action.

Hence, we recommended MISO work with the transmission owners to develop tools and processes to identify economic reconfiguration options along with the criteria to be used to deploy them. The criteria would ensure that reconfiguration options are not implemented when they would generate adverse reliability effects elsewhere on the system. Studying and identifying such options and criteria in advance for MISO's most congested paths will provide a powerful tool for managing congestion and lowering the associated costs for MISO's customers.

Status: MISO agrees with this recommendation and has been working with the TOs through the Reconfiguration for Congestion Cost Task Team (RCCTT) to develop a process for accepting and evaluating requests. Considerable progress has been made. However, the current process can be enhanced in two areas: 1) MISO should developed a robust process for MISO 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 external (or MISO identified) requests for 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 should add its own robust process for identifying, evaluating, and implementing economic reconfigurations and MISO should evaluate TO responses to reconfiguration requests and ensure comparability to reliability evaluations.

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, then 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. Therefore, when the NMRTO's shadow price is much lower and does not converge with the MRTO's shadow price, the relief requested from the NMRTO should increase. This would 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". Oscillations have become a substantial issue as rapid-ramping wind resources in both MISO and neighboring RTOs load the same constraints.

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 and has indicated that it will evaluate potential solutions. In 2021, MISO and SPP implemented a near-term tool using "predicted" UDS flow to address oscillations, but it has not yet been configured properly to be effective. MISO believes the IMM solution, though likely better, will require more significant changes and is not currently pursuing it. 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. MISO has begun discussing the benefits of predicted flow with PJM, but little progress has been made. Lastly, MISO plans to work with the IMM to develop convergence metrics for flowgates to review.

Next Steps: MISO should use the tool properly and assess its effects. After making this assessment, MISO should determine whether a more efficient solution is warranted to address oscillations and work with the IMM to identify the other improvements in the relief request software that will be 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. MISO and SPP are reviewing M2M effectiveness, including a retrospective evaluation of M2M coordination and flowgate identification. This recommendation is at a medium priority behind the Freeze Date Firm Flow Entitlement (FFE) and the Order 881 projects.

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 in the near term.

2019-3: Develop improved capabilities to receive and validate current and forecasted dynamic transmission ratings

For years we have reported unrealized annual savings well in excess of $100 million that would have resulted from increased use of AARs and Emergency Ratings. In 2023, these savings climbed to $270 million, $34 million of which occurred on one constraint. The first step to realize these savings is for the MISO TOs to commit to providing AARs and Emergency Ratings. However, MISO's current systems and processes would not allow it to capture all these savings. Our prior reports have identified key recommended enhancements, including:

1. System Flexibility: MISO should enable more rapid additions of new AAR elements.
2. Forward Identification: MISO should support identifying additions to AAR programs based on forward processes including outage coordination.
3. Forecasted Ratings: MISO should enable use of forecasted AARs in the day-ahead market and Forward Reliability Commitment Assessment (FRAC). Currently, MISO does not have a process to receive or use forecasted ratings.

In addition, we recommend MISO make changes to support current and future needs related to verification of transmission ratings and situational awareness. MISO currently does not receive or maintain important data on transmission elements including: 1) Rating Methodologies, 2) limiting elements for transmission constraints, and 3) response times for post-contingent actions. We recommend MISO make necessary changes to enable receipt of this information, which will improve its operational awareness and transmission planning. Although the benefits of the last three improvements would be difficult to quantify, we believe the reliability and market benefits are likely large and will grow in the future.

Status: MISO agrees with this recommendation, and it has been designated as a high priority. MISO is working with its TOs to develop the system changes necessary to comply with FERC Order 881, which requires the use of AARs and Emergency Ratings in real time and forecasted ratings in the day-ahead. In advance of Order 881 compliance, MISO has made some progress in specifying additional data that will be useful in rating validation, but its validation will be limited to data quality. This raises concerns, which we plan to address by initiating efforts to monitor the TOs' compliance with Order 881.

Next Steps: MISO should complete implementation of Order 881 and begin collecting the data necessary for it to effectively validate transmission ratings. These plans should include completing its scoping of improvements that can be implemented through the MSE project or through other means to facilitate the receipt and use of AARs and Emergency Ratings.

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 2023, multiple simultaneous generation outages contributed to almost $520 million in real-time congestion costs, or 30 percent of real-time congestion costs, indicating large potential savings.

Most of the other RTOs in the Eastern Interconnect have limited authority comparable to MISO's, with the exception of ISO-New England. ISO-New England does have the authority to examine economic costs in evaluating and approving transmission outages, 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. MISO has not sought additional outage coordination authority but began working on an evaluation approach for measuring costs and benefits of rescheduling outages in 2022. 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: 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.

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 on 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: This is a new 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.

Status: MISO agrees in general that wind forecasts could be improved, and MISO is continuously making efforts to improve the forecasts. MISO has worked with IMM and one of MISO's renewable forecasting vendors to evaluate the impact of the "trend persistency" idea proposed by IMM. MISO's evaluation focused on changing the timing of MISO's API to allow vendors to leverage more recent actuals for forecasting calibration. The IMM agrees that much of the benefit can be obtained by reducing data lag.

Next Steps: Forecasting renewables accurately is key to efficient and reliable congestion management, so we encourage MISO to continue to seek improvements to the forecasts.

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 component. 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 has been aware of these issues and evaluating solution options in discussion with stakeholders and the IMM. Despite MISO and IMM agreement on the problem, this project was not prioritized in 2024. In addition, MISO has expressed a desire to evaluate this with proposed changes in the TCDCs.

Next Steps: MISO should continue to evaluate this recommendation as a stand-alone change and to implement this recommendation as soon as practicable. MISO has developed a holistic plan for improving renewable dispatch and incentives that would address this recommendation.

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 distort 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.

<u>Status</u>: MISO agrees with this recommendation and substantial progress has been made. MISO continued working with the IMM in 2023 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 2024.

<u>Next Steps</u>: The IMM will continue working with MISO on the specific recommendations to improve the out-of-market generator commitments. MISO and the IMM plan to work through these recommendations in 2024.

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 energy storage resources. This is important because these resources are likely to play a key role in operating 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.

<u>Status</u>: 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 two efforts. First is the 'LAC Evaluation' study under the uncertainty management roadmap and second is the 'Look-Ahead Dispatch (LAD) Exploration' study, which will begin in 2024.

Next Steps: MISO should prioritize further evaluation of this recommendation 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 available to operators during capacity emergencies and identifying those that could be applicable during transmission emergencies. 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.

Status: 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 2023.

Next Steps: The IMM and MISO continue to discuss the emergency procedures and supporting tools. MISO will need to 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: Clear CTS transactions every five minutes through the UDS based on the RTOs' most recent five-minute prices

We have concluded that persistent sizable forecasting errors by MISO and PJM have hindered the use of CTS. These errors severely hinder the 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.

Hence, we recommend the RTOs modify the CTS to clear CTS transactions every five minutes through UDS based on the most recent five-minute prices in the neighboring RTO area. The most recent five-minute prices are a much more accurate forecast of the prices in the next five minutes. Additionally, making adjustments every five minutes rather than every 15 minutes would result in more measured and dynamic adjustments that would achieve larger savings. We have estimated annual production costs savings exceeding $40 million, which are much larger than can be achieved by improving the current process.

<u>Status</u>: No progress was made on this recommendation in 2023. 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. However, MISO has no current plans for further effort as MISO believes the IMM solution would require significant time and effort by MISO and PJM. Given other priorities and the dependency on MSE, MISO designated this issue inactive and will consider evaluating it once resources are available. This recommendation maps to issue IR066.

<u>Next Steps</u>: 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.

<u>Status</u>: MISO agrees and is actively evaluating its operating procedures, tools, and criteria for declaring emergencies to improve consistency. MISO 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. In 2023, several enhancements were implemented to accurately and dynamically forecast "regional capacity margins", including granular visibility of Emergency Resources. Additional enhancements to MISO declarations have been realized with the implementation of the new Operator Interface (OI) tool. The OI provides additional functionality for emergency declarations and additional features are planned for future development cycles.

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. CTS transactions give the RTOs the ability to dynamically schedule the interface and lower the costs of serving load in both regions. 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. CTS transactions would not only be profitable, but more profitable than conventional scheduling, but for the transmission charges. This suggests that participants would utilize the CTS process if these charges were eliminated, particularly the reservation charges.

We continue to recommend MISO not wait for PJM and to 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. Although forecast errors are also an important factor limiting the performance of CTS as MISO has cited, the removal of the reservation charge is the easiest and most effective near-term improvement. This item remained inactive in 2023 and MISO does not anticipate any activity in 2024. This is a poor decision because the CTS process will not be effective unless the current charges are eliminated.

Next Steps: MISO should reconsider its decision to suspend action on this recommendation. Most of the benefits from this recommendation could be achieved by eliminating the reservation charges, so we encourage MISO to remove these charges at a minimum.

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.

Status: Some progress was made in 2023. MISO agrees with the importance of this issue and with the IMM recommendations. MISO has made some improvements in logging features within the current MCS and has put more emphasis on training for operators to facilitate clear and concise log entries. MISO indicates that requirements are being identified for further enhancements to the operator logging functionality in MCS.

Next Steps: 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. Project planning for operator logging enhancements and features is set to begin in spring of 2024.

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. Our evaluation of the LAC results in 2019 and 2020 indicates that the commitment recommendations are not accurate. In 2020, 65 percent of the LAC-recommended resource commitments were ultimately uneconomic to commit at real-time prices and in 2019 it was 69 percent. We also found that operators only adhered to 17 percent of the LAC recommendations in 2020, which may be attributable to the inaccuracy of the recommendations. We continue to recommend that MISO identify and address other sources of inaccuracies in the LAC model and, in conjunction with the IMM, develop logging and other procedures to record how operators respond to LAC recommendations.

Status: MISO generally agrees with this recommendation. In the last several years MISO has implemented tools that support the review of recommendations from LAC and operator commitments. This includes tools to measure the LAC's accuracy and metrics to assess commitment decisions. In prior years, MISO devoted additional resources to identify the causes of inaccurate LAC recommendations. MISO has made further progress in 2023, including the elimination of LAC headroom, implementation of Reg Decommitment logic in LAC, new displays to DIR dispatch down MW by LAC engines, expanded logging space for operators to provide a basis for their actions, and reduced offset entries.

Next Steps: MISO is continuing a LAC phase II project to further improve LAC's capability to manage uncertainty, congestion, and the transparency of its recommendations. We expect to work with MISO to evaluate and discuss high-value enhancements.

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 load in a large portion of MISO. Hence, these regulated utilities may invest in new resources and maintain needed existing units 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 filed for implementation of reliability-based demand curves to 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, the recently run PRA for Planning Year 2024/25 priced Zone 5 in Missouri in shortage during the spring and fall seasons, setting prices for the year 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 due to the 1-in-100 loss of load expectation (.01 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 with 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.

Status: This is a new recommendation.

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 predicted capacity resulting from a capacity expansion model (i) predicts an excessive amount of intermittent renewable resources will be built and (ii) understates investment in dispatchable and storage resources. Second, our initial review of some of the 9 classes of benefits MISO plans to estimate indicate that it is highly likely that the benefits will be substantially overstated. Together, these concerns are troubling because they may prompt costly transmission investment that is uneconomic and addressing perceived transmission needs that will never arise.

Therefore, we recommend MISO develop improved methodologies and assumptions for Tranche 2 and future LRTP Tranches, including:

1. Developing a "no-transmission" base case (No tranche 2). This is necessary to accurately estimate the a) fuel and congestion savings, b) energy savings from reduced losses, and c) capacity savings from reduced losses. Using forecasted siting assumptions that are based on the economic incentives provided by the market with and without the new transmission.
2. Including an evaluation of energy storage alternatives when evaluating the benefits of transmission investment.
3. Eliminating the following classes of benefits:
    - *Avoided capacity cost.* MISO's methodology assumes more capacity will be needed if Tranche 2 is not built. However, increased local capacity requirements in constrained zones and energy price signals will shift capacity over time to constrained areas where resources will be fully deliverable. Hence, there is no reason to expect
    - *Decarbonization*: Because the dispatch costs of renewable resources include the production tax credits (PTCs) that they receive, the production cost savings captures the decarbonization benefits. Hence, estimating separate decarbonization benefits will double-count these benefits. Because PTCs accurately reflect the social cost of carbon, there is no reasonable basis to calculate additional decarbonization benefits.
    - *Mitigation of reliability issues*: MISO proposes quantifying this benefit by assuming it will shed load to address voltage or other local issues (without Tranche 2). This is not realistic because, in reality, these issues are addressed by activating thermal proxies, reconfigurations, or by investments in other equipment. Each of these alternatives would be much less expensive than load shedding. If it is not eliminated, the benefits should be based on the costs of the next operating action or the equipment that would address the reliability issues (rather than load shedding).
4. *Benefits should be calculated for groups of projects*. It will be essential to calculate the benefits for individual groupings of investments in Tranche 2 to ensure that only those projects that qualify as "no regrets" investments are included, while investments that have little or no value in a more realistic scenario are removed from the portfolio.

Status: MISO has engaged the IMM on these issues. While it will not consider revising Future 2A, it has committed to analyzing additional sensitivities in its LRTP Tranche 2 cost-benefit analysis. It proposes to adopt Future 1A for the sensitivity analysis, which is not ideal because it understates the levels of dispatchable resources, storage, and load that are likely to exist in the future. MISO also plans to adopt an improved capacity expansion model when it develops revised Futures cases going forward.

Next Steps: The IMM will review each of the proposed benefits assessments for Tranche 2 and will discuss comments and concerns with MISO. This process is underway and will continue throughout 2024. By the end of the process, we hope to be able to endorse MISO benefits methodologies as reasonable and objective.

2022-5: Implement jointly optimized annual offer parameters and improve outage penalty provisions 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 since it will not know how many seasons in which the resource will clear. MISO is considering giving participants the option of an annual offer in addition to the seasonal offers.

Additionally, MISO implemented penalties that applied to any resource with non-exempt outages exceeding 31 days as part of this new framework. This framework has created some distorted incentives for the market participants:

- We observed a number of suppliers shifting their longer outages to straddle seasons. This can be problematic for outages that are shifted from shoulder seasons into higher-demand winter and summer seasons.
- The penalty framework can make it profitable for resources that will be out of service the entire season to sell capacity and pay the penalty.
- The penalty is difficult to accommodate under the market power mitigation rules because expected penalties cannot be included in resources' reference levels under the Tariff.

To address these issues, we recommend that MISO:

1. Implement annual offer parameters that are jointly optimized with the seasonal parameters in the PRA.
2. Reform the penalty provisions and mitigation measures to improve participants' outage scheduling and offer incentives.

Status: MISO agrees with the IMM's observation on challenges associated with resource's ability to recover annual going forward cost 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. MISO also agrees to explore reforms to the penalty provisions and mitigation measures to improve participants' outage scheduling and offer incentives.

Next Steps: MISO should work to complete its evaluations in 2024.

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 maintain 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 that provides poor investment, retirement, and planning incentives.

MISO recently filed to implement a marginal accreditation framework that determines a resources' accreditation based on their expected availability during hours with the highest expected reliability risks. Since 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 developed its marginal accreditation framework in 2023, completing and filing it in early 2024. This proposal does not apply to LMRs and DERs, so we recommend MISO implement marginal accreditation for all resources. MISO is actively discussing potential changes to LMR accreditation with stakeholders in the RASC and plans to file tariff changes in 2024.

Next Steps: Continue stakeholder discussions and finalize a proposal for LMRs and DERs.

2019-5: Improve the Tariff rules governing Energy Efficiency and their enforcement

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. We recommend the following changes to ensure that the savings offered are more likely to be real:

- Clarify the Tariff to require a contractual relationship with the end-use customer that: (a) prompts an action that would not likely have occurred otherwise, and (b) transfers the energy efficiency credits from the customer to the supplier;

- Specify that baseline assumptions must reflect prevailing consumer preferences and purchase patterns, rather than minimum efficiency standards.
- Enforce the measurement and verification rules by requiring some form of credible measurement of the savings, even if simply by sampling or surveying after installation.

Status: After being inactive, MISO did consider this recommendation in 2023. MISO agrees that Tariff clarifications could be made on EE resources for ownership rights, baseline assumptions, and measurement & verification (M&V) protocols. MISO plans to review the overall assumptions, requirements, and administration of EERs under Module E-1 & Attachment UU of the Tariff and consider changes if needed. This work has yet to be scheduled.

Next Steps: MISO should work with its stakeholders and the IMM to complete its evaluation and prioritize changes to address 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 or start-up 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 recommend that MISO account for the availability impacts of the emergency designation in its accreditation.

Status: MISO agrees with the recommendation and filed in March to allow the rules restricting use of the emergency commit status to be effective for June 1, 2023 (Planning Year 2023/24). Other changes to Module C and Schedule 53 that were proposed for Planning Year 2024/25 have been placed on hold to ensure they align with the results of the LMR accreditation reform project. In 2022, MISO implemented rules pertaining to LMRs by imposing tighter standards for notification times and call limits. MISO initiated discussions with stakeholders about accreditation and other rules related to Load Modifying Resources in 2023. Stakeholder discussions regarding LMR reform and accreditation have continued into 2024.

Next Steps: MISO should continue working with stakeholders and develop possible alternatives for addressing this recommendation. MISO is planning to make a FERC filing related to this effort in 2024 and has designated it a high priority.

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: MISO indicated effort 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. MISO believes it is a large effort impacting a number of models and that further evaluation is required.

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 east 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 2023. Although MISO indicates that it agrees with the recommendation, it is currently in an inactive status. 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 past recommendations that MISO has addressed since last year.

2010-14: Improve the modeling of demand in the PRA by implementing reliability-based demand curves

The use of only a minimum requirement coupled with deficiency charges to represent demand in MISO's capacity market resulted historically in an implicit vertical demand curve for capacity. This did not efficiently reflect the reliability value of capacity and understates capacity prices as capacity levels continue to fall. This was particularly harmful as large quantities of resources were retired uneconomically, causing MISO's capacity levels in the Midwest region to fall below the minimum requirement in the 2022-2023 PRA.

MISO made a FERC filling in September 2023 to implement Reliability-Based Demand Curves in MISO's capacity market beginning in planning year 2025-26. A reliability-based demand curve that is sloped (rather than vertical) would more accurately reflect the reliability value of capacity in excess of the minimum requirement. It also would produce more efficient and stable capacity prices, particularly as the supply of available regional capacity moves toward the minimum planning reserve requirement. This will lower the costs of satisfying the planning reserve requirements for both regulated and unregulated participants alike.