2021 State of the Market Report for the MISO Electricity Markets

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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 the market design and operating procedures. This Executive Summary to the *2021 State of the Market Report* provides an overview of our assessment of the performance of the markets and summarizes our recommendations.

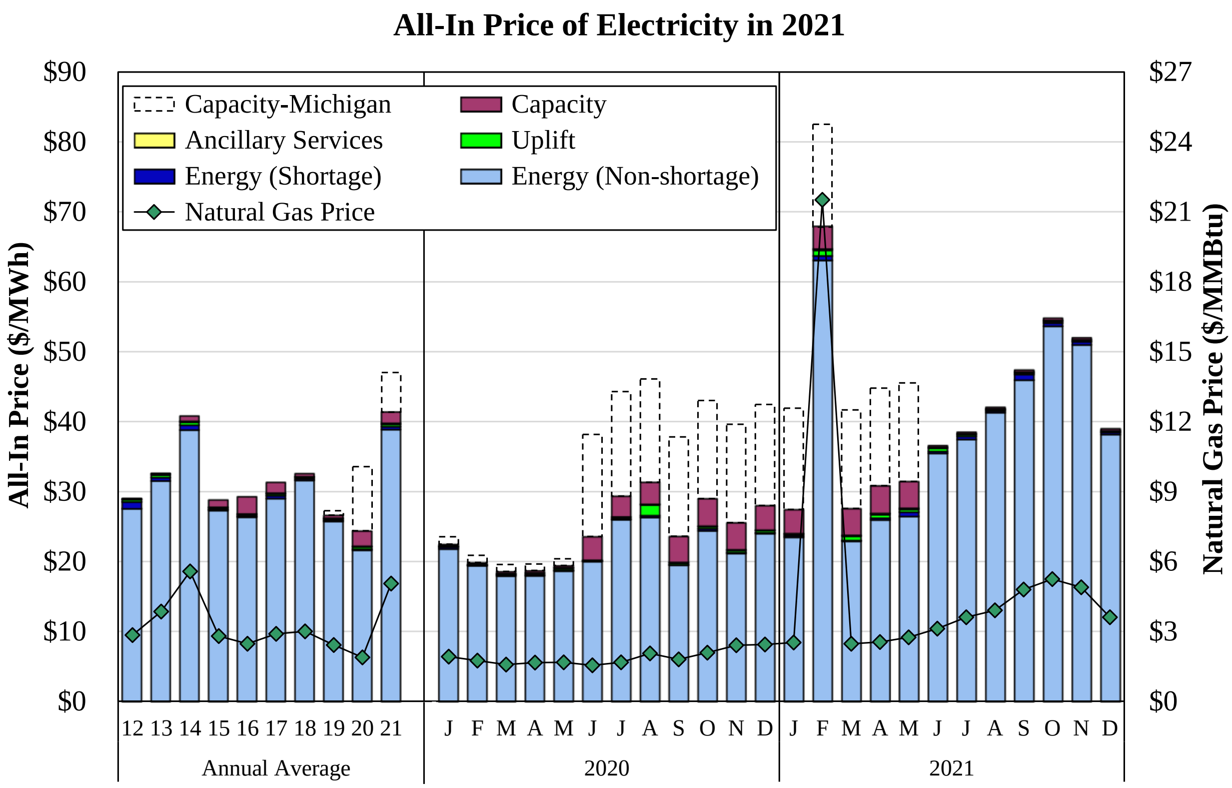
MISO operates competitive wholesale electricity markets in the Midcontinent region that extends geographically from Montana in the west to Michigan in the east and to Louisiana in the south. The MISO South subregion shown to the right in blue was integrated in December 2013.

MISO launched its markets for energy and financial transmission rights (FTRs) in 2005, its ancillary services market in 2009, and its most recent 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 in 2021

The MISO energy and ancillary services markets generally performed competitively in 2021. Multiple factors affected market outcomes in 2021, including diminishing effects of COVID-19 that increased the average load, a changing resource mix, and a significant increase in natural gas prices from historically low levels in 2020. The figure below shows an 80 percent increase in real-time energy prices throughout MISO, which averaged $39 per MWh in 2021. This increase was largely due to the 170 percent increase in natural gas prices combined with a three percent increase in average load and the effects of Winter Storm Uri in mid-February.



Frequent transmission congestion often caused prices to diverge throughout MISO in 2021. The value of real-time congestion nearly tripled in 2021 to $2.8 billion, largely because of rising natural gas prices and higher wind output throughout the year. Wind output now contributes to more than half of the real-time congestion in MISO and resulted in wind curtailments averaging approximately 660 MW per hour and as high as 6.1 GW in some hours. Roughly $730 million of the increase was related to severe congestion that occurred during Winter Storm Uri in over just six days in February.

Real-time congestion in 2021 was higher than optimal because several key issues continue to encumber congestion management in MISO, including:

- Usage of very conservative static ratings by most transmission operators;
- Limitations of MISO's authority to coordinate outages;
- Not utilizing opportunities to reconfigure the network to mitigate severely binding constraints; and
- Issues in defining and coordinating market-to-market constraints.

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 overall relationship between energy and natural gas prices, which is expected in a well-functioning, competitive market. Natural 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 that reflect a resource's marginal costs. We evaluate the competitive performance of the MISO markets by assessing the resource specific conduct of its suppliers, which was broadly consistent with expectations for a workably competitive market. We use 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. Our analysis revealed the price-cost mark-up was effectively zero in 2021, indicating the markets were highly competitive.
- The "output gap" is a measure of potential economic withholding. It remained very low, averaging 0.4 percent of load. 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 in 2021

Although MISO's markets continue to perform competitively, we have identified a number of key areas that could be improved or that will need to be improved as MISO's generating fleet evolves in the coming years. Hence, this report provides several recommendations, four of which are new this year. MISO has continued to respond to our past recommendations and implemented several key changes in 2021 that will improve the performance of its markets.

Key changes or improvements during 2021 included:

- The following key improvements to the Extended Locational Marginal Pricing (ELMP) pricing model:
  - Critical changes to emergency pricing to: a) expand the set of resources that may participate in setting prices during emergencies, and b) ensure that these resources set emergency prices at efficient levels;
  - Reforms to ensure that online fast-starting resources that are needed to satisfy MISO's demands will set energy and ancillary services prices.
  - Suspending price setting by offline fast-start resources, which has effectively addressed substantial pricing distortions.
- Lowering the Generator Shift Factor (GSF) cutoff for all constraints, which will allow a broader array of generators to be utilized to manage transmission constraints.
- Implementation of the Short-Term Reserve (STR) product, a 30-minute reserve product that allows MISO's markets to better reflect operating needs.

These improvements have measurably improved or will improve the performance of the markets or the operation of the system, which is discussed throughout this report.

Significant Events and Market Outcomes in 2021

MISO experienced several challenging events that stressed its ability to maintain reliability. We describe and evaluate these events in this report because they illuminate market performance and operational issues that do not arise under normal conditions.

Winter Storm Uri. During the February Winter Storm Uri arctic event, extraordinary and widespread extremely cold temperatures simultaneously increased demand and reduced supply. MISO ultimately shed load multiple times to maintain grid reliability and prevent system collapse. These events are evaluated in Section II.E of the report.

- Western Load Pocket (in Texas). On February 15 and 16, large generation and transmission outages in east Texas caused 300 to 800 MW of firm load shedding for over 32 hours. MISO declared a Local Transmission Emergency (LTE) rather than a capacity emergency to address the situation, which prevented prices from efficiently reflecting the value of lost load (VOLL). In the future, MISO should increase its transmission constraint demand curve (TCDC) to efficiently set prices near VOLL and ensure that the real-time market will utilize all available output from generators in the areas, which did not occur during this event.
- Extraordinary Power Flows. Most of the other emergencies that occurred during this event were directly or indirectly related to enormous exports of power to SPP or wheels of power from PJM to SPP. These flows together averaged more than 3600 MW on February 15 and 16, contributing to the more than $730 million in congestion that occurred during Winter Storm Uri. At one point, more than 33 transmission constraints were in violation. This led to two transmission emergencies and a capacity emergency in the South subregion that all led to firm load shedding.
- Non-Firm Curtailment. Each of these emergencies would have been substantially mitigated by cutting non-firm wheels and exports to SPP. This is a step in the capacity emergency procedures, but not in transmission emergencies or subregional emergencies. We have encouraged MISO to evaluate its emergency procedures to incorporate cutting non-firm exports when they would protect firm load in all types of emergencies.

Shortages caused by increased system uncertainty. Emergency events have become more frequent in recent years as weather-related anomalies, wind output uncertainty, and other unforeseen factors continued to lead to growing system uncertainty.

- For example, on March 15, wind output dropped almost 15 GW in just 12 hours, and it remained low before rising nearly 9 GW in just 8 hours on March 17. MISO was able to manage these fluctuations because they were well forecasted.
- Alternatively, MISO experienced multiple Contingency Reserve shortages between April 19 and 22 because wind output dropped earlier than forecasted. On both April 19 and 21,

wind output fell roughly 5 GW in 1 to 2 hours, resulting in reserve shortages and associated energy prices as high as $3,500 per MWh.

This underscores the importance of improving the market's ability to prepare for and respond to increasing levels of uncertainties, which we discuss in the next subsection.

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 be required to adapt to new operational and planning needs. MISO has been grappling with these issues through several initiatives, including the Renewable Integration Impact Assessment (RIIA) and the Reliability Imperative and Market Redefinition 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 improve the performance of the market as this transition occurs.

Over the past decade, the penetration of wind resources in the MISO system has consistently increased as baseload coal resources have gradually retired. MISO has effectively managed the operational challenges of these changes to date. However, 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, and changes also occur on the demand side. The most significant supply-side changes include:

- *Wind*: As wind generation increases, the operational challenges of managing this generation will increase. These operational challenges arise because of the substantial volatility of the wind output. As the magnitude of this volatility grows, so 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. A large quantity of these resources would likely 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 and Stored Energy Resources*: MISO is grappling with visibility and uncertainty around these resources. They are generally going to be part of the distribution system, yet FERC has ordered that DERs be able to participate in all aspects of the RTO markets. This will likely be very challenging.[1]
- *Energy Storage*: Order No. 841 required MISO to enable Energy Storage Resources (ESRs) to participate in the markets while recognizing the operational characteristics of ESRs. ESR costs are likely to fall as they proliferate and, together with likely increases in price volatility, should cause ESRs to become much more economic in the future.

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

MISO so far has managed the growth in intermittent resources reliably. Fortunately, MISO's markets are robust and are fundamentally well-suited to accommodate the transition in MISO's generating fleet, although we identify two critical improvements needed to satisfy MISO Reliability Imperative:

- Improving shortage pricing to compensate resources that are available and flexible and that allow MISO to maintain reliability when shortages arise; and
- Introducing a reliability-based demand curve in the capacity market that will align with the marginal reliability value that capacity provides.

In addition to these two critical changes, Section III of this report discusses the following addition changes that will be key for successful 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.

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 than required 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 this shortage value should 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. The output of most renewable resources is intermittent and increases supply uncertainty, which will likely increase the frequency of reserve shortages.

The shortage value is established by the reserve demand curve for each reserve product, so efficient shortage pricing requires properly-valued operating reserve demand curves (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 conducted a literature review and ultimately utilized a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. Based on this analysis, we recommend MISO update its current assumed VOLL of $3500 to an efficient VOLL of more than $20,000. Although we support this value as the basis for an efficient ORDC, we believe it would be reasonable to cap the maximum ORDC value at $10,000 because: (i) very few shortages would be priced in this range; (ii) pricing shortages at higher prices could result in inefficient interchange with MISO's neighbors that price shortages at lower levels; and (iii) pricing at higher price levels could cause MISO's dispatch model to make inefficient trade-offs between retaining reserves and managing flows on network constraints.

Improving the Slope of the ORDC. The slope of the ORDC should be determined by how the probability of losing load changes as the level of operating reserves falls. We estimated the probability of losing load using a Monte Carlo model that simulated: generation contingencies, wind forecast errors, load forecast errors, and NSI uncertainty. Considering all these factors produces a flatter slope for the ORDC than MISO's current approach. Adopting this approach to determine the ORDC slope along with a reasonable VOLL will result in more efficient economic signals to govern both short-term and long-term decisions by MISO's participants.

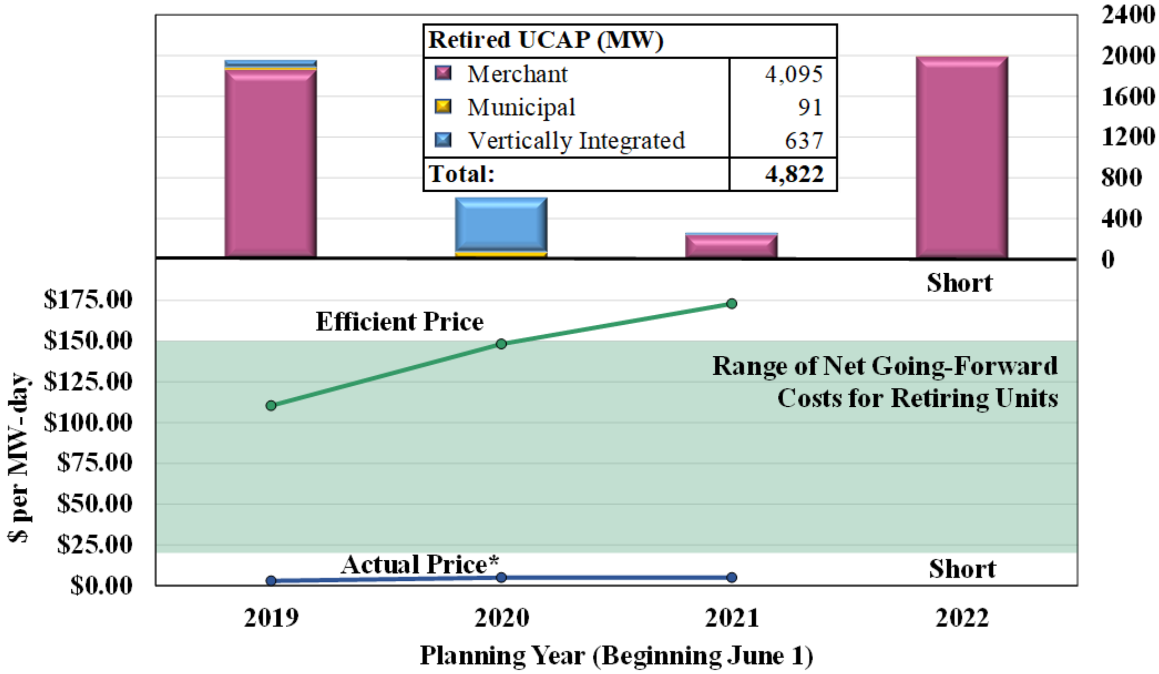
Reliability-Based Capacity Market Demand Curve

One of the most essential changes to the MISO markets that will be needed to satisfy the Reliability Imperative is to reform the capacity market so it provides efficient economic incentives. Importantly, these reforms will generally benefit MISO's regulated utilities that have historically shouldered most of the burden of ensuring resource adequacy. The problem with the current capacity market is that the demand for capacity does not reflect the true reliability value of capacity. The fixed quantity of required demand subject to a deficiency price represents a vertical demand curve for the market. The implication of a vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. Since prices will be set where the supply offers intersect with the demand curve, a vertical demand curve will almost always set the price close to zero when the market has even a small surplus of capacity.

In reality, each unit of surplus capacity above the minimum requirement will increase system reliability and lower real-time energy and ancillary services costs for consumers, although these effects diminish as the surplus increases. Hence, the true marginal contribution of surplus capacity to reliability can only be captured by a sloped reliability-based demand curve, which will set capacity prices that reflect this marginal reliability value.

The effects of setting inefficiently low prices has manifested in a shortage in the Midwest region in the 2022/2023 PRA by contributing to a sustained trend of retirements of resources that would have been economic to remain in operation. This outcome is demonstrated in the following figure, which shows: a) the economic capacity in the Midwest (by type of participant) that retired each year, b) the actual capacity prices compared to our estimate of an efficient capacity price in each year; and c) the range of net going-forward costs that resources would have needed to recover in the capacity auction to avoid suspension or retirement.

Inefficient Auction Clearing Prices and Retirements in the Midwest Region



* Actual prices are the unconstrained auction clearing prices of the Midwest. Zone 7 separated in 2019 and 2020.

This figure shows that most of the inefficient retirements that occurred over the past four years were made by merchant generators who rely on market signals to make long-term investment and retirement decisions. Captive retail ratepayers subsidize resources owned by vertically-integrated utilities and shield those resources from MISO's inefficient capacity market signals. MISO's poor capacity auction design has driven economic resources into retirement and ultimately led MISO to be short of resources in the Midwest region.

Our analysis of the reliability-based demand curve shows that the vertically-integrated utilities would generally benefit from setting efficient capacity prices that they would receive when they sell their surplus capacity. For example, regulated utilities would have received increased net revenues in the 2021/2022 PRA of more than $120 million if they had set efficient capacity prices. This would reduce the onus on regulated retail customers to support the bulk of the costs of MISO's generating resources.

The effects on the competitive participants (competitive suppliers and retail LSEs) are more important because the economic price signals from the wholesale market guide key decisions by the unregulated participants in MISO. Efficient capacity prices would have delivered almost $60 million in additional revenues to merchant generators, providing more efficient signals to maintain existing resources and build new resources. This will be key in avoiding future retirements of the economic resources and associated capacity shortages. Likewise, efficient capacity prices would have increased the costs borne by competitive retail load providers by $166.4 million per year. This is desirable because it provides incentives for these LSEs to arrange for their capacity needs and contribute to satisfying resource adequacy in MISO.

In conclusion, implementing a reliability-based demand curve should be one of MISO's highest priorities under its Reliability Imperative because it will:

- Establish stable and efficient capacity prices to provide efficient market-based incentives that govern new investment and resource retirement decisions;
- Ensure that participants supplying more than their share of the required capacity in MISO receive capacity revenues that reflect their contribution to the system's reliability needs;
- Provide incentives for load-serving entities that do not own sufficient capacity to plan efficiently by contracting for existing capacity or building new capacity; and
- Reduce the incentive to exercise market power because pricing under a reliability-based demand curve is far less sensitive to withholding than under a vertical demand curve.

As MISO's generating fleet transforms, its markets will play an essential role in integrating the new resources and maintaining reliability. Improving shortage pricing and the capacity demand curve are the highest priority changes, but Section III of the report discusses a number of other important improvements to account for the rising system uncertainty and improve the utilization of the network as transmission flows become more volatile. Although ambitious, these improvements reflect only incremental changes to the robust markets that MISO operates.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

Prior to the 2022/2023 Planning Year, MISO enjoyed a surplus of capacity beyond the minimum reliability requirement. MISO's capacity surplus dwindled in recent years as the accelerating retirements of baseload resources have mostly been replaced with intermittent renewable resources. In 2021:

- Nearly 2 GW of resources retired or suspended operations in MISO, almost all of which was coal or gas. The continuing trend of suspensions and retirements into the 2022/2023 Planning Year left insufficient capacity to meet the minimum requirement in the Midwest.
- 2.2 GW of new capacity entered MISO, including a 1,000 MW natural gas-fired combined-cycle that came online in a key constrained area of MISO South. Almost 2 GW (nameplate) of wind resources were added in 2021, but wind resources provide much less reliability value than conventional resources.

Although MISO did not clear sufficient capacity to meet the Planning Reserve Margin Requirement in the 2022/2023 Planning Resource Auction, our assessment indicates that the system's resources should be adequate for the summer of 2021 if the peak conditions are not substantially hotter than normal. This is partly because some retiring units that did not sell capacity will still be in operation this summer. 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 to be used to resolve shortages when they occur. In the long term, however, we are very concerned about MISO's resource adequacy given the relatively low net revenues generated by MISO's capacity market.

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 2021.

We find net revenues rose in all regions in 2021, partly because higher natural gas prices contributed to higher energy and ancillary services prices throughout MISO, and partly because MISO experienced a period of sustained high prices during Winter Storm Uri in February 2021. However, even with the significant transitory effects of this arctic event, the net revenues in all regions were well short of the levels needed to motivate investment in new resources. This is notable given the capacity shortage that has emerged in the Midwest region. This misalignment in almost entirely attributable to the vertical capacity demand curve we discuss above.

PRA Market Design

MISO made a filing in November 2021 to propose changes in two primary resource adequacy areas that are intended to allow MISO's capacity market to more effectively and efficiently satisfy its resource adequacy requirements.[2] These changes generally address two recommendations that we have made in recent *State of the Market* reports:

- Recommendation 2014-5: Transition to a seasonal capacity market; and
- Recommendation 2018-5: Improve the accreditation of capacity resources by recognizing resources' actual availability during tight conditions.

We provided extensive feedback and analyses to MISO in this process. We supported these changes because they are significant improvements to MISO's current market but identified elements of the proposal that reduce their benefits and should be improved in the future.

We have also recommended a variety of other improvements to the PRA. A number of these changes involve improving the accuracy of the supply and demand in the PRA, including:

- Disqualifying energy efficiency from selling capacity in the PRA.
- Developing ELCC methods to estimate the marginal capacity value of all intermittent, energy storage, and other resources not feasible to accredit based on availability.

2 Docket No. ER22-495-000.

- Improving the accreditation rules for emergency-only resources in the PRA.
- 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.

A number of these recommendations are likely to be addressed through MISO's RAN initiative discussed in Section VI.G of the report.

Energy Market Performance and Operations

The day-ahead market is critically important 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 the resource commitments needed to efficiently satisfy the system's real-time operational needs. In 2021:

- The difference between day-ahead and real-time prices was one percent, after accounting for day-ahead and real-time uplift charges, which is good convergence overall.
- However, episodes of congestion caused by generation and transmission line outages led to transitory periods of divergence in 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 increased 4 percent, whereas average cleared virtual transactions in the South fell by 25 percent in 2021. 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.
- 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.

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. Additionally, efficient price signals during shortages and tight operating conditions can reduce the reliance on revenue from the capacity market to maintain resource adequacy.

Real-Time Price Formation

Among the most important aspects of MISO's real-time price formation are the:

- Pricing of real-time operating reserve shortages and transmission shortages; and

- Ability to allow peaking resources and emergency actions to set real-time prices through the Extended Locational Marginal Pricing (ELMP) model.

In many regards, MISO's markets are at the forefront of market design. MISO jointly optimizes operating reserves and energy in the real-time markets, which allows the demand curves for reserves to contribute to setting prices when the market cannot satisfy reserve requirements. This is the most efficient means to price shortages. Shortage pricing plays a pivotal role in compensating flexible resources that are needed to resolve the shortages. This will be increasingly important as intermittent renewable resources continue to enter the MISO market. Hence, making the improvements to MISO's ORDC discussed earlier is essential.

In addition to MISO's shortage pricing, its ELMP pricing model plays a key role in achieving efficient price formation because it allows online fast-starting peaking resources (FSRs) and emergency supply to set prices when they are economic for satisfying the system demands. Initially, ELMP's effectiveness was limited, but MISO has implemented a number of our recommendations in recent years. These have included:

- Expanding the set of FSRs eligible to set prices;
- Allowing FSRs committed in the day-ahead market to set prices; and
- Relaxing the downward ramp rate for FSRs and allowing them to set prices unless they are dispatched to zero. This change was implemented in September 2021 and, together with the other changes, has significantly improved real-time price formation in MISO.

Our evaluation that is described in Section IV.C of this report shows that the average effects of ELMP on MISO's real-time energy prices more than doubled to $1.17 per MWh in 2021. While some of this increase is due to higher effects in February and higher natural gas prices, much of it is due to the improvements described above.

In addition to FSRs, emergency actions and resources can set prices in ELMP during declared emergencies. In September 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 to $500 per MWh and $1,000 per MWh.[4] MISO previously set emergency offer floors based on generator offers that resulted in inefficiently low emergency pricing. These changes have significantly improved MISO's emergency pricing with one exception. When large quantities of LMRs are deployed, the ELMP model cannot ramp the curtailments down to zero in five minutes because it cannot ramp other units up quickly enough to replace them. Hence, they can set inefficiently high prices when they are no longer needed.

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

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

This issue results in excessive non-firm imports, increased settlement costs, and inflated DAMAP uplift payments to resources that must be held down at the 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 having to ramp up the energy output of generation in the dispatch model.

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 needs of the system. Most uplift costs are the result 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 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.

Day-ahead RSG. Day-ahead RSG payments rose more than 60 percent in 2021 to total almost $100 million. Most of this increase is attributable to high fuel costs and the high RSG incurred during and after the Winter Storm Uri arctic event (almost $40 million). As in previous years, almost all day-ahead VLR costs are accumulated in two load pockets in MISO South.

Real-time RSG. Real-time RSG payments rose more than 400 percent in 2021, much of which was caused by Winter Storm Uri. MISO incurred roughly $125 million during that event, which is discussed in detail in Section II.E. Rising fuel prices contributed to only roughly 70 percent of this increase, indicating that commitment patterns played a key role in the RSG increase.

Real-Time Commitment Patterns

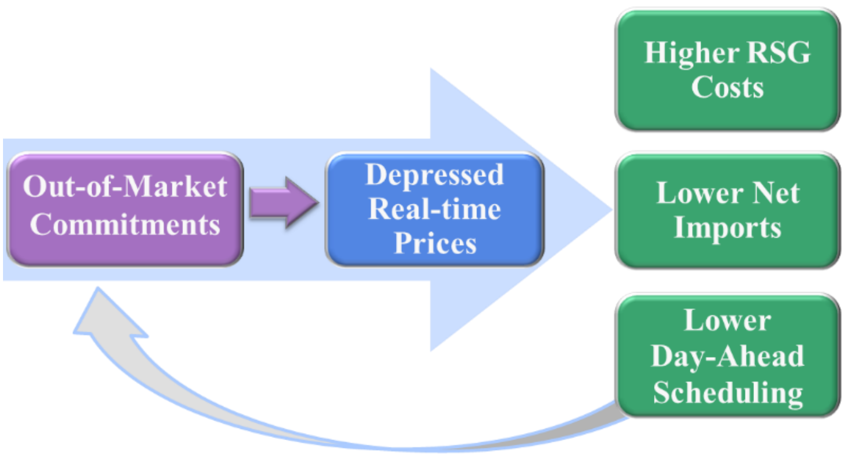
Out-of-market commitments by MISO account for most of the RSG incurred in real time, which we assess in Section IV.E of this report. This assessment reveals a pattern of increasing capacity-related commitments beginning in the summer months. During the summer quarter, MISO's day-ahead and real-time RSG payments more than doubled over the prior year. Our evaluation of these costs allows us to categorize them as follows:

- RSG costs from commitments that were actually needed to cover load, reserve requirements, and other operating requirements specified by MISO;
- RSG costs from commitments that MISO forecasted to be needed, but that we ultimately not needed; and
- RSG costs associated with excess commitments that were not forecasted to be needed.

Our evaluation indicates opportunities for substantial improvements in MISO's commitment practices, showing that:

- Only 21 percent of the RSG incurred for real-time capacity is actually needed;
- Another 21 percent appeared to be needed when the commitment decision is made.
- More than 57 percent of the capacity-related RSG costs were associated with excess commitments that were not forecasted to be needed. More than a third of the excess is associated with resources being started earlier than needed or not being decommitted when they are no longer needed.

Excess out-of-market commitments undermine the performance of the markets by creating a self-enforcing cycle of excess commitments. As this illustration shows, they depress real-time prices, which increase RSG costs and reduces supply – increasing the need for out-of-market commitments. The lower real-time prices: a) decrease net supply scheduled in the day-ahead market (averaging 98 percent of peak real-time load in 2021), and b) reduce net imports in the real-time market.



We have been working with MISO to improve real-time commitment practices to reduce excessive commitments and prevent price suppression. We have suggested that MISO:

- Allow 30-minute offline units to satisfy real-time capacity needs since they provide almost equivalent reliability value when offline as online.
- Defer commitments that do not need to be made immediately given resources' start-up times and decommitting them when no longer needed.
- Remove the real-time capacity (or headroom) requirements since STR replaces the need for headroom requirements.
- Address multiple uncertain factors probabilistically, rather than attempting to position the system to respond the worst outcome for each factor simultaneously.

These changes should reduce the amount of uplift paid to resources that are ultimately not needed and prevent real-time price suppression.

Real-Time Generator Performance

We monitor and evaluate the poor performance of some generators in following MISO's dispatch instructions on an ongoing basis. Accounting for poor performance over a period of an hour, the accumulated dragging by MISO's generators (producing less output than had they followed MISO's instructions) averaged more than 950 MW in hours when generators are generally ramping up and more than 1300 MW in the worst 10 percent of these periods. This continues to raise economic and reliability concerns because these deviations were often not detected by MISO's operators. To address this, MISO implemented a procedure in 2018 to receive real-time alerts from the IMM that identify resources that are not following dispatch. Consistently responding to these alerts will improve MISO's awareness of its generators' availability and strengthen incentives for participants to update their real-time offers to reflect their true capabilities.

Coal Resource Operations

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 economically at higher capacity factors than in 2020. This also resulted in more frequent starts and higher output levels throughout the summer of 2021 until fuel limitations and other supply chain issues compelled many coal resources to begin conserving coal and running less. 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.

Wind Generation and Forecasting

Installed wind capacity now accounts for nearly 29 GW of MISO's installed capacity and produced 13 percent of all energy in MISO in 2021. Wind output also increased by 14 percent compared to 2020 and 61 percent over the past three years to average 9.2 GW per hour. MISO set several all-time wind records in 2021, peaking for the year on December 12 at 22 GW. These trends in wind output are likely to continue for the next few years as investment remains strong.

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. 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 issues and uncertainty regarding the need to commit other resources. This convergence issue is partially addressed by net virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers. These transactions were generally profitable and contributed to the converence of day-ahead and real-time congestion on wind-impacted constraints.

Although wind generation promises substantial environmental benefits, its output is intermittent and presents operational challenges. These challenges will be amplified as wind's share of total output increases. One of the 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 set the dispatch level. Average dispatch deviations by wind units were larger than any other class of resource.

The wind deviations caused by 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. In response to previous recommendations, MISO implemented improvements to its uninstructed deviation thresholds and price volatility make-whole payment formulas in May 2019 that has significantly improved its wind forecasting.

In particular, these changes caused most wind suppliers to accept MISO's wind forecast for their resources, which greatly reduced the forecast errors because many of the suppliers' forecasts were highly biased. We identified a methodological concern that caused the MISO forecast to also be biased (although less than the suppliers'), which MISO remedied in early 2020.

Transmission Congestion

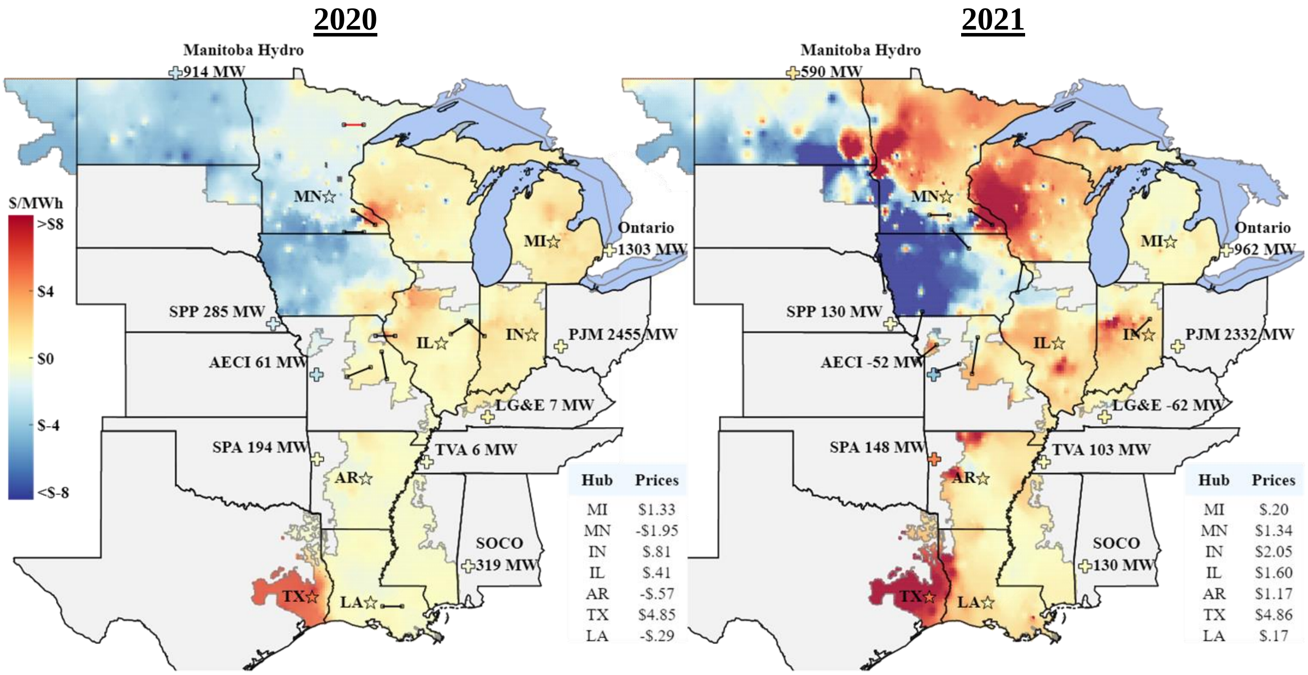
Transmission congestion costs arise on the MISO network when a higher-cost resource is dispatched in place of lower-cost ones to avoid overloading transmission constraints. These congestion costs arise in both the day-ahead and real-time markets. These costs are reflected in MISO's location-specific 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 2020 and 2021.

Congestion Costs in 2021

The value of real-time congestion rose significantly in 2021, nearly tripling to $2.8 billion. The maps below show where the congestion became more severe in 2021. This substantial increase in real-time congestion was caused be the following factors:

- Rising natural gas prices, particularly during the fall months, contributed to much of this increase because it raised the cost of re-dispatching natural gas-fired generation.
- Roughly $730 million of this increase was related to severe congestion that occurred during Winter Storm Uri over just six days in February.
- Transmission constraints loaded by wind resources accounted for an increasing level of real-time congestion— exceeding $1 billion in 2021—because of the continued entry of new wind resources in MISO, SPP, and PJM that increase loadings on key constraints.
- Available relief on wind-related constraints has fallen in recent years because of the retirement of some key coal and gas-fired resources and lower imports from Manitoba, where hydro output has been limited by drought conditions.

Average Real-Time Congestion Components in MISO's LMPs



Not all of the $2.8 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 nearly tripled to $1.6 billion in 2021. 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. In 2021, FTRs were fully funded.

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 the efficiency of congestion management are likely to be among the most beneficial initiatives to pursue. Hence, we encourage MISO to assign a high priority to addressing the issues and recommendations we discuss below.

Outage Coordination. Transmission and generation outages often occur simultaneously and affect the same constraints. In 2021, multiple simultaneous generation outages contributed to almost $850 million in real-time congestion costs—approximately 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 to 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 $320 million in congestion costs in 2021 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 more timely manner than required by the 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. Today this done on a regular basis to mitigate reliability concerns under procedures established in consultation with the transmission owners impacted by the reconfiguration. Such procedures should be expanded to economically manage congestion. The report illustrates examples of constraints that generated tremendous amounts of congestion and compelled sizable and sustained curtailments of wind resources.

Market-to-Market Coordination

There are many MISO constraints that are greatly affected by generation in PJM and SPP, and there are 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 more than doubled to total $1.2 billion in 2021, which was more than 40 percent of all congestion in MISO. Because there are so many MISO constraints that are substantially 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 the congestion. However, we also find that the coordination could be improved with four key changes and deliver substantial additional cost savings.
- *Relief request software*. Improving the software used to determine the amount of relief requested by the MRTO from the NMRTO will 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 well over $100 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 being 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 Processes*. 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.

External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2021, importing an average of 4.6 GW per hour in real time, down from 7.2 GW in 2020. MISO's imports from PJM in 2021 averaged 2.8 GW per hour, down 23 percent from 2020. Price differences at the interfaces between MISO and neighboring areas create incentives to schedule imports and exports between areas. Because of the key role interface prices play in facilitating efficient external transaction scheduling, we evaluate interface pricing in this report. We also assess and discuss MISO's coordination of interchange with PJM. Efficient interchange is essential because poor interchange can increase price volatility, reduce dispatch efficiency, increase uplift costs, and sometimes 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 agreed to adopt a "common interface" definition for the PJM interface in June 2017 consisting of 10 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, we have verified that redundant congestion pricing is occurring based on their overlapping interface definitions. In other words, when an M2M constraint binds in both markets, both RTOs will settle with an importer/exporter at the full congestion value of the constraint in each respective market. This results in duplicative payments/charges and inefficient incentives to schedule imports or exports. We encourage MISO and SPP 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 the most promising means 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 worked with PJM to implement CTS on October 3, 2017. The participation in CTS has been minimal because of high transmission charges and persistent forecast errors have likely deterred traders from using CTS. Hence, it has produced very little of the sizable savings it could generate. To improve the CTS process, we recommend that MISO:

- Eliminate all transmission and other charges applied to CTS transactions, while encouraging PJM to do the same;
- Modify the CTS to clear transactions every five minutesg through the real-time dispatch model based on the most recent five-minute prices in the neighboring RTO area; and
- Implement a CTS process with SPP based on this type of five-minute clearing process.

Our analysis of the benefits of this change in Section VII.B of this report shows that it would have raised the production cost savings in 2021 of the CTS process with PJM from actual savings of $7 million under the current approach to more than $23 million under the 5-minute adjustment approach. We estimate savings of $44 million for a similar approach with SPP. This would also improve incentives for market participants to utilize CTS as profits would have exceeded $11 million versus only $200,000 under the current approach at the PJM interface

Demand Response and Energy Efficiency

Demand response is an important contributor to MISO's resource adequacy. In 2021, MISO had 12 GW of DR resources, a 10 percent reduction from 2020, which included 4.1 GW of behind-the-meter generation. However, most of MISO's DR capability is in the form of interruptible load developed under regulated utility programs. The DR resources are registered in three primary MISO programs depending on their capabilities.

Load-Modifying Resources (LMRs). Almost 90 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. These changes are discussed in Section IX.A and 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 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.[5]
- 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.

DRR schedules and the associated payments increased sharply in 2021 to $38 million, 98 percent of which is to DRR Type I resources. Our evaluation of these payments revealed that they were largely unjustified. Less than 6 percent of them legitimately corresponded to demand curtailments. More than 94 percent of the payments produced no meaningful demand curtailments and were largely the result of opportunistic conduct. To address this issue, we are recommending two potential improvements to provide more efficient incentives and ensure that all payments made to DRRs result in real curtailments:

i. DRRs should be obligated to submit their anticipated consumption absent any curtailments, which could be the basis of legitimate settlements. This anticipated consumption data could be monitored and evaluated to identify when a participant submitted false or misleading data to inflate their settlements.

ii. MISO should establish a price floor that is significantly higher than typical LMPs, which would effectively preclude the strategies we detected. We believe this change is reasonable because 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.

Emergency Demand Response Resources (EDRs). These are called in emergencies, but 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 providing credits to EE is 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 the EE resources audited did not actually reduce MISO's peak demand, and the associated capacity accreditation

5 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.

grossly overstated the reliability value of the EE resources. Virtually all of the claimed savings were associated with product purchases by others that would have occurred with or without the EE resource. The claimed savings were not reasonably verified as required under Attachment UU of the Tariff. 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 economic inefficiency and the qualification quantities are difficult to estimate with reasonable accuracy or verify, we have recommended that MISO disqualify EE measures from selling capacity in the PRA.

Table of Recommendations

Although the markets performed competitively in 2021, we make 28 recommendations in this report intended to further improve their performance. Five are new this year, while 23 were recommended previously. MISO addressed seven of our recommendations since our last report.

The table below shows the recommendations organized by market area. They are numbered to indicate the year in which they were introduced and the recommendation number in that year. We also indicate whether each would provide high benefits and can be achieved in the near term.

SOM Number	Recommendations	High Benefit	Near Term
Energy Pricing and Transmission Congestion			
2021-1	Work with TOs to identify and deploy economic transmission reconfiguration options.	✓	✓
2021-2	Evaluate reintroducing LMR curtailments as STR demand in pricing models and UDS.		
2019-1	Improve the relief request software for market-to-market coordination.	✓	
2019-2	Improve the testing criteria defining market-to-market constraints.		
2019-3	Develop improved capabilities to receive and validate current and forecasted dynamic ratings from transmission facilities.	✓	
2016-1	Improve shortage pricing by adopting an Operating Reserve Demand Curve reflecting the expected value of lost load.	✓	✓
2016-3	Enhance authority to coordinate transmission and generation planned outages.		
2014-3	Improve external congestion related to TLRs by developing a JOA with TVA and IESO.		
2012-3	Remove external congestion from interface prices.		✓
2012-5	Introduce a virtual spread product.		

SOM Number	Recommendations	High Benefit	Near Term
Operating Reserves and Guarantee Payments			
2021-3	Evaluate and reform the unit commitment process.	✓	✓
2020-1	Develop a real-time capacity product for uncertainty.	✓	
2018-3	Improve the RDT Agreement to procure reserves on the RDT and compensate the joint parties when they are deployed.		
Dispatch Efficiency and Real-Time Market Operations			
2021-4	Develop a look-ahead dispatch and commitment model to optimally manage fluctuations in net load and the use of storage resources.	✓	
2021-5	Modify the Tariff to improve rules related to demand participation in energy markets.		✓
2020-2	Align transmission emergency and capacity emergency procedures and pricing.		✓
2020-3	Remove eligibility for wind resources to provide ramp product.		
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.		✓
Resource Adequacy			
2020-4	Develop ELCC methodologies to accredit DERs, LMRs, battery, and solar resources.	✓	
2019-5	Remove eligibility for energy efficiency to sell capacity or improve the Tariff rules governing EE and their enforcement.		✓
2017-7	Establish PRA capacity credits for emergency resources that better reflect their expected availability and 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.		
2010-14	Improve the modeling of demand in the PRA.	✓✓	✓

I. INTRODUCTION

As the Independent Market Monitor (IMM) for MISO, we evaluate the competitive performance and operation of MISO's electricity markets. This annual report summarizes this evaluation and provides our recommendations for future improvements.

MISO operates wholesale electricity markets that are 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 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.

Financial Transmission Rights (FTRs) – that are funded by the congestion revenues collected through the MISO markets and allow participants to hedge congestion costs by entitling holders to the day-ahead congestion costs paid between locations.

Ancillary Services Markets (ASM) – that include contingency reserves and regulation that are jointly optimized with the energy market to schedule resources and price shortages efficiently.

Capacity Market – that is implemented through the Planning Resource Auction (PRA) to compensate resources for meeting resource adequacy. The capacity market requires reform to facilitate efficient investment and retirement decisions.

The energy and ancillary services markets provide a robust foundation for the long-term challenges that lay ahead. Our evaluation of the markets' performance in 2021 reveals that the market performed competitively with no substantial evidence of market manipulation or market power abuses. Nonetheless, we identify a number of potential improvements in the design and operation of the markets that would allow them to operate more efficiently and provide better economic signals to market participants.

MISO continued to respond to our past recommendations, allowing the markets to evolve to meet the changing needs of the system. Key changes or improvements during 2021 included:

- Critical changes to emergency pricing to expand the set of resources that may participate in setting prices during emergencies and to ensure that these resources set emergency prices at efficient levels.

- Reforms of the Extended Locational Marginal Pricing (ELMP) model to ensure that online fast-starting resources that are needed to satisfy MISO's demands will set prices in its energy and ancillary services markets.
- A change to the ELMP model to suspend price setting by offline fast-start resources, which has effectively addressed substantial pricing distortions.
- Lowering the Generator Shift Factor (GSF) cutoff for all constraints, which will allow a broader array of generators to be utilized to manage transmission constraints and price the resulting congestion.
- A change that limits pricing at the Value of Lost Load (VOLL) during load shed events to apply only during capacity emergency events. However, MISO agreed to set prices near VOLL during transmission emergencies that result in load shedding by adjusting its Transmission Constraint Demand Curves (TCDCs).
- Implementation of the Short-Term Reserve (STR) product, a 30-minute reserve product that allows MISO's markets to better reflect operating needs.

These changes should improve the performance of the markets and the operation of the system, particularly the implementation of Short-Term Reserves. We discuss these improvements in more detail throughout the remaining sections of this report. While these improvements are valuable, we also identify and continue to recommend essential changes to MISO's shortage pricing, capacity market design and accreditation, and congestion management. These changes will provide substantial short-term benefits. More importantly, they will position MISO to successfully navigate the transition of its fleet to much higher reliance on intermittent and energy storage resources.

These and our other recommendations are listed and discussed in Section X of the report, which describes the status of each existing recommendation and identifies recommendations that have been addressed by MISO over the past year.

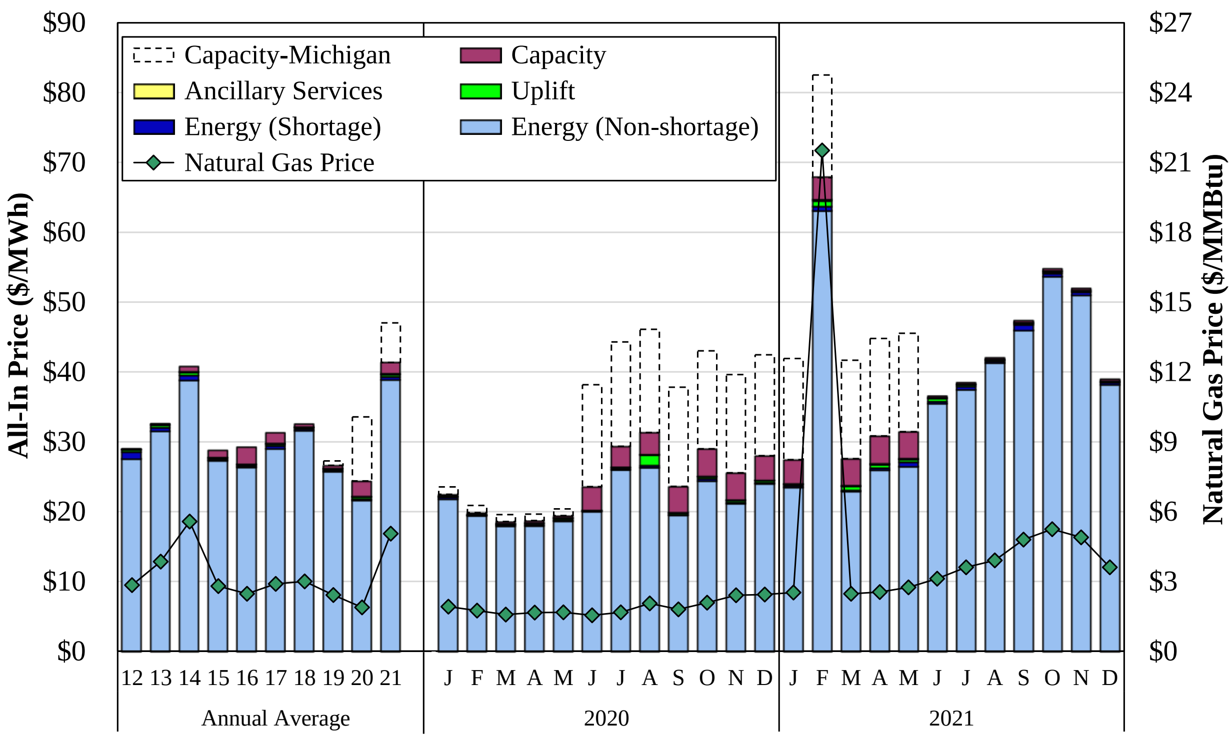
II. Price and Load Trends

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 2021

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 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.[6] We separately show the portion of the all-in price that is associated with shortage pricing, as well as the higher all-in price component in Michigan associated with the much higher capacity price in Michigan in the 2020/2021 planning year. 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
2020–2021



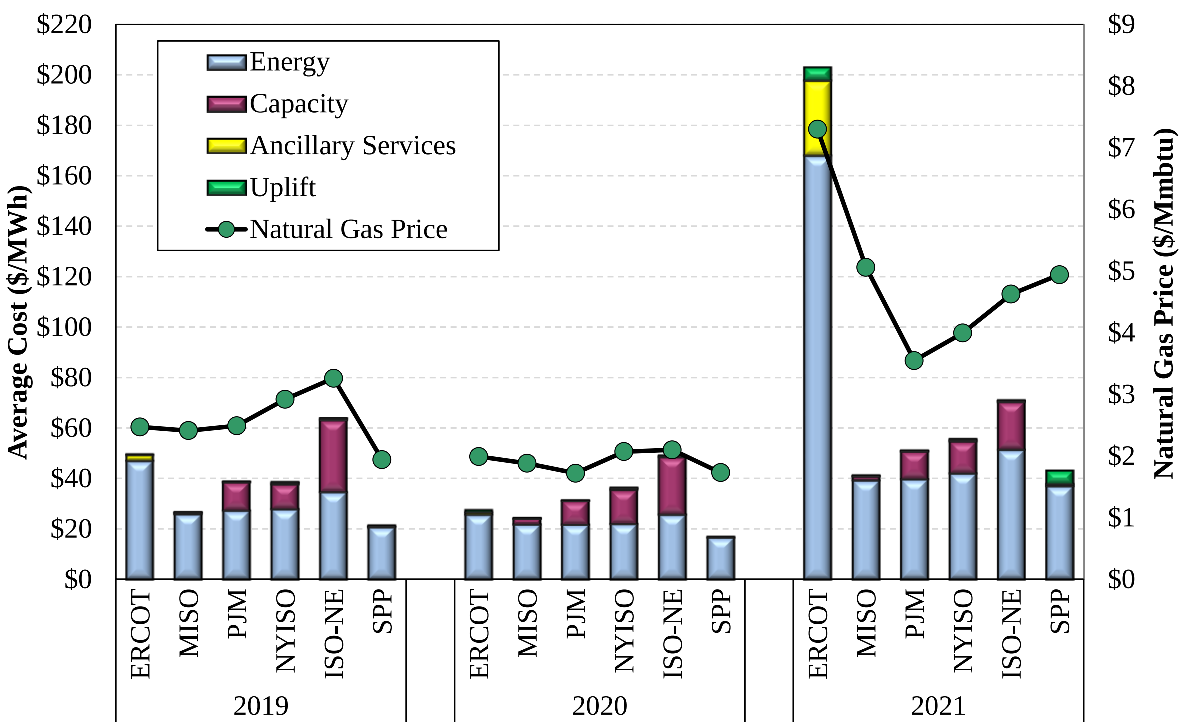
6 The non-energy costs are shown on a per MWh basis by dividing these annual costs by real-time load.

The all-in price rose 69 percent in 2021 to an average of $41 per MWh. This increase was caused by rising fuel prices and the effects of the Winter Storm Uri arctic event.

- Energy prices rose by 80 percent to the highest level since 2014 as natural gas prices increased nearly 170 percent. Much of the energy price increase was due to extremely high natural gas and energy prices in one week in February during Winter Storm Uri.
- Average load rose 3.3 percent as the impacts of the pandemic diminished in 2021.
- Shortage pricing contributions remained low at less than one percent of the all-in price.
- The ancillary services component contributed only $0.13 per MWh.
- The capacity component of the all-in price remained relatively low, particularly during the 2021/2022 planning year when the auction cleared at around two percent of CONE.
- The uplift component of the all-in price remained relatively constant at $0.32 per MWh.[7]

The figure indicates that natural gas prices continued to be a primary driver of energy prices. This correlation is expected because fuel costs are the majority of most suppliers' marginal production costs. In competitive markets, suppliers have strong incentives to offer at their marginal costs, so fuel price changes result in comparable offer price changes. To compare these results to other RTOs, Figure 2 shows the all-in prices in the Eastern RTOs and ERCOT.

Figure 2: Cross Market All-In Price Comparison
2019–2021



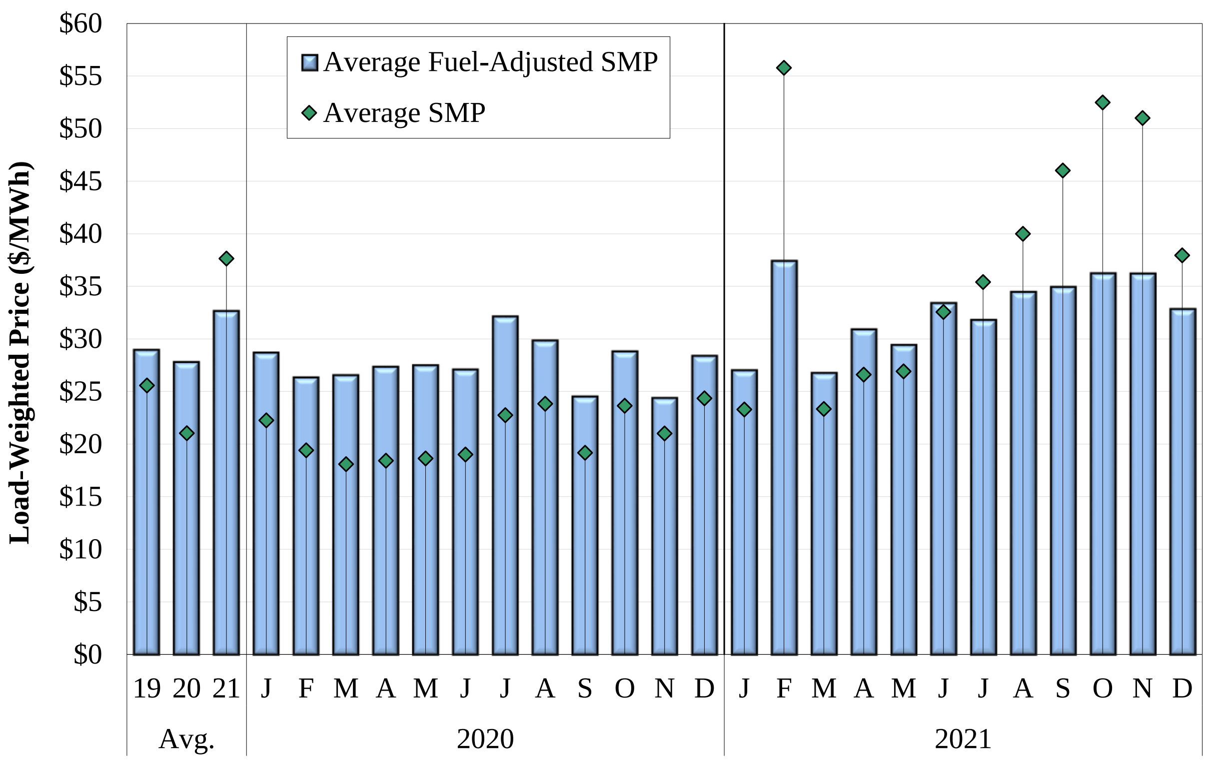
7 Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs, and Price Volatility Make-Whole Payments (PVMWPs).

Each of these RTO markets have converged to similar market designs, including nodal energy markets, operating reserves and regulation markets, and capacity markets (with the exception of ERCOT). 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 capability of the network.

In Figure 2, MISO exhibits among the lowest all-in prices because of its low natural gas prices, weak shortage pricing, and lack of a functional capacity market. ERCOT lacks a capacity market entirely but has much stronger shortage pricing. ISO New England's high 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 the change in fuel prices, we calculate a fuel price-adjusted System Marginal Price (SMP) based on the marginal fuel in each five-minute interval with each interval's SMP indexed to the three-year average of the marginal fuel price.[8]

Figure 3: Fuel-Adjusted System Marginal Price
2020–2021



While the nominal SMP in 2021 increased by 79 percent relative to 2020, the fuel-price adjusted SMP rose by just 17 percent. This indicates that some of the increase in energy prices were due to factors other than fuel, including fewer average hourly imports, coal conservation measures, and a shrinking supply of generation as resources continue to retire.

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

B. Fuel Prices and Energy Production

As natural gas prices rebounded from historic lows and rose to the highest levels in years, the relative economics of MISO's resources changed significantly. This substantially improved the economic operating margins for coal resources and led to higher coal output (that was tempered by supply chain issues) and decreased output from natural gas-fired resources. Additionally, the resource mix continued to evolve in 2021, as 1.9 GW of retirements and suspensions were replaced by additions of 2 GW of wind resources in the Midwest and a 1 GW combined-cycle gas resource in the South. This constitutes a net reduction in usable capacity since the 2 GW of installed wind capacity translates to only a few hundred MWs of Unforced Capacity.

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 2020 and 2021.

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

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2020	2021	2020	2021	2020	2021	2020	2021	2020	2021
Nuclear	11,866	11,701	9%	9%	17%	16%	0%	0%	0%	0%
Coal	46,341	43,123	36%	34%	34%	39%	40%	35%	88%	76%
Natural Gas	58,334	59,901	45%	47%	34%	28%	57%	64%	97%	96%
Oil	1,636	1,474	1%	1%	0%	0%	0%	0%	0%	1%
Hydro	3,696	3,695	3%	3%	2%	1%	1%	1%	3%	1%
Wind	4,304	4,454	3%	3%	12%	13%	1%	0%	61%	62%
Solar	419	1,037	0%	1%	0%	0%	0%	0%	0%	1%
Other	2,603	2,734	2%	2%	1%	3%	0%	0%	5%	8%
Total	**129,199**	**128,120**								

Energy Output Shares. The lowest marginal cost resources (coal and nuclear) became more profitable as energy prices rose and they operated at the highest capacity factors. Rising natural gas and energy prices caused coal's share of energy output to rise by five percentage points, while the energy share of natural gas resources fell by six percentage points. However, fuel supply issues and other supply chain problems led many coal resources to restrict their operations to manage energy limitations.[9] As wind capacity continued to grow in 2021, the energy output share of wind increased slightly to 13 percent. Nuclear output fell slightly as a 1 GW nuclear unit was on outage for more than half of the year in 2021.

Price-Setting. Coal resources set system-wide prices in 35 percent of hours, generally in off-peak periods. Although they produced more energy, coal resources were more inframarginal

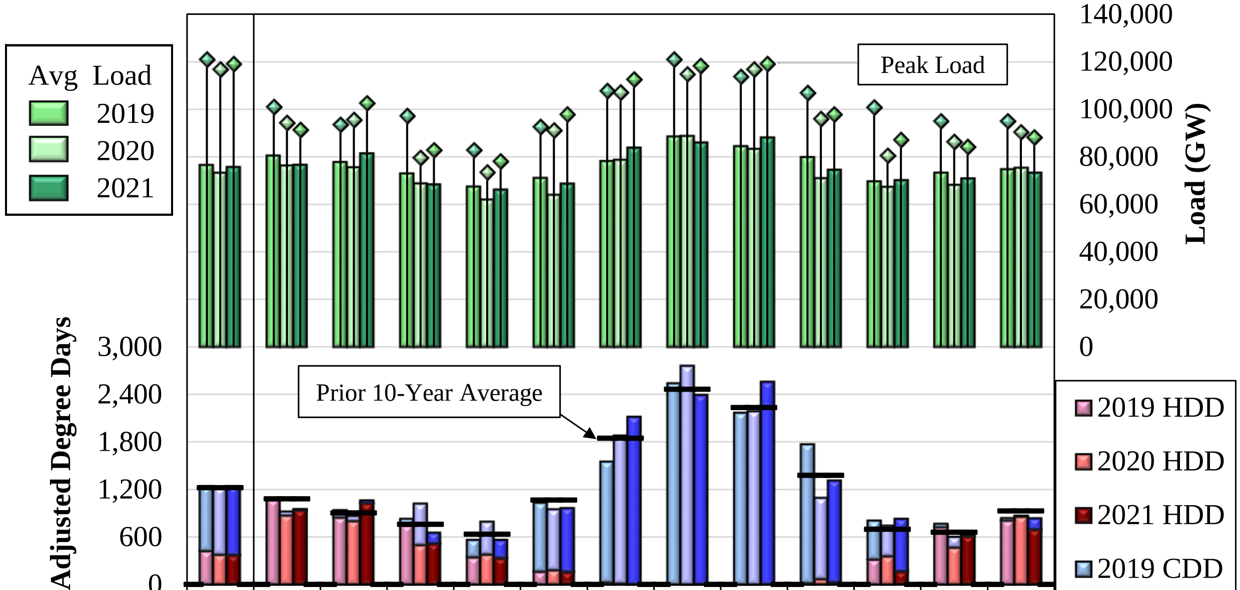
9 These issues and others related to the operation of MISO's coal resources are discussed in Section IV.H.

and, thus, set prices less frequently. Although natural gas-fired units produced only 28 percent of the energy in MISO, they set the system-wide energy price in 64 percent of all intervals, including almost all peak hours. In addition, congestion often causes gas-fired units to set prices in local areas when lower-cost units are setting the system-wide price, which is why they set LMPs in 96 percent of intervals. Likewise, wind units set prices in almost two-thirds of all intervals as growing wind output has resulted in increasingly frequent congestion.

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.[10]

Figure 4: Heating and Cooling Degree Days
2019–2021



% Chg 20-21	Avg	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	3%	0%	8%	0%	7%	8%	7%	-3%	6%	5%	4%	4%	-3%
Degree Days	1%	3%	23%	-36%	-29%	2%	13%	-13%	17%	20%	12%	6%	-3%

In March 2020, the COVID-19 pandemic led to sweeping shutdowns and lower load throughout 2020. In 2021, the effects of COVID-19 diminished and contributed to a three percent increase in average load. The number of degree days in 2021 was only one percent higher than in 20210.

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

Some extreme cold and hot weather episodes occurred throughout 2021, including:

- Beginning on February 12, arctic temperatures swept across the central U.S., resulting in multiple emergencies that we discuss below in subsection E. Average and low temperatures were 15 to 35 degrees below normal between February 14 and 17.
- Hotter than normal temperatures during some periods in the summer led to several Hot Weather Alerts, Capacity Advisories, Conservative Operations, and Maximum Generation Alerts. We discuss these events in subsection E.

MISO's annual peak load of 119.9 GW occurred on August 24 and was 1.7 percent lower than the 50/50 forecasted peak of 122 GW from MISO's *2021 Summer Resource Assessment.*

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.

Supplemental (offline) reserves only contribute to meeting the market-wide Contingency Reserve requirement (i.e., 10-minute operating reserves). Spinning reserves can satisfy the Contingency Reserve requirement, so the spinning reserve price will include a component reflecting the Contingency Reserve shortages. Similarly, regulation prices will include components associated with spinning reserve and Contingency Reserve shortages,[11] while energy prices include all ASM shortage values plus the marginal cost of satisfying the energy demands.

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.

Ancillary Services Prices in 2021

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 also shows the 5-year average price of the reserve products. The average clearing prices rose significantly for all reserve products in 2021, primarily because of changes in natural gas prices and the effects of the arctic event in February discussed later in this section. Higher opportunity costs caused by higher natural gas prices contributed to the 83 percent increase in spinning reserve prices.

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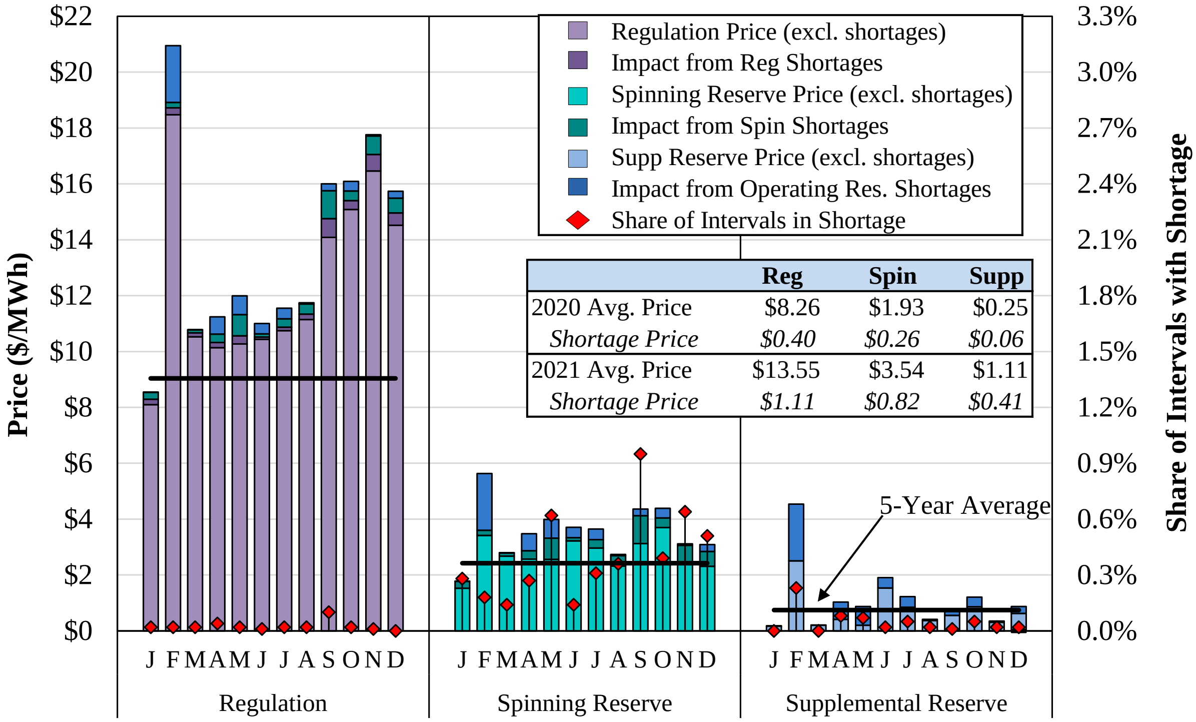
11 The demand curve for regulation, which is indexed to natural gas prices, averaged $280.24 per MWh in 2021, up from $110.45 per MWh in 2020. The spinning reserve penalty price was unchanged at $65 per MWh (for shortages < 10% of the reserve requirement) and $98 per MWh (for shortages > 10%).

Figure 5: Real-Time ASM Prices and Shortage Frequency

2021



	Reg	Spin	Supp
2020 Avg. Price	$8.26	$1.93	$0.25
Shortage Price	*$0.40*	*$0.26*	*$0.06*
2021 Avg. Price	$13.55	$3.54	$1.11
Shortage Price	*$1.11*	*$0.82*	*$0.41*

Short-Term Reserves. We previously recommended that MISO implement a regional 30-minute reserve product (short-term reserves or “STR”) to allow the markets to procure the resources needed to satisfy these regional and VLR requirements that generate substantial day-ahead RSG costs. The STR product was implemented in December 2021, but STR requirements are only applied to the entire MISO region. In roughly half of the hours each day, STR prices have averaged close to zero in the day-ahead and real-time markets, while the other half of the hours when the system is ramping exhibit higher STR prices. In the highest morning ramp hours (hours beginning 7 and 8), prices average $1 to $2 per MWh while the highest evening ramp-down hours exhibit prices from averaging $0.50 to $1.50 per MWh in the day-ahead and real-time markets. These price patterns are expected because higher ramp demands by the system reduce the available ramp capability from online resources that can provide STR.

MISO enforces STR requirements in its two primary subregions by enforcing reserve procurement enhancement (RPE) constraints over the Regional Directional Transfer (RDT) constraint that will bind when headroom on the transfer constraint plus the available STR in the importing subregion is limited. We find that the initial STR implementation is producing benefits for MISO but recommend two key improvements to greatly improve its performance:

- Application of appropriate demand curves to price shortages of short-term reserves efficiently, which we are actively working with MISO to develop.

- Expansion of the RPE constraints to enforce STR requirements in local reserve zones where large amounts of uplift costs are incurred (i.e., voltage and local reliability or "VLR" requirements). Enforcing local STR requirements will provide efficient incentives for suppliers to invest in fast-start units that can satisfy the requirements.

E. Significant Events and Market Outcomes

In 2021, MISO experienced several challenging events that stressed its ability to maintain reliability and assist its neighbors. In this subsection, we provide a description of these events, the impacts on the markets, and recommendations we identified to improve operation of the system under stressful conditions.

Winter Storm Uri Arctic Event in February

Beginning on February 12, arctic temperatures swept across the middle of the U.S. extending down to the Gulf of Mexico. Between February 14 and 17, average and low temperatures in MISO were 15 to 35 degrees below normal. MISO and its neighbors experienced unprecedented conditions that ultimately resulted in load shedding. MISO and neighboring RTOs declared both transmission and capacity emergencies as the situation unfolded. From February 13 to 19, MISO experienced the following significant market outcomes during Winter Storm Uri:

- Real-time prices reached $3,500 per MWh (VOLL) for multiple hours during load shed conditions in MISO South on February 16;
- MISO accrued congestion exceeding $313 million in the day-ahead market and nearly $700 million in the real-time market;
- Real-time RSG was more than $100 million during the event;
- Price volatility make-whole payments exceeded $14 million; and
- Up to 21 units exceeded the soft offer cap of $1,000 per MWh and 16 units exceeded the hard offer cap of $2,000 per MWh because of very high natural gas prices;[12]

Almost 30 percent and 40 percent of MISO's generation was on outage or derated in the Midwest and the South, respectively. Roughly half of these were forced outages or related to fuel supply shortages, both of which were caused by the cold weather. Ultimately, this led to tight capacity conditions in some areas and reduced MISO's flexibility for managing congestion.

Natural Gas Market Conditions. Much of the market effects listed above were caused by natural gas price spikes and shortages. As temperatures dropped, the supply of natural gas fell because of frozen gas wellheads and load shedding in ERCOT that deenergized gas pipeline components. At the same time, the demand for natural gas rose sharply, leading to extremely tight gas market conditions. Between February 12 and 17, gas prices in the Midwest soared to hundreds of

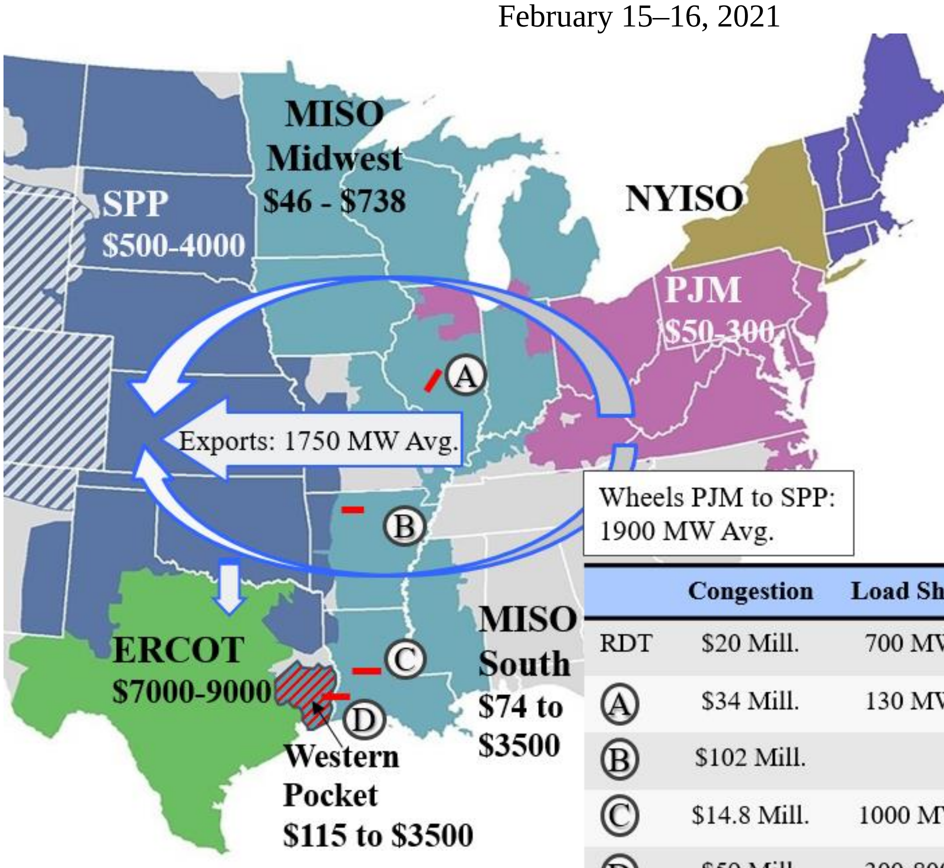
12 We implemented the soft and hard capping as part of the day-ahead and real-time market processes by submitting mitigated schedules to reflect units' verified offers.

dollars per MMBTU at some locations (as high as $700 per MMBTU) and multiple pipelines issued operational flow orders (OFO) that reduced gas availability.

These prices caused many gas-fired resources to raise their offer prices above the soft offer cap of $1,000 per MWh and/or the hard offer cap of $2,000 per MWh. As the IMM, we worked throughout the event to adjust generators' reference levels to reflect the volatile natural gas prices. This work resulted in effective enforcement of the soft and hard offer caps with no unjustified imposition of market power mitigation measures.

Transmission Flows and Emergencies. Perhaps more impactful than the natural gas issues were the extraordinary transmission flows and associated constraints. Figure 6 summarizes the flows that occurred on February 15 and 16, when reliability concerns were highest, and MISO instructed LBAs at various locations to shed load. The arrows in the figure shows the average patterns of flows from PJM through MISO into SPP, and then into ERCOT. Average LMP ranges are shown on the map in various balancing areas. The inset table shows details associated with various key constraints that caused transmission events we discuss in more detail below.

Figure 6: Market Dynamics and Outcomes
February 15–16, 2021



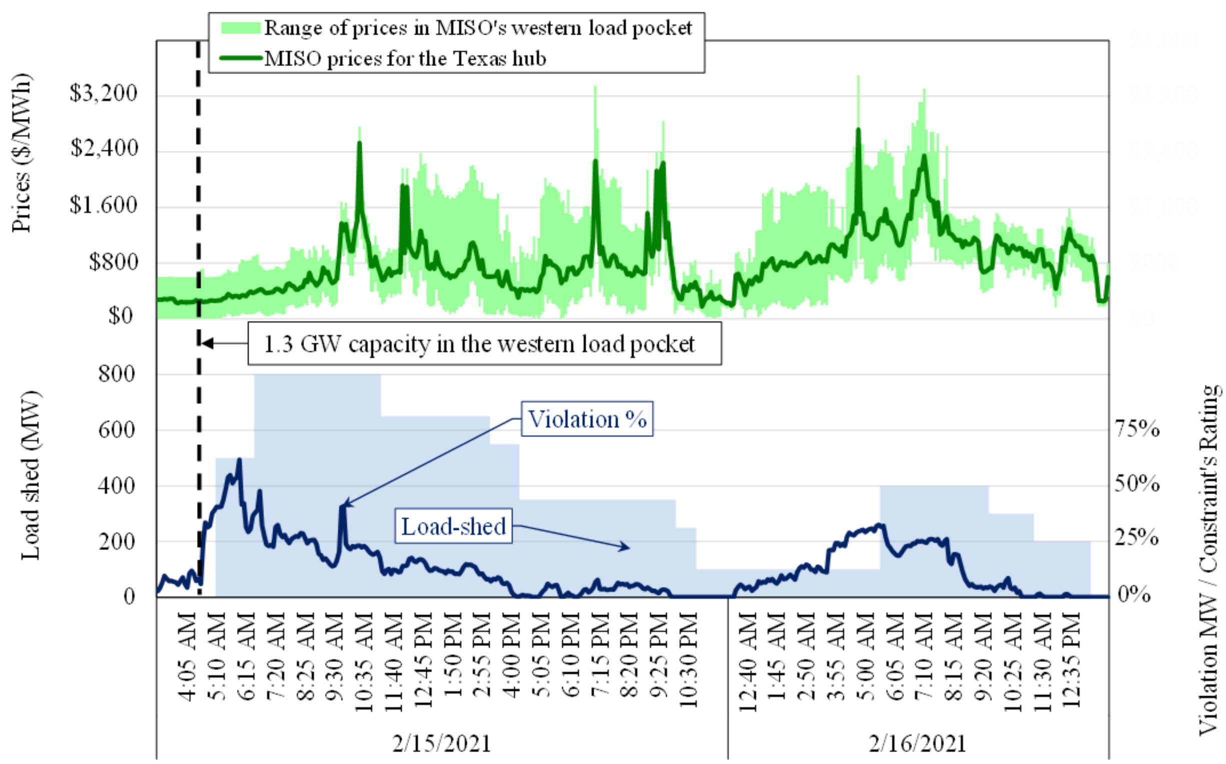
	Congestion	Load Shed	Date	Duration
RDT	$20 Mill.	700 MW	16th PM	2 Hours
A	$34 Mill.	130 MW	16th AM	7 Hours
B	$102 Mill.			
C	$14.8 Mill.	1000 MW	16th AM	4 Hours
D	$59 Mill.	300-800	15-16th	32 Hrs.

Map values incl Feb 15-16. Congestion values incl Feb 14-18

During these events, MISO experienced an unprecedented amount of congestion caused by east-to-west flows across its system. Because PJM was less impacted by the arctic cold, a significant amount of exports from PJM to MISO and to SPP (through MISO) strained MISO's transmission system. Real-time congestion totaled $733 million from February 12 to 19, of which 70 percent occurred in the South. Up to 33 constraints were violated at one point.[13] These east-to-west flows and key generator outages contributed to multiple transmission emergencies, some of which resulted in significant load shedding and other emergency actions to manage the constraints. We describe key aspects of the arctic event below and provide recommendations for addressing similar events in the future.

Load Shed in the Western Load Pocket. On February 15 and 16, large generation and transmission outages in the Western Load Pocket in east Texas led to extended firm load shedding and other high-cost operator actions (see (D) in Figure 6). In Figure 7, we show the conditions in the Western Load Pocket during the load shed event. We indicate the range of prices in the load pocket throughout the event in the top panel. In the bottom panel, we show the load shed amounts in the light blue area and the transmission violation levels plotted against the right axis.

Figure 7: Load Shed in Western Load Pocket
February 15–16, 2021



13 The most severe binding constraints were not Market-to-Market (M2M) because they were not tested. Although SPP had limited ability to help relieve the constraints, M2M coordination would have resulted in estimated payments from SPP to MISO of approximately $50 million.

The loss of 1,300 MW of resources in the load pocket early on February 15 triggered load shedding as high as 800 MW, and MISO continued to shed load through noon the following day. A major constraint into the load pocket was severely overloaded, and MISO declared a Local Transmission Emergency (LTE) rather than a capacity emergency to address the situation.[14] Most emergencies in a load pocket could be declared either as a capacity emergency (EEA) or as a local transmission emergency because capacity shortages in a pocket will almost always lead to transmission overloads as the dispatch attempts to maximize imports into the pocket.

Unfortunately, the difference in pricing outcomes resulting from these two types of emergency declarations are stark. After hurricane Laura in August 2020, MISO declared an EEA and priced the same impacted area at VOLL when load was shed. During these events, MISO declared a transmission emergency and prices averaged only $843 per MWh and did not reflect system conditions. Conditions were similar in ERCOT, where prices averaged $7,500 per MWh during the same time period.

High gas prices caused key units in the load pocket needed for managing the congestion to be more costly than the $1,000 per MWh transmission constraint demand curve (TCDC) for the impacted constraint. This phenomenon prevented the market from providing needed relief and compelled MISO to manually re-dispatch generation in the pocket. Increasing the TCDC would have improved the market's ability to manage the reliability issues and improve pricing in the area. We have recommended that MISO adjust TCDCs for transmission emergencies to ensure that VOLL is reflected at impacted nodes. Raising the TCDC to allow prices in the pocket to reflect VOLL during the load shedding would have: (1) increased charges to generators that tripped offline by $23 million, (2) raised compensation to loads by $29 million, and (3) resulted in an additional $6 million in balancing congestion.

Transmission Emergencies and Load Shed in the South. Conditions in the South Region outside the Western Load Pocket on February 15 and 16 were also dire, as outages and transmission flows through the South led to two transmission emergencies and a capacity emergency in the entire South subregion. The first transmission emergency began on February 15 and is represented by (B) in Figure 6 above. A binding constraint located near a large nuclear unit that was impacted by SPP flows was violated, and MISO manually ramped the nuclear unit down to 28 percent loading. The constraint generated more than $100 million in congestion, but fortunately it did not result in load shed. The constraint was not defined as a M2M constraint but would likely have passed the M2M test and resulted in payments from SPP to MISO of approximately $40 million. MISO did not request the M2M test for the constraint. The transmission emergency for this constraint ended on February 17.

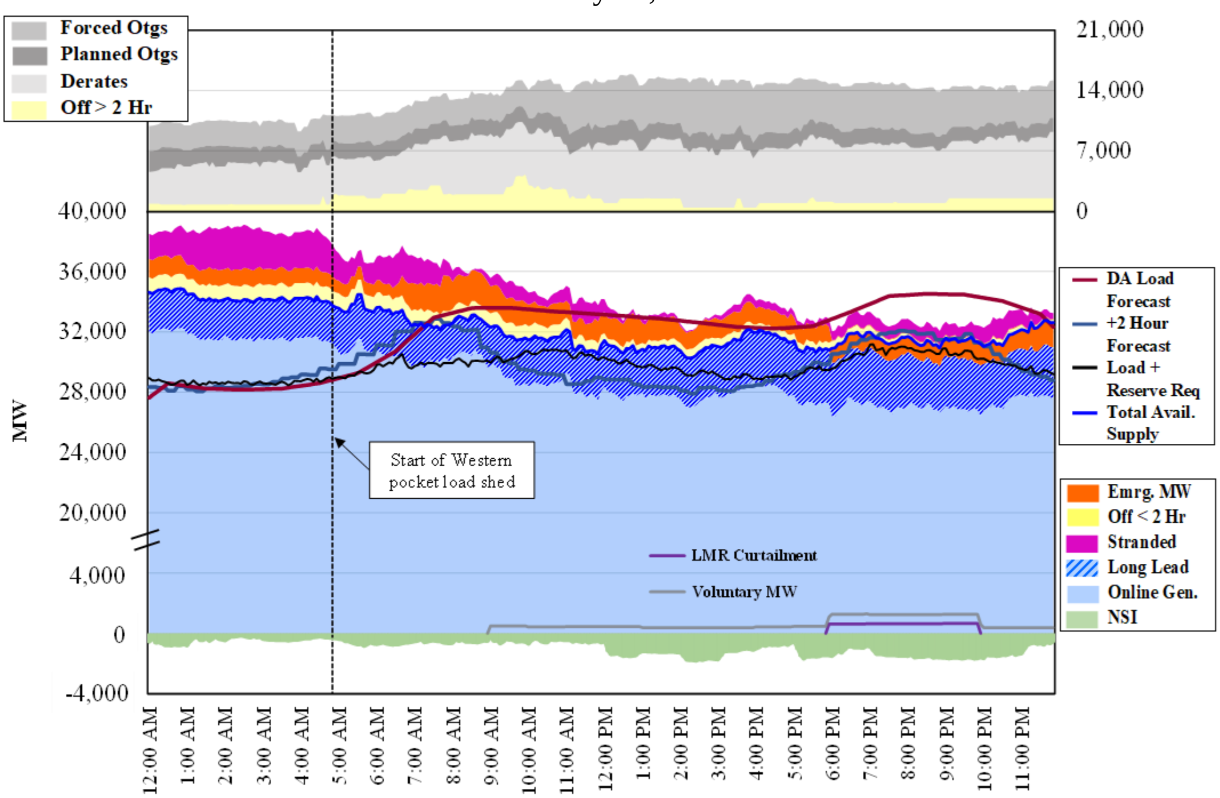
14 The constraint into the load pocket had previously been Market-to-Market (M2M), but it had been disabled and not retested. Thus, $65 million in congestion was accrued during this time, of which SPP would have owed MISO roughly $10 million in M2M settlements.

As conditions worsened throughout the day on February 15, MISO stepped through their emergency procedures and declared a Max Gen Event Step 2c in the South in the evening. This provided MISO access to LMRs and would allow MISO to purchase emergency energy from neighboring RTOs/ISOs, although the energy purchases ultimately did not occur. Power was being exported throughout the entire day to SPP, as shown in Figure 8.

Figure 8 shows each element of the supply and demand in the South. The total available supply is shown in the figure with a royal blue line and it is comprised of NSI (green area), online generation plus RDT capability into the affected area plus offline resources that can start in less than 30 minutes (light blue area), online long-lead generation (blue hatched area), and online emergency generator ranges utilized (red area under the dark blue total available supply line). The areas above the dark blue represents generation that is not immediately available, including emergency ranges not utilized (orange area), resources that are "stranded behind transmission constraints" (hot pink area), and resources offline that can start within two hours (yellow area). Other unavailable resources are shown in the top panel.

Figure 8: Capacity Balance and Load Shed in MISO South

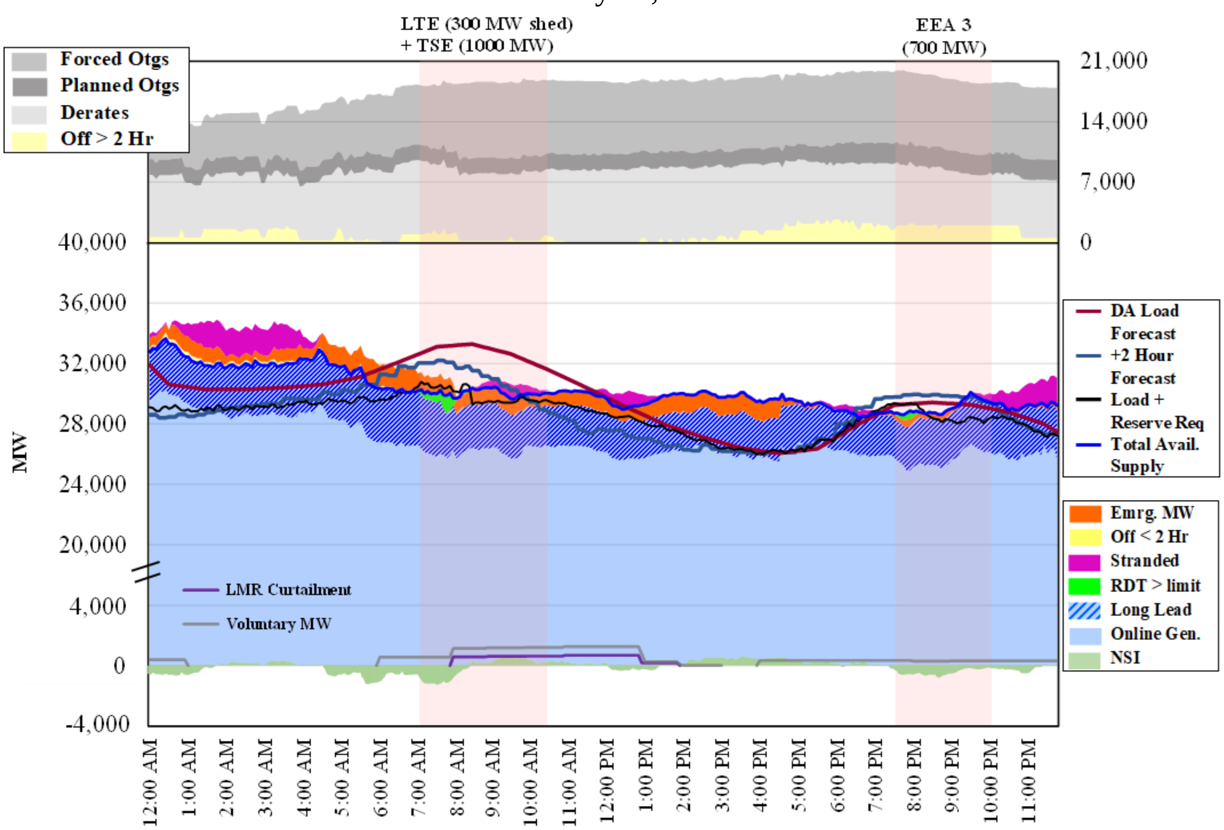
February 15, 2021



The total available supply can be compared to the total demand. Total demand is equal to the actual real-time load plus a regional reserve requirement based on the largest generator contingency. The figure includes this total demand (black line), the day-ahead forecast of total demand (maroon line), and the two-hour demand forecast when relevant (light blue line). The supply margin can be determined at any point in time as the difference between total demand (the black line) and the total available supply (the royal blue line). MISO experiences a capacity deficiency when the black line crosses above the royal blue line, which will result in MISO exceeding the RDT scheduling limit when the largest contingency occurs in the North or South.[15] Because power was being exported from MISO South on February 15, the green shaded area representing NSI is negative in the figure.

Figure 8 shows that real-time load fell in the South after MISO began shedding load in the Western load pocket, creating some headroom in the South. Throughout the day, even after MISO called a Maximum Generation Event, more than 4 GW of exports flowed from MISO into SPP. Slightly less than 40 percent of these exports are deemed to exit the South under the RDT agreement. Although conditions were tight, particularly late in the day, MISO avoided a shortage by utilizing LMRs and emergency resources. Prices averaged $823 per MWh at the South Hubs. Conditions were worse on February 16 as shown below in Figure 9.

Figure 9: Capacity Balance and Load Shed in MISO South
February 16, 2021



15 Under the RDT agreement, MISO is required to schedule transfers within limits (nominally 3000 MW from North to South and 2500 MW from the South to the North) within 30 minutes following a contingency.

During the morning ramp hours MISO declared two transmission emergencies that resulted in load shed in the South. Later in the evening, MISO declared an emergency (EEA3) for the entire South subregion and shed 700 MW of load on a pro-rata basis throughout the South. Since almost 40 percent of exports or wheels to SPP are deemed to originate in the South, maintaining the non-firm exports to SPP was a primary cause of the South load shedding.

Conclusions and Recommendations from the Arctic Event. MISO's operators performed well under extremely stressful conditions. MISO was able to maintain the reliability of the system through this event, but we identify a number of operational and market improvements indicated by our evaluation of the event. To realize these improvements, we recommend that MISO:

- Reform transmission emergency procedures and subregional capacity emergency procedures to include curtailment of non-firm wheels and exports. Such curtailments of non-firm transactions to SPP would have relieved the transmission violations and the capacity shortage in the South that caused MISO to shed firm load.
- Modify its transmission emergency procedures to raise the TCDC on the relevant constraint to (a) maximize the utilization of supply through the market dispatch software and (b) set efficient prices in the pocket. In the most severe cases, when MISO must shed load in the constrained area, this would allow prices in the area to rise to reflect the value of lost load.
- Improve MISO's emergency pricing by including actions taken in response to transmission emergencies in its emergency pricing. This will address concerns that the pricing in constrained areas was not efficient in the transmission emergencies during the Arctic Event.
- Modify its procedures to restore subregional load after it is shed as quickly as possible. It may be necessary derate the RDT to create room for the load to return.
- Improve procedures to invoke TLRs earlier in advance of a transmission emergency and associated actions.

Addressing these issues will provide MISO more options for responding to tight capacity conditions in the subregions and in smaller load pockets during transmission emergencies.

Spring Wind Output Variability and Associated Operating Reserve Shortages

During the spring months, MISO experienced high wind volatility on multiple days. This led to some periods of shortage when generation was inadequate to absorb the wind output changes. We illustrate several of these days in Figure 10. The top panel of the figure plots the 30-minute decrease in wind output and MISO's 30-minute ramp capability against the right axis. The middle panel shows the wind output (blue area) compared to the 2-hour wind forecast (solid blue line) plotted against the left axis. The bottom panel plots the system marginal price against the right bottom axis.

Figure 10: Substantial Changes in Wind Output, Ramp Demand, and Prices
March and April, 2021

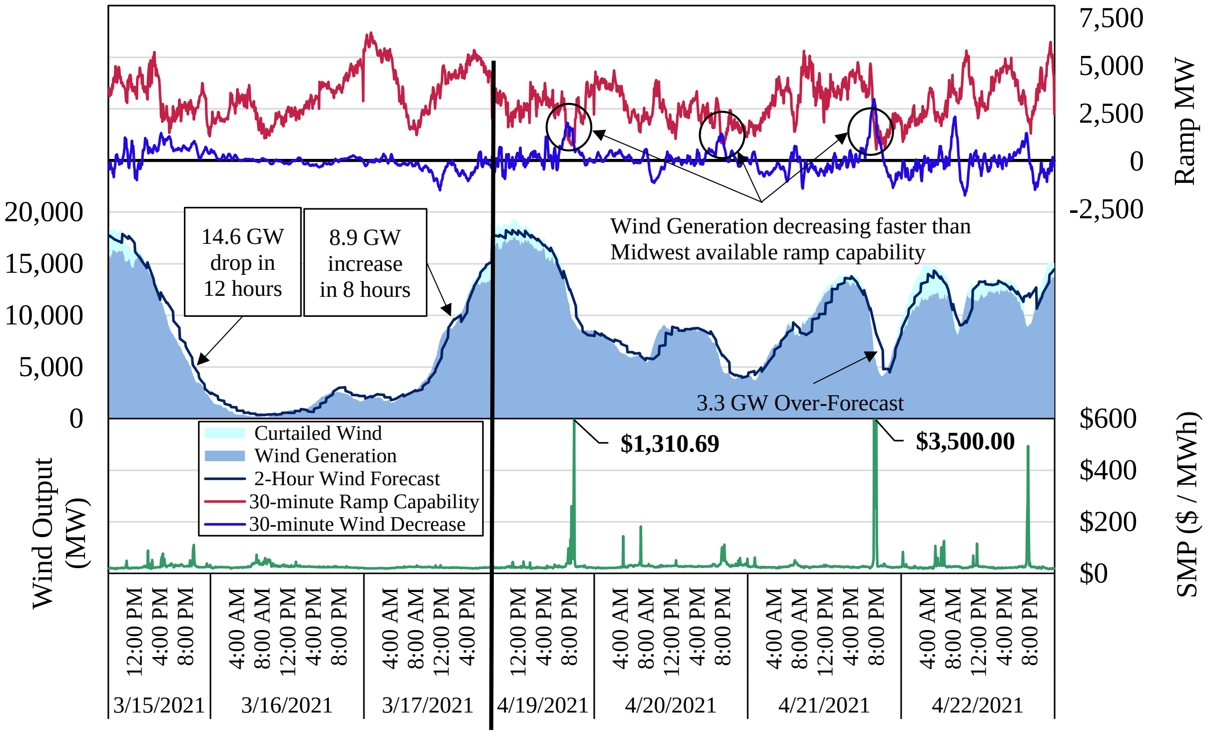


Figure 10 shows that on March 15 the wind dropped almost 15 GW in just 12 hours, and it remained low before rising nearly 9 GW in just 8 hours on March 17. The system's ramp capability was able to manage these fluctuations. However, between April 19 and 22, MISO experienced multiple evening periods when wind fell sharply and caused Contingency Reserve shortages. The Contingency Reserve shortages generally occurred when wind output dropped earlier than forecasted, and insufficient ramp capability was available to absorb the loss of wind MW. This occurred when wind fell roughly 5 GW on April 19 and 21 in 1 to 2 hours, resulting in prices as high as $3,500 per MWh.

In both cases, the shortage principally occurred because the output reduction happened early and more rapidly than forecasted. This underscores the importance of improving MISO's wind forecasting processes. Since it will be impossible to eliminate such forecast errors entirely, allowing the markets to address this uncertainty by dynamically adjusting the requirements and demand curves for the Ramp Up Capability and Short-Term Reserve products would be valuable. These products can pre-position resources to respond when uncertainties materialize and reduce the need for excess resource commitment. In the longer-term, we recommend introducing an uncertainty product to further address these issues.

III. 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 be required to adapt to new operational and planning needs. MISO has been grappling with these issues through several initiatives, including the Renewable Integration Impact Assessment (RIIA) and the Reliability Imperative and Market Redefinition initiatives.

With the exception of its capacity market, 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. 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 dramatic changes anticipated in MISO's generation portfolio and the implications of these changes. We then identify the key market issues and non-market issues and improvements that will allow MISO to successfully navigate this transition.

A. MISO's Future Supply Portfolio

Over the past decade, the penetration of wind resources in the MISO system has consistently increased as baseload coal resources have gradually retired. To date, MISO has effectively managed the operational challenges of integrating intermittent resources and losing conventional resources. However, the trend of increased intermittent resource penetration and retirement of conventional resources is almost certainly going to accelerate as large quantities of solar and battery storage resources join new wind resources in the interconnection queue. Currently, MISO's interconnection queue is comprised of mostly renewable resources, sometimes combined with batteries to form "hybrid" facilities. MISO has more than 800 active projects in the interconnection queue, totaling over 130 GW. More than two thirds of these are solar projects or hybrid solar projects and another 10 percent are wind projects.[16] Distributed energy resources may also grow and play a more substantial role in MISO in the future.

Changes are also anticipated on the demand side. MISO's Transmission Expansion Planning (MTEP) study includes a scenario that examines a significant electrification of the transportation sector with the widespread adoption of electric vehicles. 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 11 shows the anticipated mix of

16 MISO Futures Report, April 2021 (updated December 2021), https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.

resources based on MISO's Futures Scenarios that are used for MTEP studies, RIIA, and resource adequacy studies. We show Future scenarios 1 and 3, which are intended to bracket the possible growth in renewables that MISO anticipates through 2039. Future 3 scenario includes significant assumed electrification of both the transportation sector (primarily electric vehicles or EVs) and residential heating/cooling (advanced heat pumps). While intended to bound the possible scenarios, recent state-level policy initiatives and potential federal initiatives may result in even more significant changes.

Figure 11: Anticipated Resource Mix
By Fuel Type

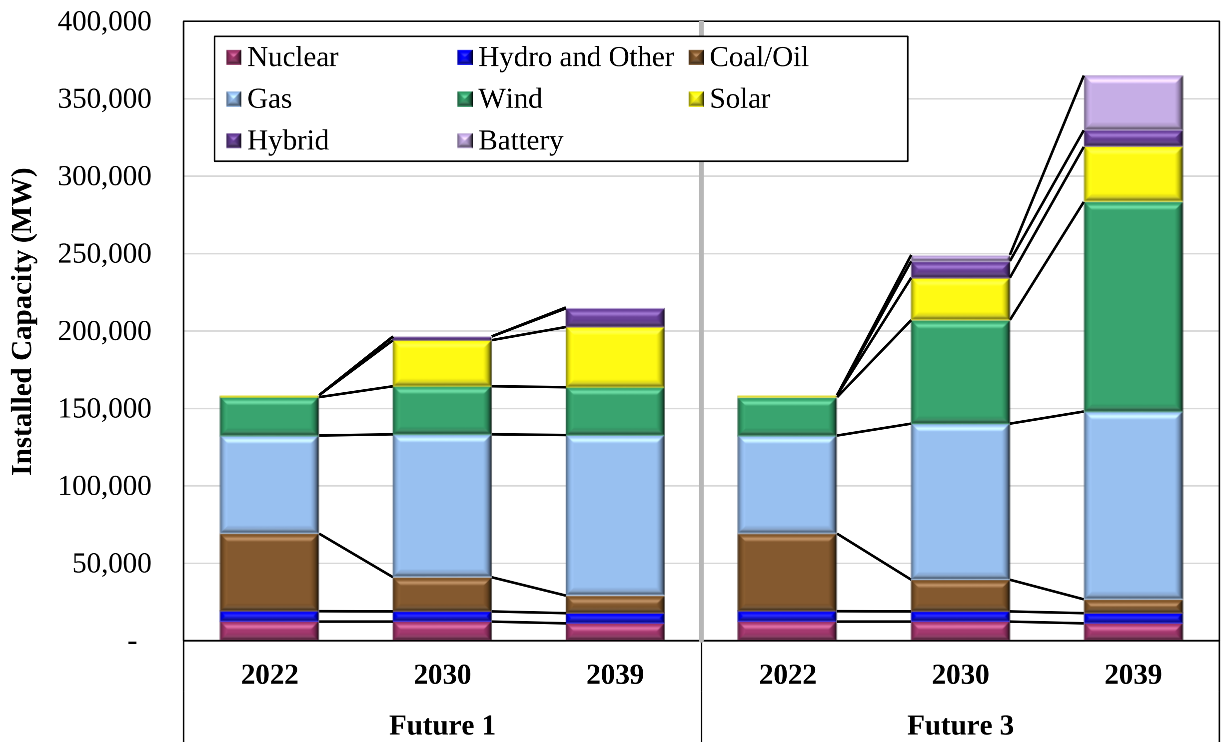
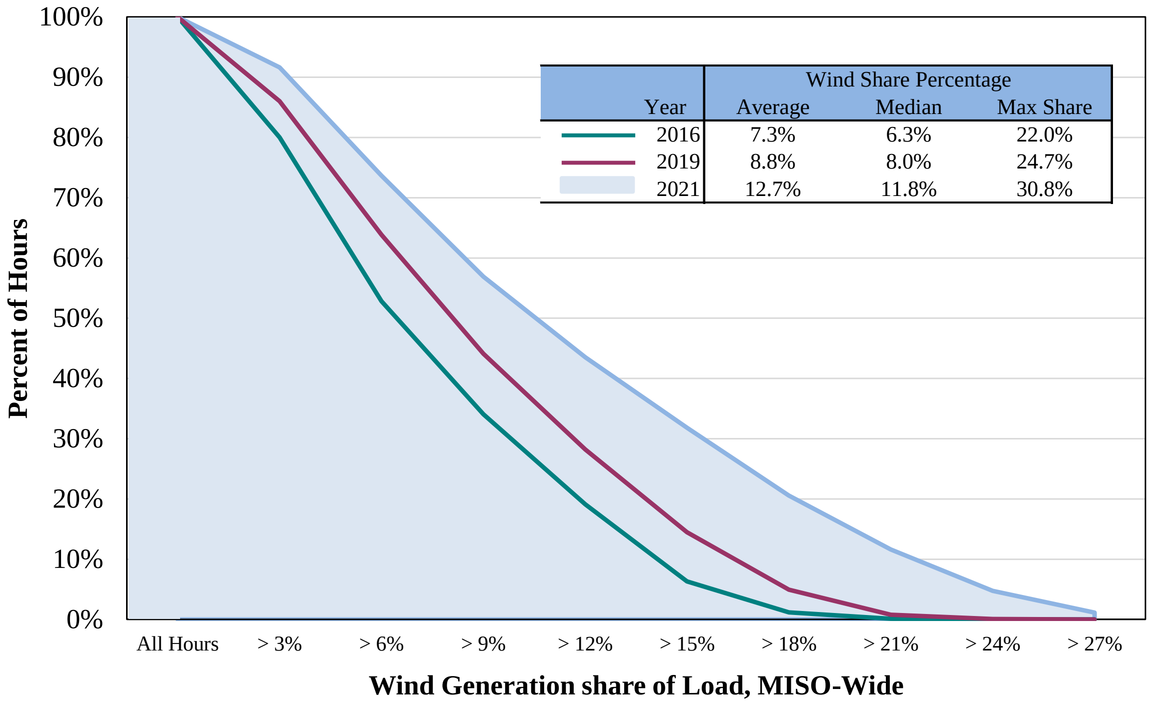


Figure 11 shows that both scenarios forecast substantial penetration of solar resources in the coming years, which is likely based on the fact that solar resources dominate the interconnection queue. Both scenarios also show that coal-fired resources are likely to retire rapidly over the next 10 years, much of which will be replaced by natural gas-fired resources. This expectation is reasonable because MISO will continue to have a need for dispatchable generation that can be used to satisfy load and manage congestion in the face of the increase in uncertain intermittent output. The Future 3 scenario forecasts that gas-fired resources will provide the dispatchable energy needed to maintain reliability, but advances in batteries may enable some of these resources to be displaced by storage resources. In such a scenario, it will become even more critical that MISO improve its market software to allow the markets to optimize both long- and short-duration storage resources. This will require MISO to develop a look-ahead dispatch and commitment model that optimizes multiple hours, which we recommend MISO begin evaluating.

Expansion of Wind Resources

Average hourly wind output continued to grow in 2021, rising 10 percent over 2020 to almost 9 GW. Hence, wind resources continue to produce increasing shares of the total generation in MISO, increasing from 12 percent of all energy in 2020 to 13 percent in 2021. However, wind generation varies substantially from day to day and often from hour to hour. In some hours, wind generation served nearly one third of the load in MISO in 2021, which presents increasing operational challenges that MISO must confront. Figure 12 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 at least that wind percentage share of load prevailed. So, for example, in 2021, in 50 percent of the hours, nearly 12 percent of the load was served by wind.

Figure 12: Share of MISO Load Served by Wind Generation
2016–2021



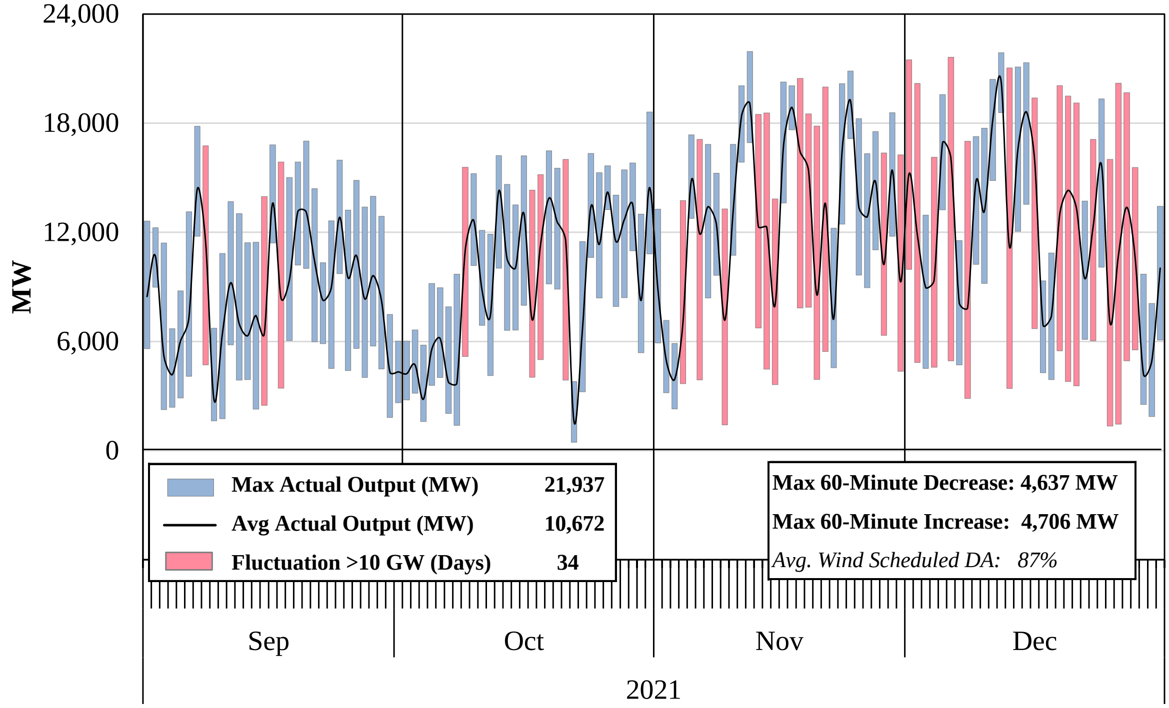
This figure shows that wind output as a share of load in MISO has been growing rapidly. To see the changes over time, notice in the figure that for half of the hours of the year, wind was serving more than 6 percent of the load in 2016, 8 percent in in 2019, and roughly 12 percent of the load in 2021. We expect this trend to continue and, as wind generation increases, the operational challenges of managing this generation will increase.

Wind Fluctuation. The operational challenges associated with managing wind generation arise because of the substantial volatility of the wind output. As the magnitude of this volatility grows, so do the errors in forecasting the wind output. To illuminate these challenges, Figure 13 shows the daily range in wind output along with the average wind output each day from September through December 2021, a period during which wind output was relatively high. This period included a new all-time peak wind output of almost 22 GW on December 12, a day when wind served more than 27 percent of the 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 dropped by as much as 4,600 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 13: Daily Range of Wind Generation Output

September – December 2021



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. Conversely, it will increase the value of having dispatchable conventional resources that can cycle on and off for much shorter periods. Finally, Figure 13 also shows that MISO continues to experience periods when wind 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 volatility 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., HVDC, PARs, switches, and battery facilities) will be pivotal in integrating much larger quanitities of wind resources. We discuss possible approaches in the next subsection.

Penetration of Solar Resources

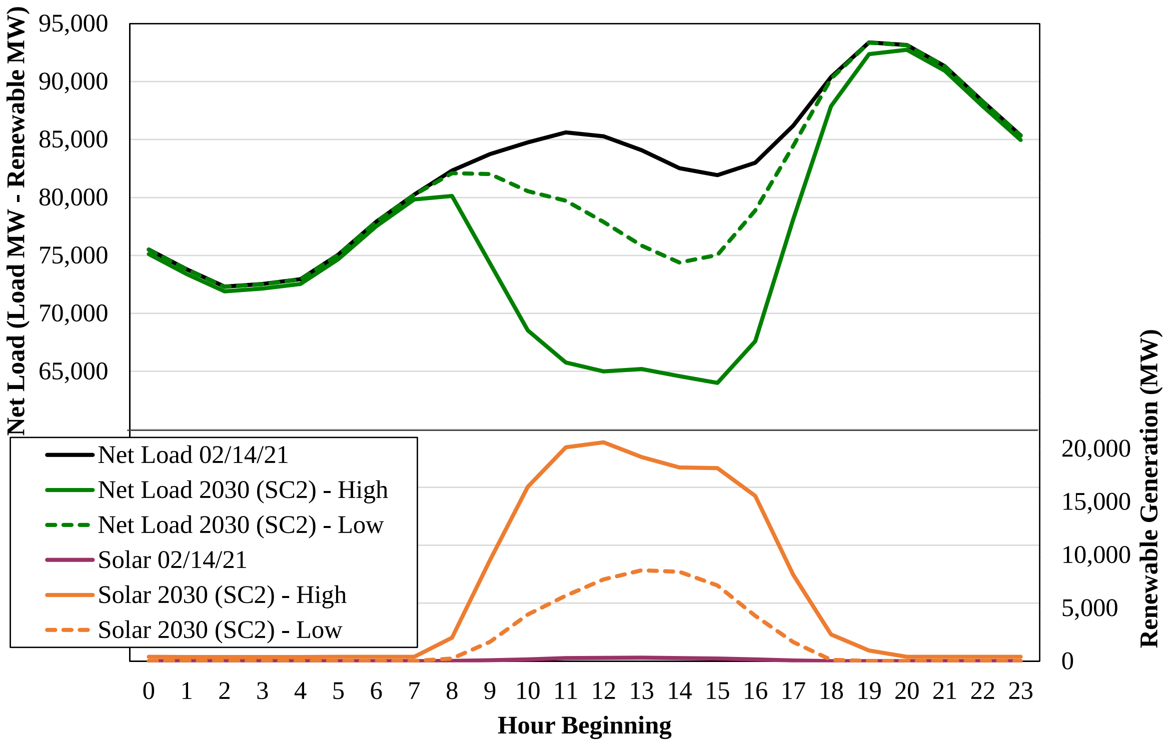
Scenario 1 of Figure 11 above shows that solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years. This expectation is likely driven by the fact that solar resources dominate the interconnection queue, a large share of which may not ultimately enter the MISO market. Nonetheless, the penetration of solar resources will likely be substantial and present new challenges for MISO's operators and its markets. Currently more than 900 MW of solar resources are online in MISO, the vast majority of which entered in 2021.

Given the expected operating profile of solar resources, a large influx of these resources will likely lead to significant changes in the system's ramping needs. Solar resources will not likely contribute to satisfying the morning ramp demands between 6 am and 8 am, which will continue to be served by conventional resources. Once solar resource output spikes in the late morning and through the afternoon, the conventional resources will likely need to ramp down to balance the solar output. As solar output falls off sharply in the evening hours, a second ramping demand of conventional resources will occur. These patterns are particularly challenging in the winter season because MISO's load peaks in the early morning and in the evening when solar output is lowest. These ramp management challenges have already been observed in solar-rich western markets.

Figure 14 shows the "net load" that must be served by conventional resources in MISO under different solar penetration scenarios. 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 the load on a relatively cold winter day—February 14, 2021. Data for modeling solar resources is from the Futures Scenario 2 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 14: Net Load in MISO on a Representative Winter Day



Likewise, the net load increases sharply from 4 pm to 10 pm as the sun goes down. The net load that would be served by conventional resources in this case would rise by more than 25 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.[17]

According to the 2021 OMS DER Survey, 7,243 MW of DER currently exists in MISO, and only 60 percent is registered. Almost a third of this is solar PV, approximately 40 percent is demand response, and the rest is other DER types that include battery storage and small-scale generation. We do not anticipate large-scale entry of DER resources, but MISO should be

17 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).

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 programs or utility rates, wholesale market rules and settlements may result in inefficient incentives to develop and operate the DERs.

In the next subsection, we recommend guiding principles and objectives for MISO's effort to accommodate DERs to address these challenges.

Energy Storage

Order No. 841 required MISO to enable ESRs to participate in the market, recognizing the operational characteristics of ESRs. Figure 11 above shows that MISO forecasts only moderate growth in ESRs over the next decade. Based on the trends we are observing in other markets, we believe this forecast is likely conservative. Installation costs of ESRs are likely to fall as they proliferate. This trend, along with the increases in price volatility discussed above, are likely to cause ESRs to become much more economic in the future. This is particularly true if MISO adopts the shortage pricing improvements described below, which would efficiently compensate them for the value they provide in mitigating or eliminating transitory shortages.

Although it is important to recognize that although ESRs can provide tremendous value in managing the fluctuations in intermittent output and maintaining reliability, ESRs are not a substitute for conventional generation. This is particularly true as the quantities of ESRs rise, which cause the marginal value of ESRs to fall. Therefore, it will be critical to adopt an accurate accreditation methodology for ESRs along with other new technologies 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 change in its future generation portfolio. Fortunately, this is not true. MISO's markets are robust and are fundamentally well-suited to accommodate the transition in MISO's generating fleet, although a number of incremental 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;
- Improving its wind forecasting and incentivizing participants to use MISO's forecasts;
- Modifying its settlement rules to improve generators' incentives to follow dispatch instructions; and
- Proposing reforms to capacity accreditation so that resource capacity credits under Module E match reliability values.

As the resource fleet transitions, some needs may arise that are not currently satisfied by the markets, such as increased needs for voltage support in some locations or system-wide needs for inertial support.[18] We support MISO's continuing evaluation of these issues and will work with MISO to 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 key improvements to the MISO markets discussed in this subsection:

- 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;
- Improvement to shortage pricing to compensate resources that are available and flexible and that allow MISO to maintain reliability when shortages arise;
- Introduction of new processes to optimize the operation of the transmission system and improve its utilization;
- Development of rules and processes for integrating DERs that will satisfy essential reliability and efficiency objectives; and
- Introducing a reliability-based demand curve in the capacity market that will align with the marginal reliability value that capacity provides.

Uncertainty Product and Look-Ahead Dispatch

As MISO transitions to a fleet that is far more dependent on intermittent resources, supply uncertainty will increase markedly, affecting both MISO's planning and operations. MISO has correctly concluded that the availability and flexibility of its non-intermittent resources will be paramount to ensure it can maintain reliability. Figure 15 shows the "net uncertainty" that MISO currently faces in the operating horizon.[19] We calculate the uncertainty typically faced on the system (the 50th percentile) and in the hours when uncertainty is higher (higher percentiles). The figure shows the uncertainty one hour ahead and four hours ahead (blue bars). It also shows the

18 Recent studies have determined that inverter-based resources (IBR) such as intermittent solar and wind, can provide many of the grid-forming benefits provided by conventional resources with the necessary configuration and investment in power electronics. See: https://www.nrel.gov/news/program/2021/landmark-demonstration-shows-wind-turbine-can-provide-fundamental-grid-stability.html.

19 See Section III.B of Analytical Appendix for a detailed description of this analysis.

offline generation available in these timeframes that it can commit to address the uncertainty and the headroom MISO seeks to hold in reserve during ramp hours and during peak hours (green bars). It also shows how frequently MISO commits peaking units in these hours (red diamonds).

Figure 15: Uncertainty and MISO's Operating Requirements
January 2020 to December 2021

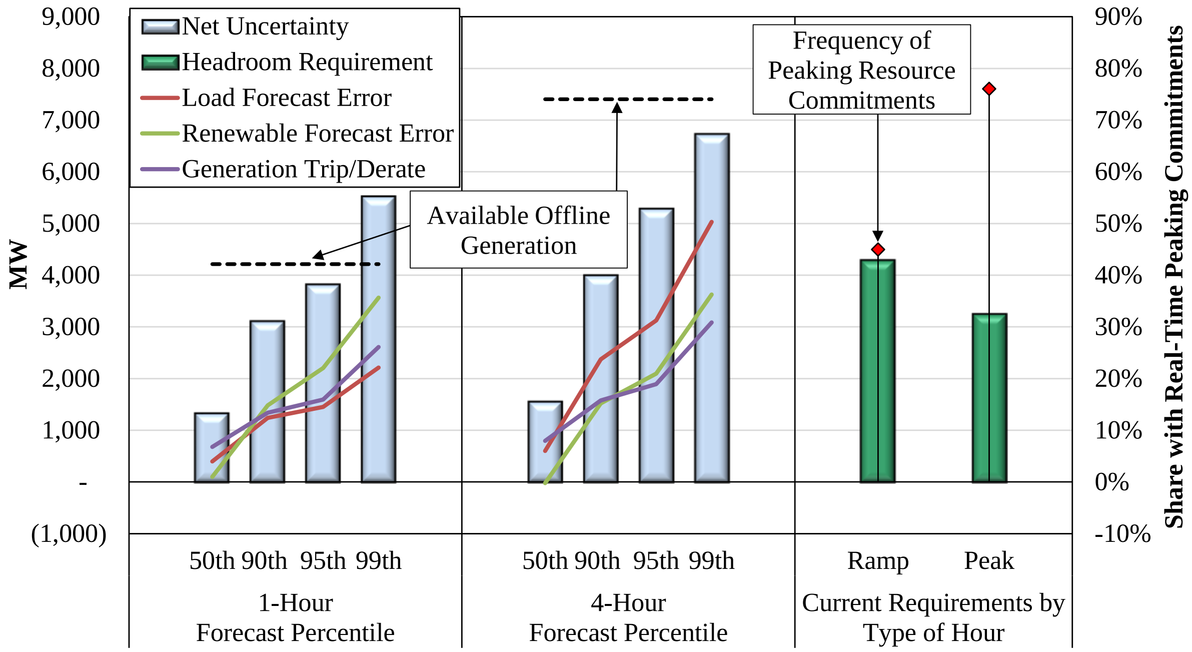


Figure 15 shows that MISO routinely commits resources today outside of the market to ensure it will have sufficient generation available to satisfy the system's needs, including all sources of supply and demand uncertainty. These requirements cause RSG costs to be incurred almost every day. If these requirements were reflected in a market product, prices would more efficiently reflect these requirements, less out-of-market intervention by MISO's operators would be needed, the associated RSG costs would largely disappear.

As the levels of intermittent generation increase, these operational needs and out-of-market costs are likely to rise substantially. Hence, we recommend that MISO develop a spot capacity product for 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. Clearing such a product on a market basis 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.

In the longer term, we recommend MISO consider implementing this product along with other existing products through a look-ahead dispatch and commitment model that would optimize the dispatch of resources in future periods of up to four hours. Adding tools such as a look-ahead dispatch and commitment model will enable more efficient management of increased storage and DERs, which will be important as the penetration of these resource types in MISO grows.

Currently, MISO may not be able to be optimize these types of resources over its current 5-minute dispatch interval.

Shortage Pricing in the Energy and Ancillary Services Markets

Virtually all shortages in energy and ancillary markets are of reserve products (i.e., less reserves will be held than required). 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. The shortage value is established in the reserve demand curve for each reserve product, so efficient shortage pricing requires properly valued reserve demand curves.

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. The output of most renewable resources is intermittent and increases supply uncertainty, which will likely increase the frequency of reserve shortages.

The most highly valued reserve demand curve in MISO is the total Operating Reserve Demand Curve (ORDC). Shortages of total operating reserves are the most severe reserve shortages and the most likely to impact pricing during capacity emergencies. An efficient ORDC should: a) reflect the marginal reliability value of reserves at each shortage level; b) consider all supply contingencies, including multiple simultaneous contingencies; and c) have no artificial discontinuities that can lead to excessively volatile outcomes. The marginal reliability value of reserves at any shortage level is equal to the expected value of lost load. This is equal to the following product at each reserve level:

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

MISO's current ORDC does not efficiently reflect the value of reserves and is based on an understated VOLL. Hence, we recommend that MISO improve its shortage pricing by improving its VOLL and the slope of its ORDC as described below.

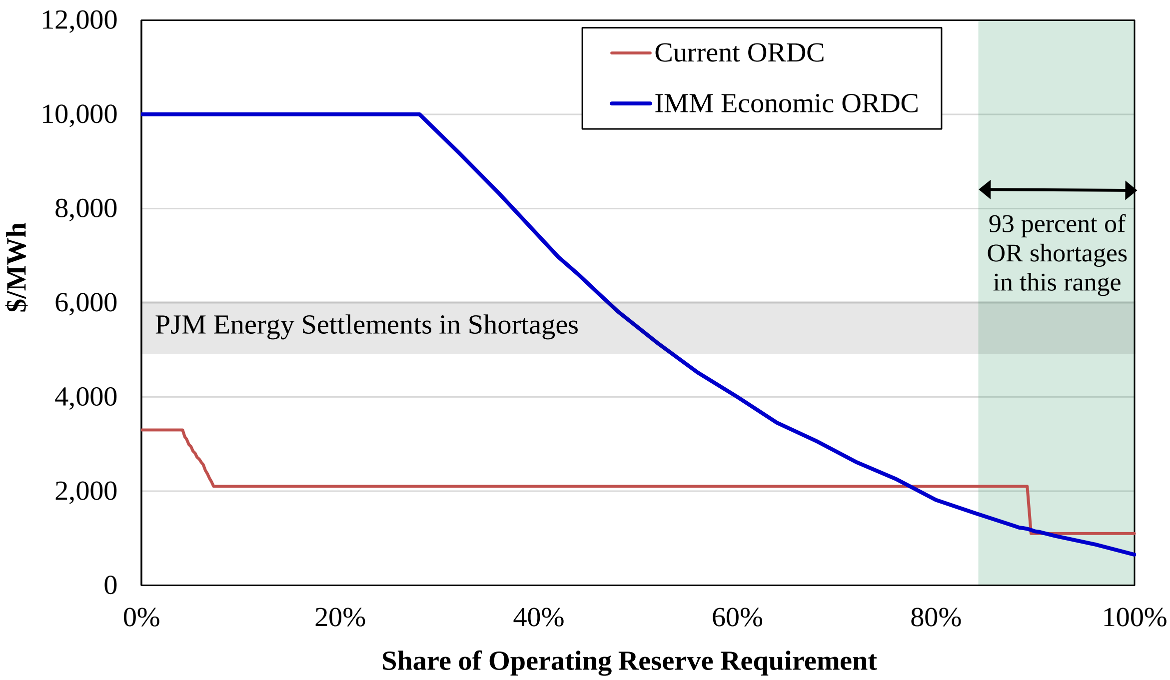
Improving the VOLL. We conducted a literature review and utilized a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. This study, as well as a number of others, estimated a much different VOLL for residential customers and for commercial/industrial customers with the latter being much higher. Using the Berkeley Model and 2018 data for MISO, we estimated VOLL for residential customers ranging from $3,600 to $3,900 per MWh, and for commercial customers ranging from $32,000 and $73,000 per MWh.[20] Weighting these values based on the 2018 load data in MISO yields an average VOLL of $23,000 per MWh. We recommend MISO adopt this VOLL or a comparable value.

20 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 accurately estimating the vast combinations of random contingencies and conditions that could occur when MISO is short of reserves. To model these random occurrences, we estimated the probability of losing load using a Monte Carlo simulation.[21] This simulation includes generation contingencies, wind forecast errors, load forecast errors, and NSI uncertainty. Considering all these factors produces a flatter slope for the ORDC.

The results of our recommended VOLL and improved ORDC slope is reflected in the IMM Economic ORDC that is shown in Figure 16 as the royal blue line. The figure also shows MISO's current ORDC, which is significantly understated for almost all shortage quantities.

Figure 16: Comparison of IMM Economic ORDC to Current ORDC



Our proposed ORDC plateaus at $10,000 per MWh for three primary reasons: (i) very few shortages would be priced in this range as the figure shows; (ii) pricing shortages at prices exceeding $10,000 per MWh could result in inefficient interchange because most of MISO's neighbors price shortages at lower prices; and (iii) pricing at higher price levels could cause MISO's dispatch model to make inefficient trade-offs between retaining reserves and managing flows on network constraints.

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

21 The simulation estimated the conditional probabilities across 10,000 iterations, which is described in Section III.B of the Analytic Appendix.

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 and likely increased distances will occur between load centers and generating resources. These challenges will arise partially because large fluctuations in intermittent output can cause substantial changes in transmission flows, potentially resulting in more erratic and severe congestion patterns that are more difficult to forecast. Additionally, much heavier reliance on intermittent and inverter-based resources may raise issues related to other system attributes that are currently provided by conventional resources, such as inertial support, voltage and current stability, and reactive power.

MISO is actively engaging stakeholders in studying potential future scenarios and challenges to the bulk electric system and grid operations through both the MTEP and RIIA studies. These studies are valuable because they will allow MISO to identify the investments that may be necessary to address these issues. Such investments may include the addition of grid equipment such as synchronous condensers and static VAR compensators that can satisfy system support needs. Incremental investments in the new intermittent resources may also help satisfy some of these needs, so it will be valuable for MISO to evaluate its market incentives and interconnection requirements to facilitate such investments.

At the same time, new technologies and processes may become available that will allow MISO to optimize the operation of the transmission network by redirecting network flows to minimize congestion or by dynamically rating 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" and the processes are referred to as "grid optimization". These are compatible with our recommendation that MISO develop a robust process to implement economic system reconfigurations (See SOM 2021-1). In addition to reducing network congestion, these technologies and processes 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.

In 2020, FERC convened a technical conference to discuss the opportunities and barriers to the utilization of such technologies.[22] 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 market systems. These efforts are likely to be synergistic with integration and utilization of new resource types, including energy storage and DERs. We recommend that MISO anticipate these needs in the near term because the benefits of such improvements are likely to grow substantially as MISO's generating fleet transitions.

22 See Docket No. AD19-19. FERC noted that grid enhancing technologies may include (1) Power flow control and transmission switching equipment; (2) storage technologies; and (3) advanced line rating management technologies. In February 2022, FERC issued an NOI (see AD22-5) on Dynamic Line Ratings that may lead to a rulemaking that would include proposed requirements for enabling and integrating these technologies.

Objectives for Accommodating Distributed Energy Resources

In response to FERC Order 2222, MISO is engaging stakeholders to identify technical, market, and reliability issues associated with alternative DERs. There are a wide range of possible DER models with varying roles between MISO, the LSEs, DER aggregators, and individual DERs. As MISO develops new market rules and processes, it should seek to ensure that DERs will support reliability and provide efficient incentives for DERs and non-DERs. To achieve these two goals, we recommend that MISO address the following primary 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 DERs 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.
- *Account for DERs in the Planning Process*. This includes the use of accurate operational and locational information about DERs that will need to be provided by DER owners.
- *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.

DERs may present new challenges. The evolving rules should provide efficient incentives to be controllable and require visibility and verification. This will be key to integrating DERs reliably.

Reliability-Based Capacity Market Demand Curve

One of the most essential changes to the MISO markets that will be needed to satisfy the Reliability Imperative is reform to the capacity market so it provides efficient economic incentives. These reforms will generally benefit MISO's regulated utilities that have historically shouldered most of the burden of ensuring resource adequacy.

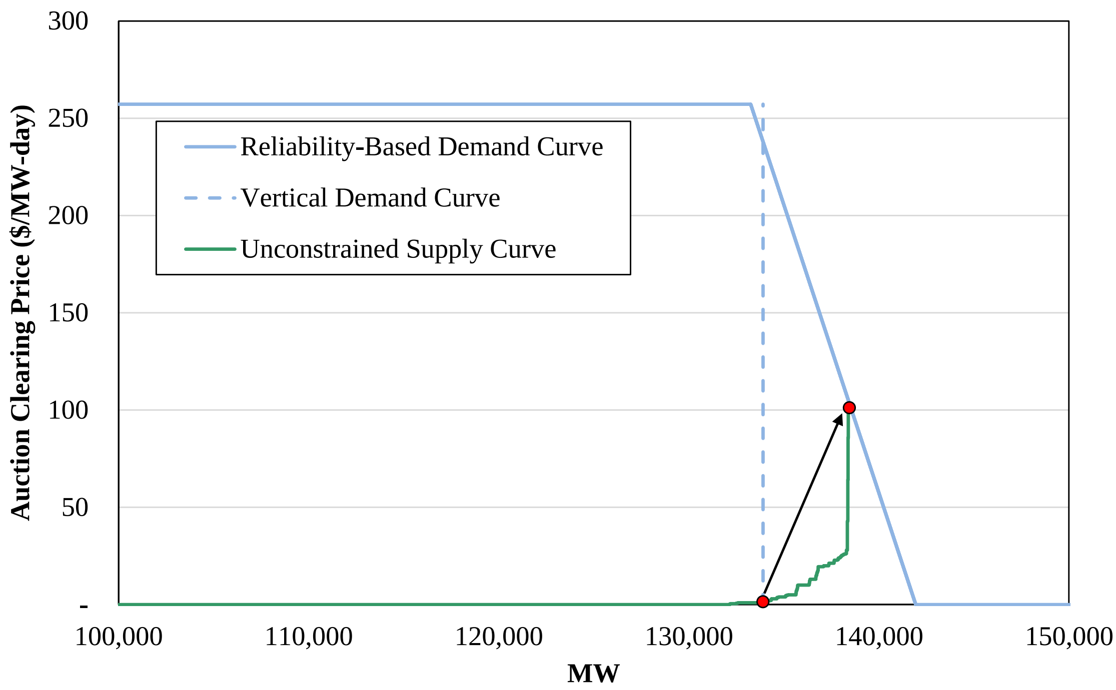
The problem with the current capacity market is that the demand for capacity does not reflect the true reliability value of capacity. The fixed quantity of required demand subject to a deficiency price represents a vertical demand curve for the market. The implication of a vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. In reality, each unit of surplus capacity above the minimum requirement increases system reliability and lowers energy and ancillary services costs, although these effects diminish as the surplus increases.

The true marginal contribution of surplus capacity to reliability can only be captured by a sloped reliability-based demand curve. Implementing a reliability-based demand curve will:

- Establish stable and efficient capacity prices to facilitate efficient market incentives that govern not only new investment decisions, but also resource retirement decisions;
- Ensure that participants supplying more than their share of the required capacity in MISO receive capacity revenues that reflect their contribution to the system's reliability needs;
- Provide incentives for load-serving entities that do not own sufficient capacity to plan efficiently by contracting for existing capacity or building new capacity; and

To demonstrate the significance of this improvement, we simulated the clearing price in MISO that would have prevailed in the 2021/2022 PRA had MISO employed sloped demand curves in the PRA (Appendix Section III.C describes the assumptions underlying this curve). Figure 17 provides a representation of the sloped demand curve for all of MISO. The blue dashed line in the figure represents the vertical demand curve actually used in the auction. The solid green line is the capacity supply curve, reflecting resource offer prices and quantities. Resources that are self-supplied in accordance with Fixed Resource Adequacy Plans are represented with $0 offers.

Figure 17: Supply and Demand in 2021/2022 PRA

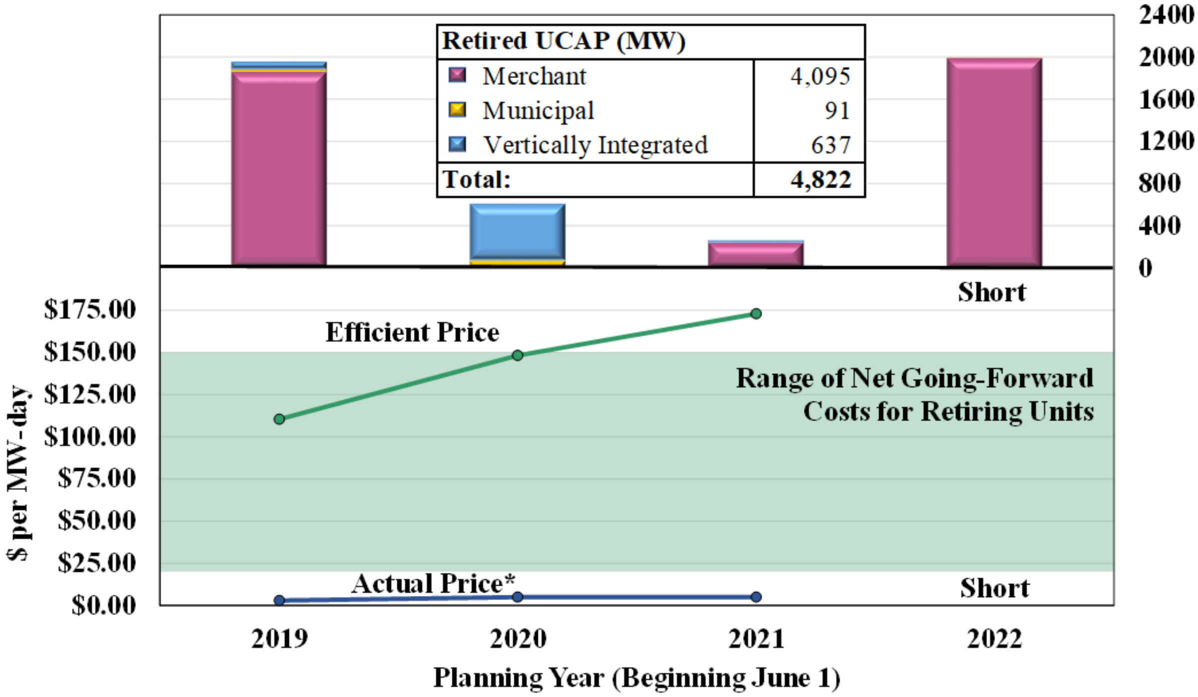


This illustrative example shows that the reliability-based demand curve would have increased prices from close to $0 to $100 per MW-day. In the actual 2021/2022 MISO PRA, prices were close to zero in both subregions. However, because the transfer constraint was binding, prices under a reliability-based demand curve would vary between the subregions, clearing at $150 per MW-day in the Midwest and $13 per MW-day in the South. Although this remains well below the cost of new entry of roughly $250 per MW-day, this price would ensure existing resources that were needed to maintain reliability would remain in operation.

Unfortunately, because the PRA sets prices far below efficient levels (close to zero) by design, our resource adequacy concerns that we have raised for almost 15 years have now materialized. MISO's inefficiently low capacity prices have led to a sustained trend of retirements in recent years. A substantial share of these retiring resources would have been economic to remain in operation had MISO priced capacity efficiently in the PRA.

In the top panel of Figure 18, we show the amount of economic capacity in the Midwest (by type of participant) that retired each year because they did not receive efficient capacity market revenues. The bottom panel shows the range of net going-forward costs that resources would have needed to recover in the capacity auction to avoid suspension or retirement. The actual price in each year's auction is compared to an efficient price that would have prevailed under a reliability-based demand curve. Since the Midwest would have been short in 2022/2023 under any market design, the clearing price would be CONE in the Midwest regardless.

Figure 18: Inefficient Auction Clearing Prices and Associated Retirements
Midwest, 2019–2022



* Actual prices are the unconstrained auction clearing prices of the Midwest. Zone 7 separated in 2019 and 2020.

Figure 18 shows that most of the inefficient retirements over the past four years were made by merchant generators who rely on market signals to make long-term investment and retirement decisions. Captive retail ratepayers subsidize resources owned by vertically-integrated utilities and shield those resources from the inefficient capacity market signals. MISO's poor capacity auction design has driven economic resources into retirement and ultimately led MISO to be short of resources in the Midwest region. These issues are likely to persist unless and until MISO addresses the problems caused by its poor representation of capacity demand.

Short-Term Effects of PRA Reform on Different Types of Participants

The next analysis estimates how improving the design of the PRA would have affected various types of market participants in the 2021/2022 PRA. We calculated the simulated settlements for each participant based on its net sales. We then aggregated the participant-level results into four categories: competitive suppliers (merchant generators), competitive retail LSEs, municipal and cooperative entities, and vertically-integrated utilities. The results are shown in Table 2.

Table 2: Effects of Sloped Demand Curve by Type of Participant
2021–2022 PRA

Type of MP	Net Revenue Increases	Net Revenue Decreases	Total
Vertically Integrated LSEs	$148.4M	-$27.3M	$121.1M
Municipal/Cooperative	$67.2M	-$81.2M	-$14.0M
Merchant	$59.3M		$59.3M
Retail Choice/Competitive LSEs		-$166.4M	-$166.4M

This table shows that the vertically-integrated utilities would have benefited in aggregate by more than $120 million from the use of the sloped demand curve, and 70 percent of participants in that category would have realized almost $150 million in increased revenues. The effects on the vertically integrated utilities were significant because they tend to have surplus capacity. This is because their investments in new generation are often lumpy (i.e., in large increments), and made to ensure they meet their planning reserve requirements. Hence, vertically integrated utilities would realize significant benefits from a sloped demand curve because it would allow them to sell their excess capacity at prices that reflect its value.

While some municipal and cooperative entities also would have benefitted from the adoption of a sloped demand curve in the 2021–2022 auction, on net the costs to municipal and cooperative entities would have increased by $14 million because many of them do not own sufficient resources to meet their own requirements. Improving pricing in the PRA would provide stronger and more efficient incentives for them to plan and contract for resources to satisfy their needs.

The effects on the competitive participants are more important because the economic price signals from the wholesale market guide key decisions by the unregulated participants in MISO, including competitive suppliers and competitive retail LSEs.

- Merchant generators would have received almost $60 million more capacity revenue, providing more efficient signals to maintain existing resources and build new resources. This revenue would have been key in maintaining economic resources that have retired over the past few years that caused MISO to now be short of resources in the Midwest.
- Costs borne by competitive retail load providers would have risen by $166.4 million per year. This is desirable because it provides incentives for these LSEs to arrange for their capacity needs and contribute to satisfying resource adequacy in MISO.

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.[23] The real-time market clears based on actual physical supply and demand and settles any deviations from day-ahead contracts at real-time prices.[24] The performance of both markets is essential.

The performance of the day-ahead market 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;[25]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market—98 percent in 2021 (net of virtual transactions); and
- Entitlements of firm transmission rights are determined by day-ahead market outcomes (i.e., payments to FTR holders are based on day-ahead congestion).

The performance of the real-time market is also crucial because it governs the physical dispatch of MISO's resources to maintain system balance and security, 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 the day-ahead and real-time markets in key areas, as well as how they were operated by MISO.

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, rising substantially in 2021 as natural gas and coal prices increased. Average day-ahead energy prices across MISO increased 82 percent from 2020 to $40.42 per MWh. Congestion caused day-ahead prices at MISO's hubs to range from $36.71 per MWh at the Arkansas Hub to $41.78 per MWh at the Texas Hub.

An important difference between the day-ahead and real-time markets is the day-ahead market is scheduled hourly while the real-time market operates 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

23 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.

24 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.

25 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.

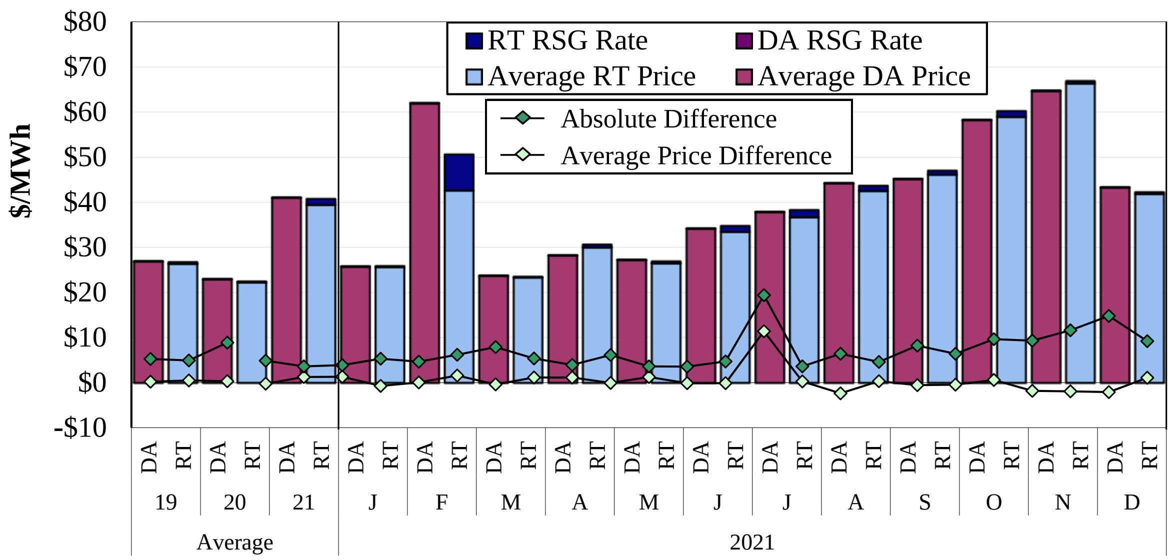
gradually as load and other conditions change over the day. Since large changes in supply tend to occur at the top of the hour when day-ahead schedules change, prices tend to spike at the top of the hour. To improve the operation of the system, we have recommended MISO evaluate the feasibility of transitioning to a 15-minute day-ahead market.

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 19 shows monthly and annual price convergence statistics. The upper panel shows the 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 19: Day-Ahead and Real-Time Prices at Indiana Hub

2020–2021



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

Indiana Hub	1	2	1	0	23	1	-8	1	-2	-1	1	-4	-3	-3	3
Michigan Hub	-1	1	1	0	14	-1	-4	1	-3	0	1	-3	-1	-1	1
Minnesota Hub	1	-2	-1	-1	6	3	-15	-9	-5	1	1	-7	-2	2	0
Arkansas Hub	1	1	-3	3	-14	-3	-6	-1	1	-5	3	-5	-2	5	-2
Louisiana Hub	5	2	-1	1	-14	-10	0	1	2	0	8	-5	3	3	-1
Texas Hub	-1	6	-2	0	-10	-6	0	-2	4	-1	3	-4	2	6	-1

These results indicate that price convergence was good overall. Day-ahead prices were about one percent higher than real-time prices, after adjusting for the real-time RSG costs, which averaged $1.31 per MWh. Divergence between day-ahead and real-time prices occurred primarily because of transient conditions in 2021. The most significant source of divergence occurred following the Winter Storm Uri arctic event in February because MISO committed a significant number of resources in real time. This depressed the real-time prices and generated a large day-ahead premium. In the South, MISO experienced a real-time premium that month because MISO shed load and real-time prices were as high as $3,500 per MWh during the event.

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. As such, virtual day-ahead purchases or sales cannot perform in real time and, therefore, settle against the real-time price. 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 20 shows the average offered and cleared virtual supply and virtual demand in the day-ahead market. The figure is divided between financial-only participants who do not physically participate in the real-time market and physical participants who re-settle physical schedules in real-time.

Figure 20: Virtual Demand and Supply in the Day-Ahead Market
2021

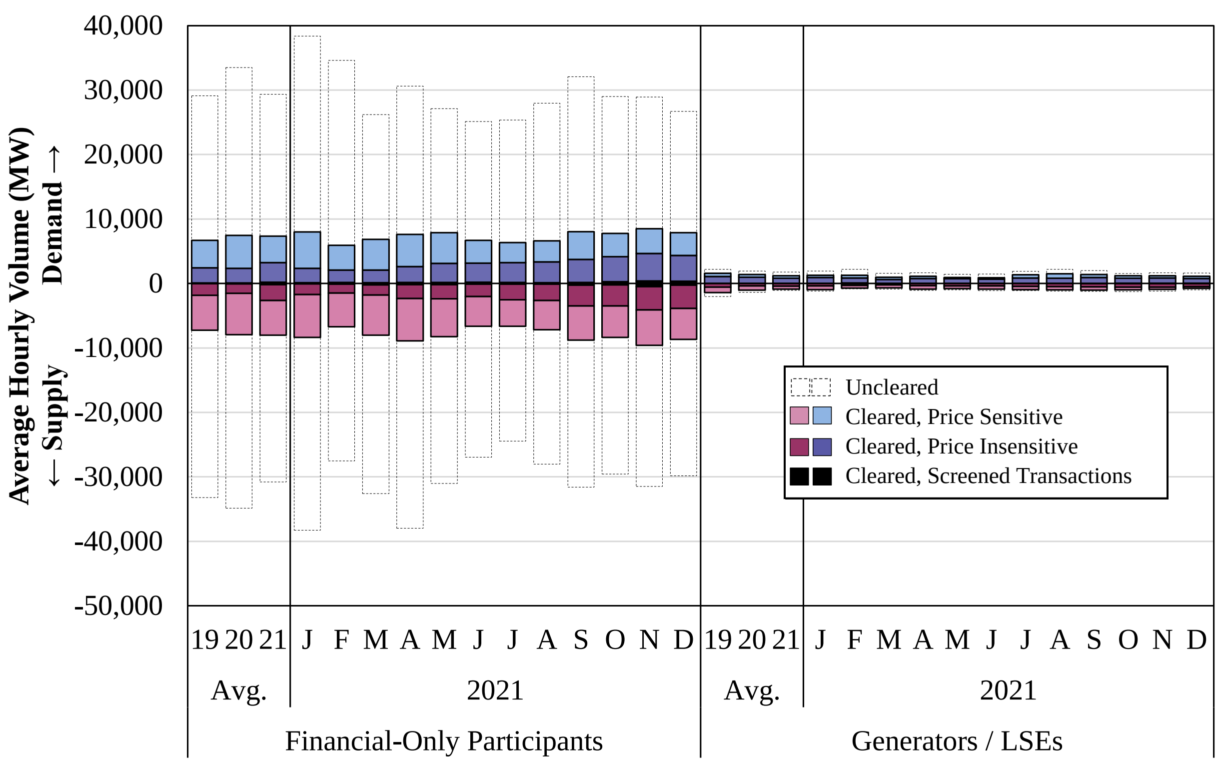


Figure 20 shows that virtual bids and offers by financial participants decreased by 12 percent compared to last year, while virtual bids and offers by physical participants fell 14 percent, driven by a 22 percent decrease in virtual supply offers. Cleared transactions fell 2 percent, despite an increase in price insensitive virtual transactions in 2021. Average cleared virtual transactions in the Midwest increased 4 percent, whereas average cleared virtual transactions in the South fell by 25 percent. This figure indicates the following key findings:

- Financial participants account for the vast majority of the virtual activity in MISO. Financial participants tend to offer more price-sensitively and provide key liquidity to the day-ahead market.
- Several participants submit "backstop" bids, which are bids and offers priced well below (in the case of 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. These transactions are beneficial because they mitigate particularly large day-ahead price movements.
- Bids and offers that are price-insensitive (i.e., offered at prices making them very likely to clear)[26] constitute a significant share of all virtual transactions. They provide liquidity to the market and can raise manipulation concerns.
- Most price insensitive transactions are part of the strategy to arbitrage congestion-related price differences because they allow participants to establish an energy-neutral position between two locations (offsetting virtual supply and demand positions at two locations). This allows them to avoid RSG deviation charges assessed to net virtual supply and to avoid energy price risk. We refer to these transactions as "matched" transactions.
  - The average hourly volume of matched transactions in 2021 increased by 70 percent from 2020 to 1,085 MW.
  - We continue to recommend MISO implement a virtual spread product that would allow participants to engage in such transactions price-sensitively by specifying the maximum congestion between two points they are willing to pay for a transaction. Comparable products exist in both PJM and ERCOT.
- Price-insensitive bids and offers that contribute to a significant congestion *divergence* between the day-ahead and real-time markets raise potential manipulation concerns and labeled "Screened Transactions" in the figure. The screened transactions share was 2.5 percent and did not raise concerns in 2021.

Virtual Activity and Profitability

Gross virtual profitability more than doubled in 2021 to average $1.20 per MWh. Both virtual demand and virtual supply profitability increased substantially. Some of this increase was due to high profits during the Winter Storm Uri arctic event in February. Profitability of virtual demand averaged $4.36 per MWh because of very high real-time prices during emergency conditions on

26 Bids/offers are considered price-insensitive when demand bids are more than $20 above or supply offers are $20 below an expected real-time price (an average of recent real-time prices in comparable hours).

February 15 and 16, while virtual supply profitability averaged $6.89 per MWh because of the sustained day-ahead premium from February 17 to 19.

In general, gross profits are higher for virtual supply because more than half 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 $1.22 per MWh compared to $1.04 per MWh.

To provide perspective on the virtual trading in MISO, Table 3 compares virtual trading in MISO to trading in NYISO, ISO New England, SPP, and PJM.

Table 3: Comparison of Virtual Trading Volumes and Profitability
2021

2021	Virtual Load		Virtual Supply	
Market	**MW as a % of Load**	**Avg Profit**	**MW as a % of Load**	**Avg Profit**
MISO	11.3%	$0.75	11.7%	$1.64
NYISO	6.2%	$0.95	9.7%	$0.10
ISO-NE	2.8%	-$1.29	4.5%	$2.07
SPP	7.5%	$0.64	14.1%	$10.79
PJM	4.8%	$1.45	2.6%	$1.10

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 the more efficient allocation of RSG costs that MISO uses. The table also shows that the liquidity that virtual trading provides in MISO translates to relatively low virtual profits. Virtual supply profits are higher than virtual load because of the RSG cost allocation discussed above.

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 2021. We determined that 58 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 respond to a real-time price trend but overshoot, so they are ultimately unprofitable. 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 Appendix Section IV.G.

Virtual transactions that did *not* improve efficiency led to divergence and were generally those that were unprofitable based on the energy and congestion on modeled constraints. They can be profitable when they profit from un-modeled constraints or loss factor differences. Table 4 shows the total amount of efficient and inefficient virtual transactions by market participant type.

Table 4: Efficient and Inefficient Virtual Transactions by Type of Participant in 2021

	Financial Participants			Physical Participants		
	MWh	Convergent Profits	Rent-Seeking	MWh	Convergent Profits	Rent-Seeking
Efficiency Enhancing (Profitable)	68,042,286	$973.7M	-$16.0M	8,611,112	$107.8M	$6.2M
Efficiency Enhancing (Unprofitable)	10,753,884	-$78.1M	$11.2M	1,589,212	-$10.7M	$2.2M
Not Efficiency Enhancing (Profitable)	3,604,071	-$17.6M	$45.8M	633,169	-$2.2M	$5.3M
Not Efficiency Enhancing (Unprofitable)	52,144,608	-$748.6M	-$6.1M	7,267,925	-$91.2M	$1.4M
Total	**134,544,849**	**$129.5M**	**$35.0M**	**18,101,418**	**$3.7M**	**$15.1M**

The table shows that 58 percent of all virtual transactions were efficiency-enhancing. Convergent profits were positive on net for all virtual transactions by $133.2 million, up from $61.5 million in 2020. 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.

To accurately calculate this total benefit would require one to rerun the day-ahead and real-time market cases for the entire year. However, this analysis allows us to estimate with a high degree of confidence that virtual trading was beneficial in 2021.

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. While the real-time price levels and trends were described in Section II, in this subsection and elsewhere in the report, we evaluate whether real-time prices efficiently reflect prevailing conditions.

One of the most important evaluations in this regard is whether real-time prices during shortages reflect the marginal value of additional reserves and energy. Our discussion of shortage pricing and recommendations for improvements are in Section III.B, which discusses the future needs of the MISO markets. Efficient shortage pricing is perhaps the most important component of the market's ability to perform well and maintain reliability as the fleet transitions to a much heavier reliance on intermittent resources.

Fast-Start 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.[27]

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

Initially, the online component of ELMP had a very small effect on prices, partly because of the limited set of units that were qualified as FSRs and eligible to set ELMPs. MISO implemented changes in 2017 and 2019 to expand the set of eligible FSRs, which has improved the performance of ELMP in setting prices.

MISO implemented another of our recommendations in September 2021 to relax the down ramp rate limit on FSRs dispatched at their economic minimums. Relaxing the ramp rate allowed them to be considered marginal and set prices unless dispatched to zero. Previously, ELMP did not allow resources to set prices when the ELMP dispatch model sought to ramp them down at their maximum ramp rate, which prevented FSRs that were needed to satisfy the system demands from setting prices. Together, these changes have significantly improved real-time price formation in MISO. The following figure summarizes the effects of the ELMP pricing model in 2021.

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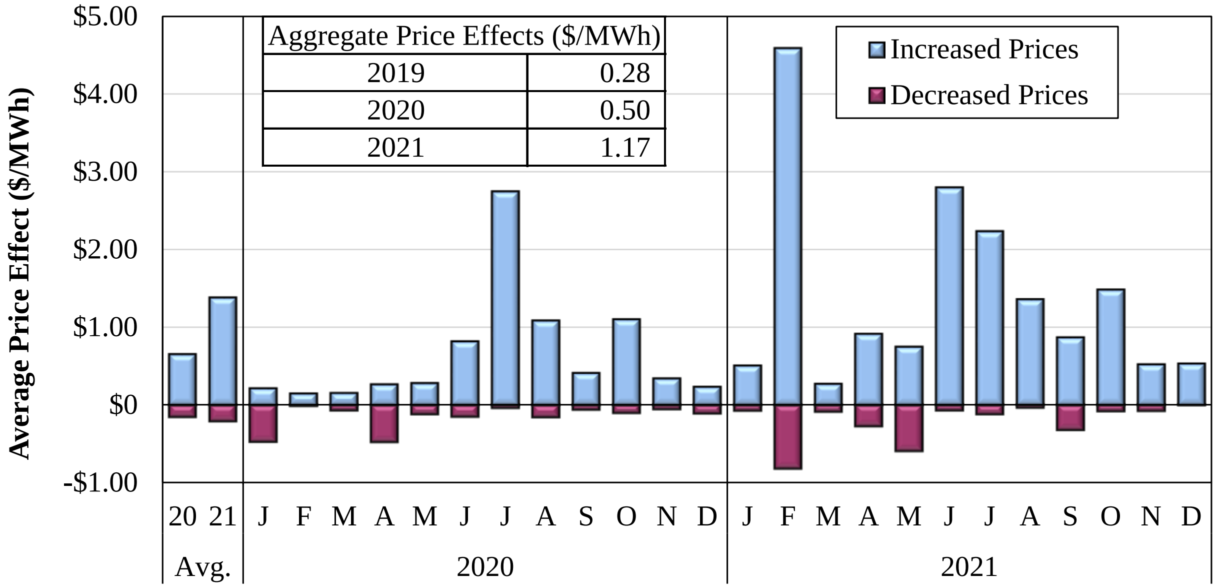
27 MISO had previously allowed offline fast-start resources to set prices under transmission and reserve shortage conditions. Our prior evaluations indicated that this offline pricing was generally inefficient and recommended MISO discontinue it. MISO suspended offline pricing in ELMP in October 2021.

Figure 21: The Effects of Fast Start Pricing in ELMP
2020–2021



% of Intervals Affected by > +/- $0.10

SMP Increase	53	56	46	42	40	49	41	52	88	61	60	71	49	42	36	57	44	61	54	68	61	60	54	66	61	52
SMP Decrease	2	2	1	0	1	2	1	8	1	3	3	3	4	2	3	6	2	3	5	1	1	1	1	1	1	0

As shown in Figure 21, the effects of ELMP on MISO's real-time energy prices rose more than 130 percent in 2021. This increase was due to a combination of the ELMP improvements described above, the high price effects in February, higher natural gas prices, and the elimination of offline ELMP pricing in the fall. We expect ELMP will continue to perform well because of the improvements MISO has made in recent years. As expected, ELMP had almost no effect in the day-ahead market because the supply is much more flexible and includes virtual transactions.

Emergency Pricing by the ELMP Model

In addition to FSRs, emergency actions and resources can set prices in ELMP during declared emergencies. In September 2021, MISO implemented recommended improvements to its ELMP emergency pricing. MISO expanded the set of resources that can set prices during an emergency[28] and established minimums on the Tier 1 and Tier 2 Emergency Offer Floor Prices applied to emergency resources at $500 per MWh and $1,000 per MWh, respectively.[29] In previous years, MISO's emergency offer floor prices were set inefficiently low. MISO updated the value of RPE constraints to $200 per MWh during emergencies. These changes will help ensure that MISO's emergency pricing will set more efficient pricing during emergencies.

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

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

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 them to zero, then they are needed and should set real-time prices. While this is reasonable in most cases, applying this approach to LMRs has not been reliable. The primary problem is the LMRs are usually deployed in large quantities (3 to 6 GWs) and the ELMP model simply 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 not longer needed. This has resulted in:

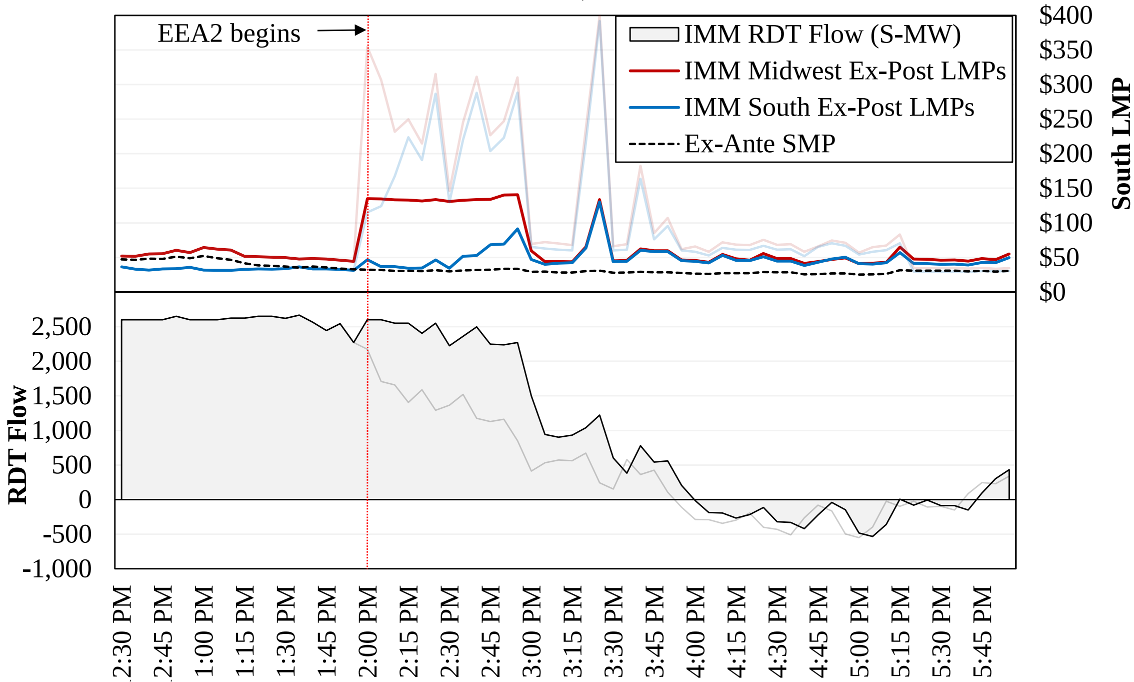
- Excessive non-firm imports as participants respond to the elevated prices;
- High prices extending beyond the emergency area. Once supply is adequate in the tight subregion, the transfer constraint (the RDT) will tend to unbind and the LMRs will set prices throughout the MISO footprint; and
- Large 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. We simulated this solution for the emergency that occurred on June 10, 2021 in the Midwest subregion when MISO committed 3.2 GW of LMRs in the subregion. The results of this simulation are shown in Figure 22 below. It shows the ex ante system marginal prices (not including the emergency pricing) and the ex post LMPs in the Midwest and South (including the emergency pricing). It also shows the RDT flows in the bottom panel.

Figure 22 shows the actual market results in the semi-transparent lines and the simulated results in the opaque lines and areas so the two approaches can be directly compared. Under the current emergency pricing approach, prices were set between $200 and $400 per MWh from 2 pm when the emergency began until roughly 3:30 pm. These sustained high prices resulted in substantial imports that, together with the curtailments, caused the RDT constraint to unbind and the MISO South prices to rise to near the level of prices in the Midwest. The additional supply in the Midwest ultimately caused the Midwest to export energy to the South.

Figure 22 demonstrates significantly improved pricing outcomes resulting from treating LMRs as Short Term Reserves demand in the ELMP pricing model. In this case, while the LMRs were not needed for energy, the model would have shorted STR in the Midwest subregion instead of procuring higher cost energy and reserves from quick-start resources that exceed the $100 per MWh STR demand curve. This results in consistent prices of less than $150 per MWh that better reflects the marginal value of energy in the Midwest during the event. It also produces higher RDT flows that keep the transfer constraint binding and the price in the South efficiently reflecting the adequate supply that existed in that subregion.

Figure 22: Simulated, Proposed EEA2 Pricing and RDT Flows
June 10, 2021



D. 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 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:

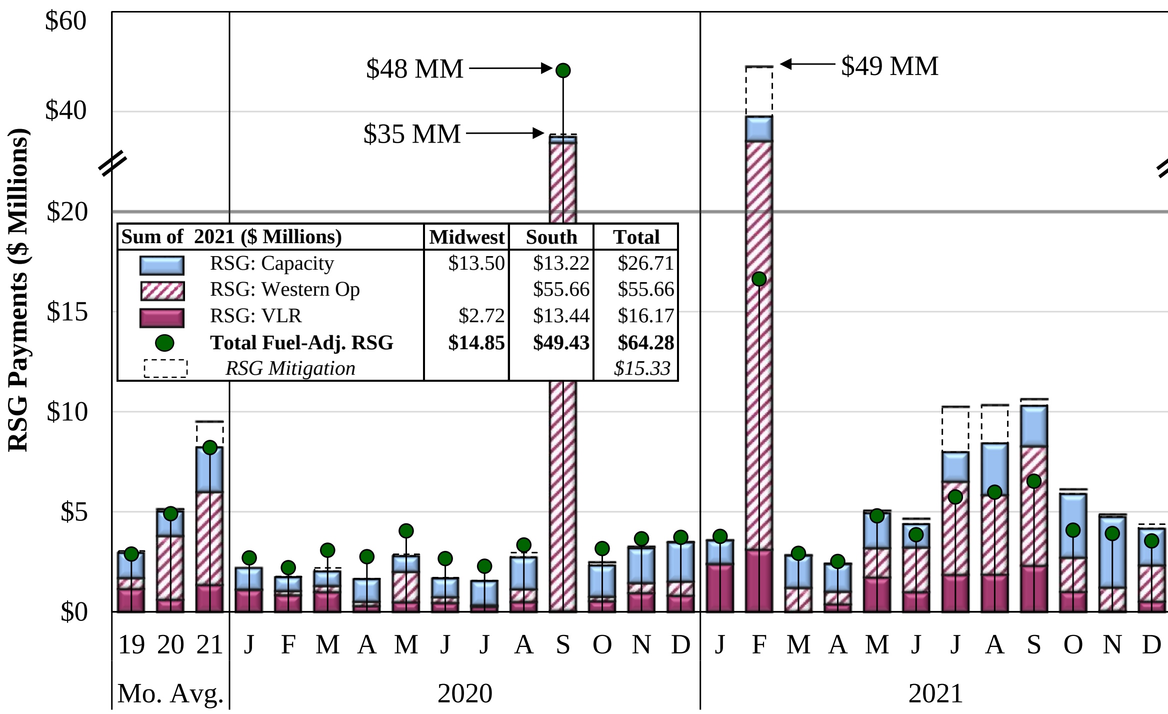
- Revenue Sufficiency Guarantee (RSG) payments ensure the total market revenue for a unit committed economically or for reliability is at least equal to its as-offered costs over its commitment period; and
- Price Volatility Make-Whole Payments (PVMWP) ensure suppliers will not be financially harmed 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 23 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.[30] The maroon bars show all the RSG paid to units started for VLR before the day-ahead market cleared, except the VLR costs incurred for the Western Op Guide. The maroon striped bars show VLR costs incurred to satisfy the Western Op Guide, which maintains adequate transmission capability into WOTAB. The blue part of the bars shows RSG incurred for commitments made to maintain system-wide capacity.

Figure 23: Day-Ahead RSG Payments
2020–2021



Nominal day-ahead RSG payments rose more than 60 percent in 2021 to total $98.5 million. Most of this increase is attributable to high fuel costs and the high RSG incurred during and after the Winter Storm Uri arctic event (almost $40 million). As in previous years, almost all day-ahead VLR costs are accumulated in two load pockets in MISO South. Between May 2019 and January 2021, three new gas-fired combined-cycle units exceeding 3 GW in total came online in MISO South, which should reduce the need for VLR commitments in that region.

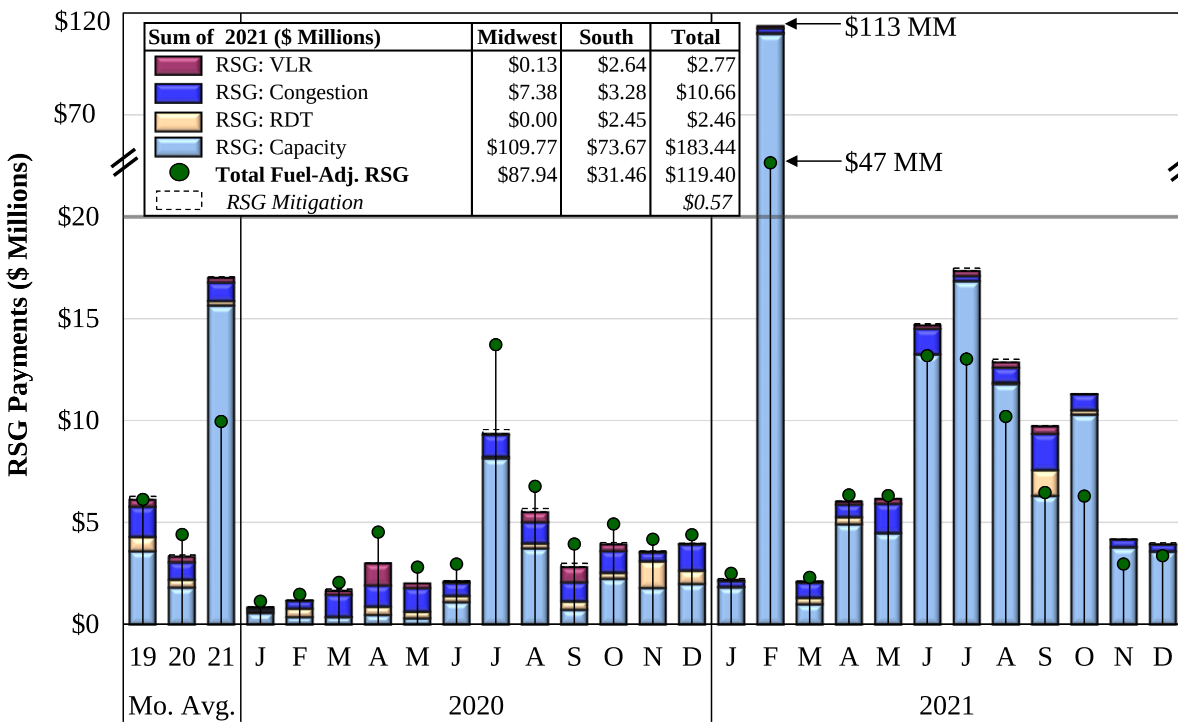
However, even with the addition of those units in the load pockets, average monthly VLR more than doubled in 2021, excluding the anomalous costs incurred during and after Hurricane Laura.

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

Notably, average monthly VLR payments nearly quadrupled in the South during the summer months as MISO committed more expensive gas units for the Western Load Pocket operating guide. Unfortunately, this operating guide was not updated in a timely fashion to reflect the reliability impacts of the new resources in MISO South, including a resource larger than one gigawatt that entered in the Western Load Pocket at the beginning of 2021. We have encouraged MISO to work with its members to implement timely updates to the operating guides in advance of known topology and generation changes.

Figure 24 shows the monthly real-time RSG payments in the same categories as in the day-ahead RSG figure, although it also includes RSG payments for: a) units committed after the day-ahead market to manage flows on a constraint (congestion), and b) units committed after the day-ahead market to manage RDT flows or create regional reserves (headroom) to be able to respond to subregional contingencies without overloading the RDT.

Figure 24: Real-Time RSG Payments
2020–2021



The figure shows that real-time nominal RSG payments rose more than 400 percent in 2021. A large share of this increase occurred during and after Winter Storm Uri. MISO incurred roughly $125 million during that event, which is discussed in detail in Section II.E. Although fuel prices contributed to the increase, real-time RSG more than doubled in 2021 after adjusting for changes in fuel prices. This indicates that commitment patterns played a key role in the RSG increase.

Therefore, we evaluate and discuss the resource commitments in the next subsection. As discussed in Section II.D, MISO implemented a Short-Term Reserve (STR) product at the end of

2021. Among other things, we proposed the STR to reduce manual VLR commitments by satisfying these requirements through a market-based product. To achieve this objective, we recommend MISO define local STR requirements in the VLR areas.

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. These payments 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 5 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 during Winter Storm Uri in February 2021.

Table 5: Price Volatility Make-Whole Payments
2020–2021

	DAMAP		RTORSGP		Total	Avg. Market-Wide Volatility	Avg. Locational Volatility
	Midwest	South	Midwest	South			
2021	$32.9 MM	$14.2 MM	$4.0 MM	$2.1 MM	$53.3 MM	13.4%	14.3%
*	$6.5 MM	$6.9 MM	$0.0 MM	$1.3 MM	$14.7 MM		
2020	$23.2 MM	$4.5 MM	$1.8 MM	$0.5 MM	$30.0 MM	14.3%	19.2%
2019	$20.3 MM	$6.5 MM	$1.9 MM	$0.5 MM	$29.2 MM	10.9%	13.7%

*** Arctic Event in 2021.**

PVMWP rose 78 percent in 2021 from 2020. As with RSG, a large portion of the DAMAP occurred in February 2021 when prices reached $3,500 per MWh for several hours during load shed conditions. Table 5 shows that the overall PVMWP levels increased by 29 percent in 2021 excluding the extraordinary PVMWP levels that occurred during the Arctic Event. Most of the remaining increase was due to higher energy prices that resulted from higher fuel prices.

E. Real-Time Commitment Patterns

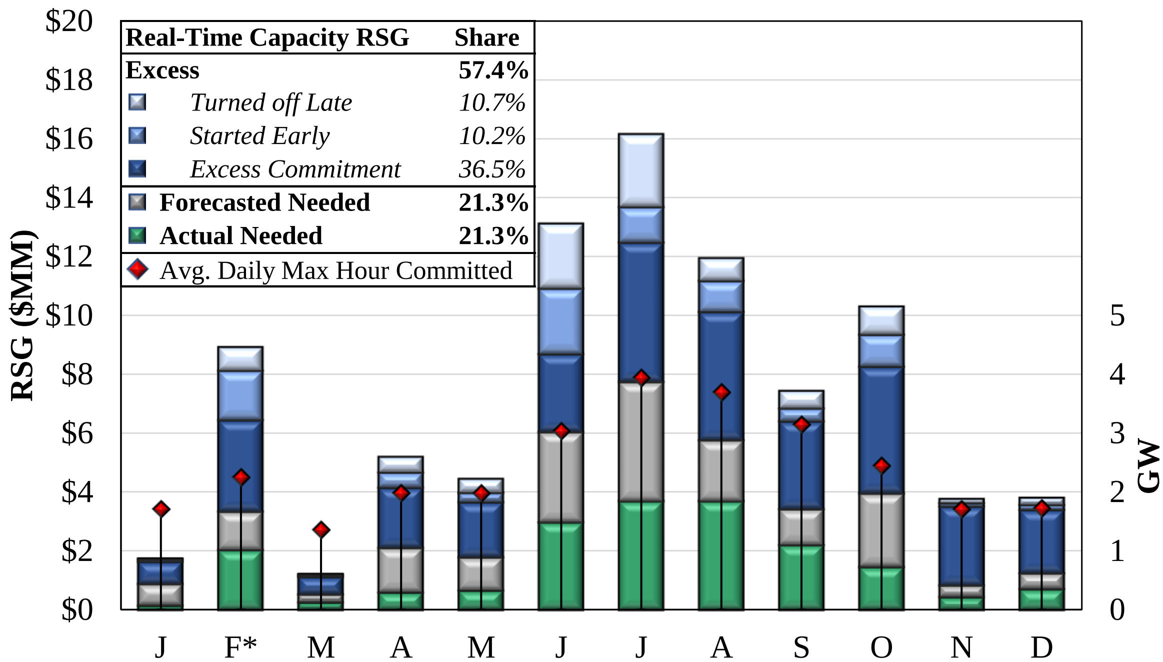
Excluding the very high RSG payments incurred during the arctic event, the fuel-adjusted RSG payments still increased in 2021 by 69 percent. We identified a pattern of increasing capacity-related commitments beginning in the summer months. During the summer quarter, MISO's day-ahead and real-time RSG payments more than doubled over the prior year. Over $38 million in RSG costs were incurred in the Midwest, and more than 40 percent of that occurred on just 10 days. In Figure 25, we show monthly RSG costs in 2021 for resources committed in real time for capacity. We have evaluated these costs and categorize them as follows:

- RSG costs from commitments that were actually needed to cover load and reserves;

- RSG costs from commitments not need but that MISO forecasted as needed; and
- RSG costs from excess commitments that were not needed based on actual load or forecasted load.

The figure also shows the monthly GW average of the daily maximum commitment.

Figure 25: Monthly Real-Time Capacity Commitments and RSG costs in 2021



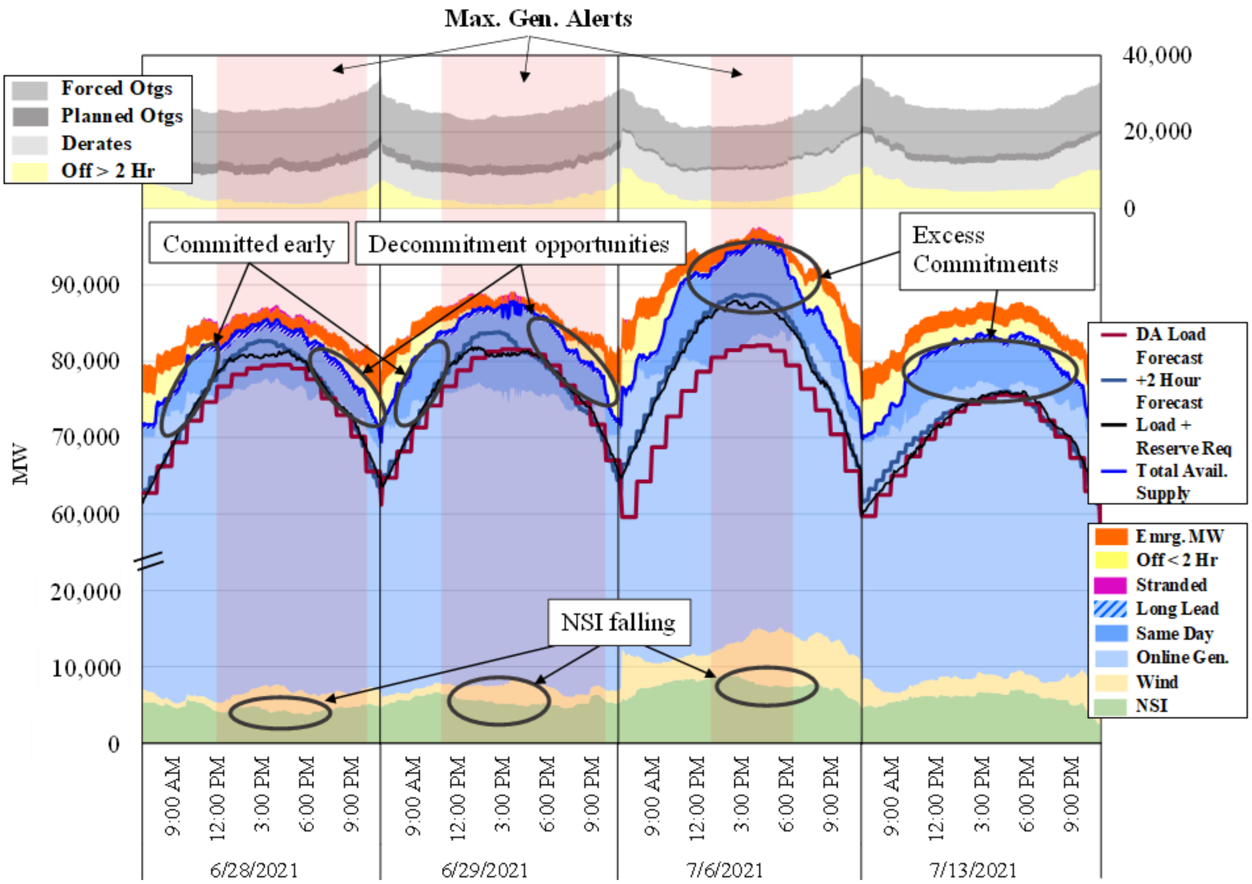
*$102 MM of RT Capacity RSG is excluded for Feb. 13-19, of which 43% was needed.

For purposes of this evaluation, we accept the commitment criteria and capacity requirements that MISO employs, including its headroom targets for the entire footprint and the subregions, although we believe there could be improvements in how these requirements are set. Nonetheless, accepting these requirements and targets, our evaluation finds that:

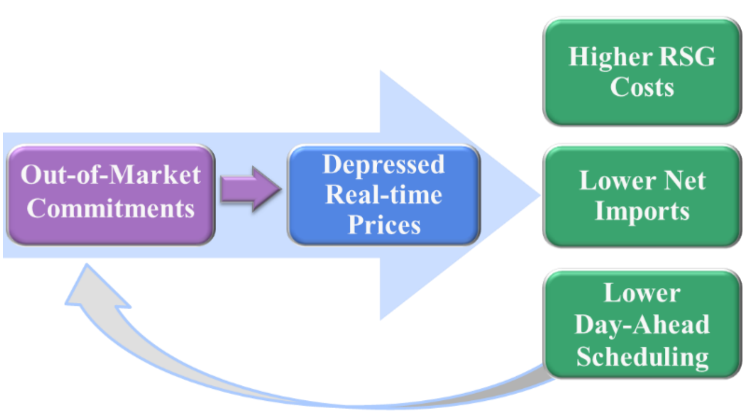
- Roughly 21 percent of the capacity-related RSG costs were actually needed, while another 21 percent appears to be needed when the commitment decision is made.
- 57 percent of the capacity-related RSG costs were associated with commitments that were not needed or forecasted to be needed when they were made (i.e., excess). Some of this excess was not needed entirely while more than a third is associated with resources being started earlier than needed or not being decommitted when no longer needed.
- These excess portions are higher than in prior years as MISO's commitment patterns became noticeably more conservative after the first quarter of 2021. In 2021, MISO's commitments for capacity were 60 percent higher than in 2020.

These results raise substantial concerns not only because of the costs they generate, but more importantly for the secondary adverse effects they have on MISO's market outcomes. Therefore, it is important to identify and address the causes of the over-commitments. In this regard, it is useful to examine days that account for the highest RSG costs. Of the $38 million in real-time RSG costs incurred in the Midwest in the summer, 41 percent were paid for commitments in just 10 days. We show four of the highest-RSG cost summer days in Figure 26, which accounted for more than $9 million of RSG costs. This figure shows the supply and demand conditions in the Midwest subregion during the peak 12 hours of each of these days.

Figure 26: High RSG Cost Days in Summer 2021



This figure shows that many of these resources were committed earlier than needed and not decommitted after they were no longer needed. Additionally, MISO committed in larger quantities than needed on all of these days. On June 28, June 29 and July 6, MISO declared Maximum Generation Alerts in the Midwest and generated more than $2.5 million in RSG costs on each day.



Excess out-of-market commitments undermine the performance of the markets by creating a self-enforcing cycle of excess commitments. As this illustration shows, they depress real-time prices, which increase RSG costs and reduces supply – increasing the need for out-of-market commitments. The lower real-time prices: a) decrease net supply scheduled in the day-ahead market (averaging 98 percent of peak real-time load in 2021), and b) reduce net imports in the real-time market.

We have been working with MISO to improve real-time commitment practices to reduce excessive commitments and prevent price suppression. We have suggested that MISO:

- Allow 30-minute offline units to satisfy real-time capacity needs since they provide almost equivalent reliability value when offline as online.
- Defer commitments that do not need to be made immediately given resources' start-up times and decommitting them when no longer needed.
- Remove the real-time capacity (or headroom) requirements since STR replaces the need for headroom requirements.
- Address multiple uncertain factors probabilistically, rather than attempting to position the system to respond the worst outcome for each factor simultaneously.

MISO has created a Tiger Team to evaluate existing tools and operator practices to improve commitment practices and reduce real-time RSG costs. Improving operator logging is important because it will facilitate better understanding of the causes of excess commitments.

F. Regional Directional Transfer Flows and Regional Reliability

Since the integration of the South into MISO, the transfers between the South and Midwest have been limited to 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 at an average of 250 MW below its contractual limit. Flows on the RDT averaged 560 MW in the South to North direction in 2021 but flows across the RDT were generally correlated with wind output. 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 that MISO explore more direct coordination and settlements on the constraints in adjacent areas that are affected by the transfers. This would increase MISO's ability to move power between the subregions while reduce the congestion effects on its neighbors.

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.

MISO frequently commits resources out-of-market to maintain sufficient reserves in each subregion. These actions result in RSG and congestion management costs. To allow the market to satisfy these needs, we recommended that MISO introduce a 30-minute reserve product that MISO implemented in December 2021.

G. 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. We have recommended a number of settlement rule changes to improve these incentives that MISO has implemented.[31] Nonetheless, it is important to continue to monitor generator performance, which we summarize in Table 6. This table shows the average sixty-minute and five-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 6: Average Five-Minute and Sixty-Minute Net Dragging
2017–2021

	5-min Dragging		60-min Dragging		Worst 10%	
	Ramp Hours	All Hours	Ramp Hours	All Hours	Ramp Hours	All Hours
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
2018	595	563	991	851	1,305	1,216
2017	531	509	1,019	876	1,411	1,298

Table 6 shows that the average 60-minute dragging amount had been highest in the morning and evening ramp hours, but performance in these hours is now comparable to performance in other hours. It shows that the 60-minute dragging in all hours increased slightly (5 percent) from 2020 to 2021. Although it has not become markedly worse, dragging raises a substantial concern because capacity on resources that are not following dispatch instructions is effectively unavailable to MISO. Almost 20 percent of the 60-minute deviations are scheduled in MISO's look-ahead commitment model. This is troubling because MISO operators do not perceive this effective loss of capacity and, therefore, may not make economic or needed commitments.

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 there is not physical cause for the derating. We have identified such cases, and MISO has imposed physical withholding sanctions.

31 Most notably, MISO modified its tolerance bands for uninstructed deviations (i.e., deficient energy and excessive energy) and changed its PVMWP rules to adjust the payment based on the generators' performance. These changes have significantly improved the performance of MISO's generators.

These findings indicate the importance of continuing to seek means to improve generators' incentives and the timeliness and accuracy of suppliers' updates to their real-time offers.

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 increase 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 believe 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 sometimes mute legitimate shortage pricing. MISO utilizes a tool that recommends offset values. We are concerned about some of the logic and calculations underlying these recommendations, which have sometimes led to poor offset selections. In response to these concerns, MISO has made some changes and agreed to work with us to resolve other concerns.

H. Coal Resource Operations

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 than in 2020. 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. 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.

This table shows that coal resources were much more profitable than in recent years—their net revenue in excess of their operating costs rose to $14 - $15 per MWh. As described above, this resulted in more frequent starts and higher output levels through the summer of 2021 until fuel limitations and other supply chain issues compelled many coal resources to begin conserving coal and running less. As MISO's IMM, we consulted with many coal resource owners to establish reference levels that accurately reflect these limitations.

Table 7: Coal-Fired Resource Operation and Profitability
2016–2021

	2016-2018			2019-2020			2021		
	Annual Starts	% of Starts	Net Rev. ($/MWh)	Annual Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)
Regulated Utilities	1775		**$6.32**	1630		**$2.47**	1718		**$13.97**
Profitable Starts	1585	89%		1327	81%		1562	91%	
Offered Economically	*757*	*43%*		*635*	*39%*		*885*	*52%*	
Must-Run and profitable	*828*	*47%*		*692*	*42%*		*677*	*39%*	
Unprofitable (Must Run)	189	11%		303	19%		156	9%	
Merchants	178		**$7.55**	159		**$4.64**	124		**$14.93**
Profitable Starts	170	95%		159	100%		124	100%	
Offered Economically	*94*	*53%*		*157.5*	*99%*		*124*	*100%*	
Must-Run and profitable	*76*	*43%*		*1.5*	*1%*		*0*	*0%*	
Unprofitable (Must Run)	8	5%		0	0%		0	0%	

Table 7 also shows that the share of resources running profitably increased significantly in 2021. This was likely due in part to the increasing energy prices, but also likely due to MISO's regulated utilities beginning to offer their resources economically more often and forcing them to start and run as "must-run" resources less often. This is an encouraging trend and is more consistent with the operating practices of MISO's unregulated merchant generators that always offered economically in 2021 and ran profitably in 100 percent of their run hours.

I. Wind Generation

As discussed in Section III.A, wind capacity is continuing to grow in MISO. It now accounts for nearly 29 GW of MISO's installed capacity and produced 13 percent of all energy in MISO in 2021. 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 forecasting, which are summarized in Table 8, showing:

- Average real-time wind output compared to the wind scheduled in the day-ahead market;
- The average hourly output and the top five percent of hourly output by season; and
- The average real-time forecast error and the absolute value of the real-time forecast errors where positive and negative errors do not offset one another.

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

	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.
2021	9.2	8.0	-13.0	10.0	7.0	10.7	18.6	15.3	19.9	5.6%	10.5%
*%**	*14%*	*22%*		*19%*	*9%*	*12%*	*16%*	*11%*	*14%*		
2020	8.1	6.6	-19.3	8.4	6.4	9.5	16.1	13.9	17.4	4.6%	10.3%
2019	6.5	5.5	-15.9	7.2	4.7	7.5	14.4	11.4	14.6	2.7%	8.7%
2018	5.7	5.0	-13.4	6.9	4.2	6.1	13.7	10.1	13.1	NA	NA

Note 1: 2019 Forecast Error calculated for 7/10-12/31.
Note 2: %* Change between 2021 and 2020.

Wind Output Trends

Average wind output has been growing rapidly, increasing 14 percent from last year and 61 percent over the past three years. 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. Both the average seasonal output and the output in the highest wind hours have been consistently rising over the past three years. We expect this trend to continue given the new wind projects in MISO's interconnection queue and the state and federal incentives available to wind resources.

Wind Forecasting

The sharp rise in wind output 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 plays a key role in managing these challenges. The wind forecasts are important because MISO uses them 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. Wind suppliers can submit their own forecasts or rely on MISO's forecasts, which we discuss below.

MISO's Wind Forecasts. In 2017, we identified significant concerns that many wind suppliers were over-forecasting their real-time wind output. MISO implemented critical recommended changes in settlement rules that caused most suppliers to transition to rely on MISO's wind forecast in 2019. This was a significant improvement, but MISO's methodology resulted in a significantly biased forecast as well. We recommended a methodological improvement that MISO implemented in early 2020 that greatly reduced the bias. Table 8 shows that the forecasts are still biased (averaging 5.6 percent) and the absolute value of the errors remains material. Hence, we encourage MISO to evaluate changes to further improve its forecast accuracy.

Market Participant Forecasts. Some of the bias and the remaining errors is due to a small number of wind suppliers that continue to submit much less accurate forecast than MISO's forecast. MISO modified its Tariff to clarify that submitting intentionally inaccurate forecasts is a violation of the MISO Tariff. We monitor for this conduct on an ongoing basis and these Tariff changes should improve our ability to enlist FERC enforcement to deter it.

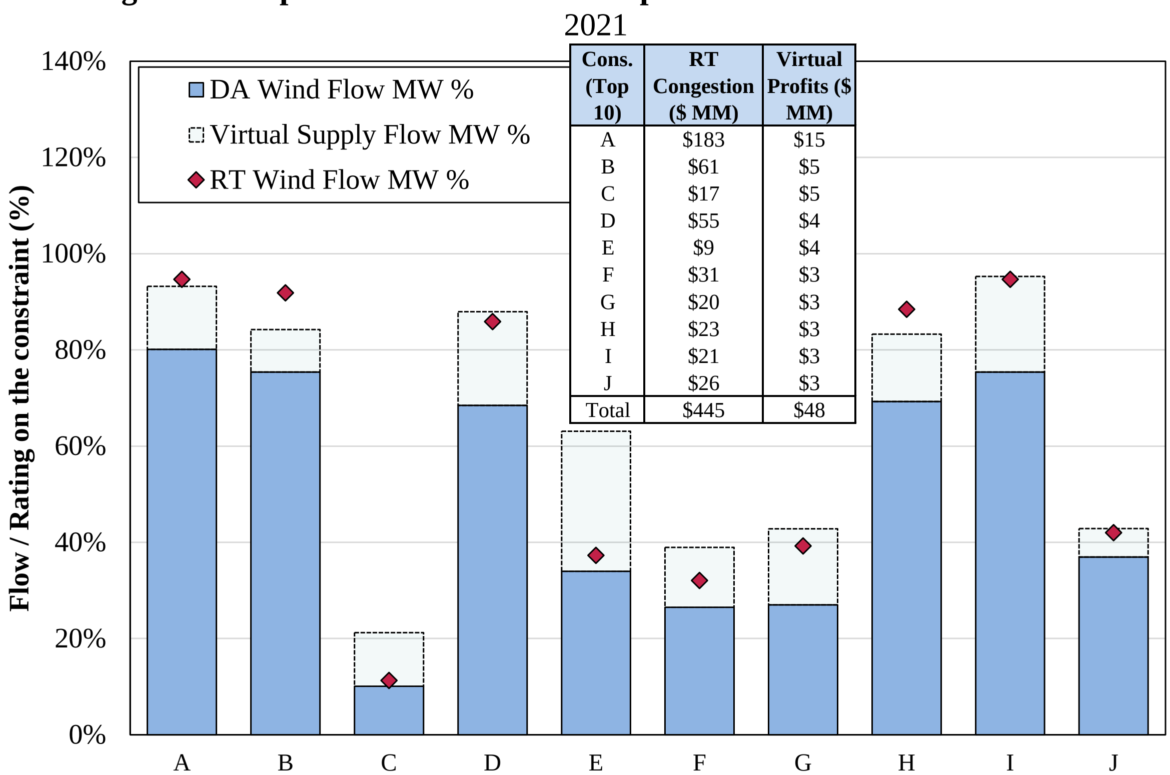
Wind Scheduling in the Day-Ahead Market

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. 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 issues and uncertainty regarding the need to commit other resources.

This convergence issue 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 of 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 the wind under-scheduling. We identified constraints where more than 20 percent of the real-time flows were due to wind generation, and we determined the extent to which virtual transactions bridged the gap in wind under-scheduling.

In Figure 27, we show the day-ahead flow from wind generators in the blue bars, the real-time flow from wind generators in the red diamonds, and day-ahead virtual flow as a transparent bar on top of the blue bar. These values are expressed as a percentage of the rating of the impacted constraints. We show the top 10 constraints and masked the constraint names.

Figure 27: Top 10 Profitable Virtual-Impacted Wind-Related Constraints



Cons. (Top 10)	RT Congestion ($ MM)	Virtual Profits ($ MM)
A	$183	$15
B	$61	$5
C	$17	$5
D	$55	$4
E	$9	$4
F	$31	$3
G	$20	$3
H	$23	$3
I	$21	$3
J	$26	$3
Total	$445	$48

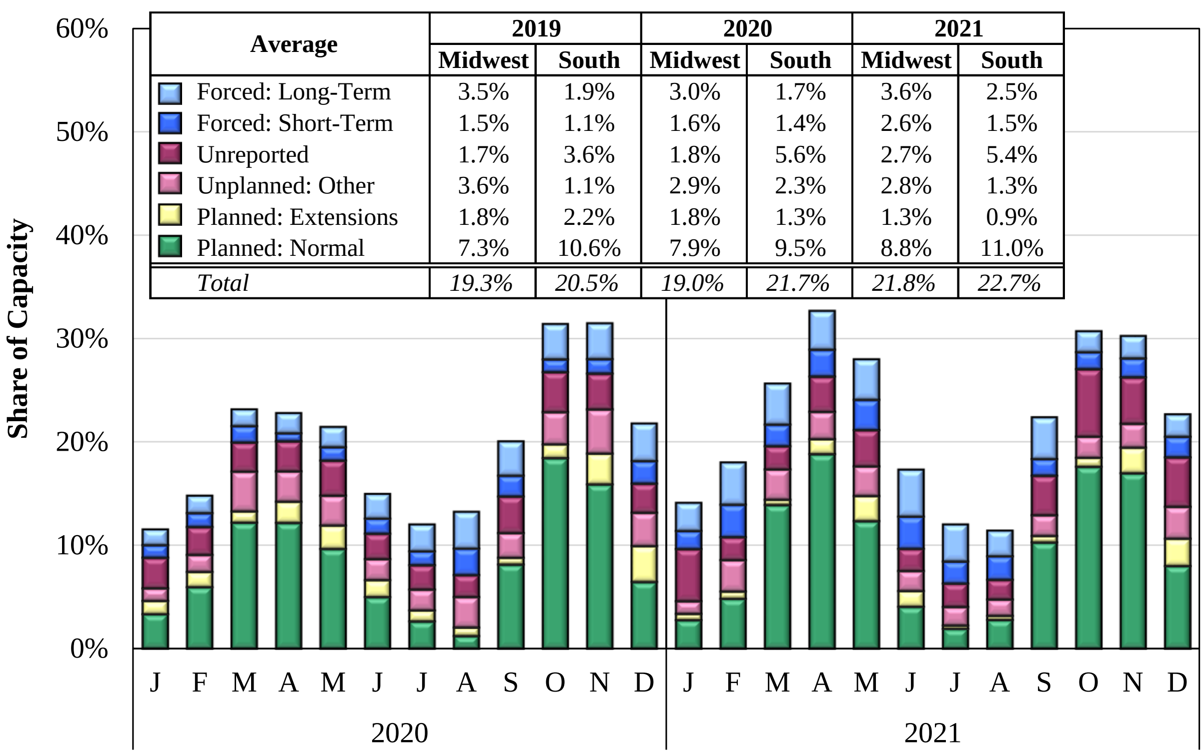
Figure 27 shows that virtual transactions substantially offset the network flow effects of the day-ahead underscheduling by wind resources. These transactions were generally profitable and contributed to the converence of day-ahead and real-time congestion on these constraints. Virtual suppliers made approximately $87 million on a total of 319 wind-impacted constraints, with more than 55 percent of the profits occurring on the ten constraints shown in the figure. The virtual activity serves a valuable role in facilitating more efficient day-ahead scheduling.

J. Outage Scheduling

Proper coordination of planned outages is essential to ensure that enough capacity is available to meet load if contingencies or higher than expected load occurs. MISO approves all planned outages that do not violate reliability criteria but otherwise does not coordinate outages. This lack of coordination raises significant economic concerns and reliability risks. To evaluate the outages that occurred in 2021, Figure 28 shows MISO's outage rates in MISO Midwest and MISO South between 2019 and 2021 in the inset table and from 2020 and 2021 in the bars.

Figure 28 shows that outage rates in 2021 were slightly higher than in 2020 and 2019. During the spring of 2020, more than 20 GW of planned outages were postponed or cancelled because of COVID issues. Planned outages increased in 2021 to more typical levels. As in prior years, true planned outages were relatively low for most of the summer.

Figure 28: MISO Outages
2020–2021



Average	2019 Midwest	2019 South	2020 Midwest	2020 South	2021 Midwest	2021 South
Forced: Long-Term	3.5%	1.9%	3.0%	1.7%	3.6%	2.5%
Forced: Short-Term	1.5%	1.1%	1.6%	1.4%	2.6%	1.5%
Unreported	1.7%	3.6%	1.8%	5.6%	2.7%	5.4%
Unplanned: Other	3.6%	1.1%	2.9%	2.3%	2.8%	1.3%
Planned: Extensions	1.8%	2.2%	1.8%	1.3%	1.3%	0.9%
Planned: Normal	7.3%	10.6%	7.9%	9.5%	8.8%	11.0%
Total	*19.3%*	*20.5%*	*19.0%*	*21.7%*	*21.8%*	*22.7%*

In our 2016 SOM 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. MISO has developed reports to assist participants in coordinating planned outages based on forecasted capacity margins, but our concerns regarding outage scheduling remain.

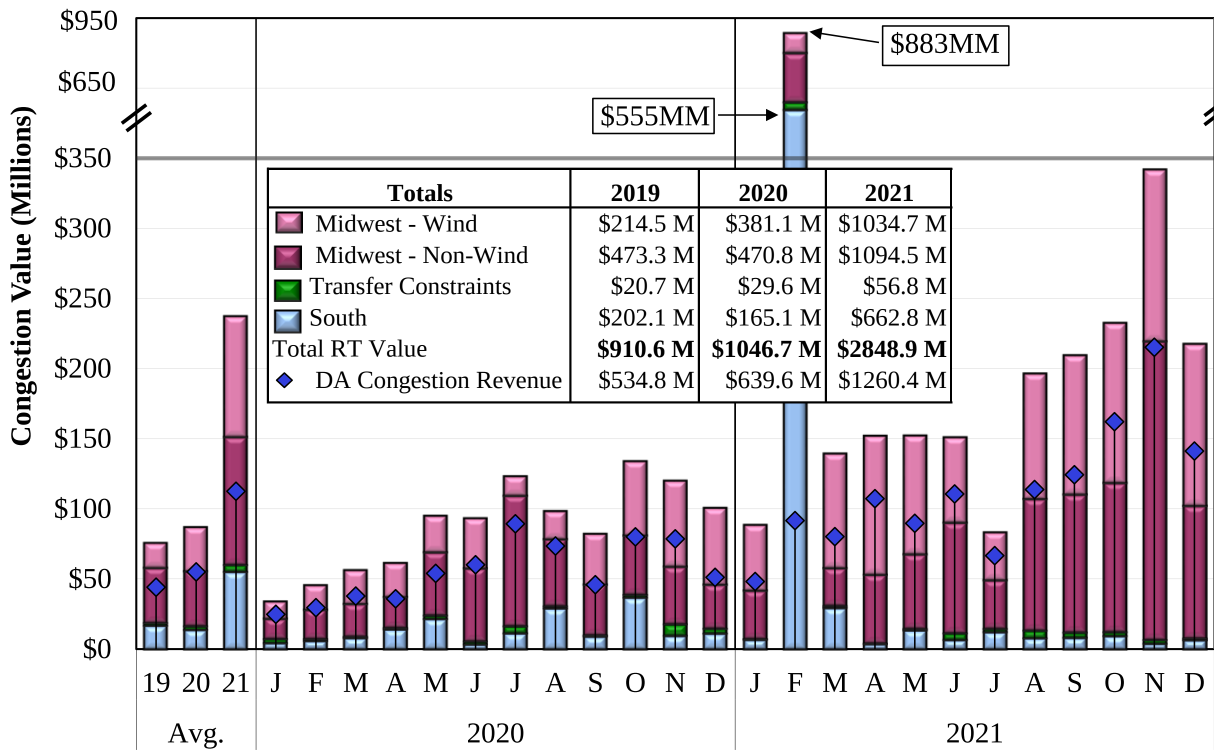
V. Transmission Congestion and FTR Markets

To avoid violating transmission constraints, MISO manages power flows over the network by adjusting resource dispatch levels. This process establishes efficient, locational prices that represent the marginal costs of serving load at each location. Transmission congestion arises when network constraints prevent MISO from dispatching the lowest-cost units. The resulting "out-of-merit" costs are reflected in the marginal congestion component (MCC) of the LMPs (one of three LMP components). The MCCs can vary widely across the system, raising LMPs in "congested" areas where generation relieves the constraints and lowering LMPs where generation loads the constraints. These price signals are valuable not only because they guide generation dispatch to efficiently manage network congestion, but also because they provide economic signals that facilitate efficient investment and maintenance of resources.

A. Real-Time Value of Congestion in 2021

We begin by summarizing the value of real-time congestion, 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 29 shows the monthly real-time congestion value over the past two years along with day-ahead congestion revenue.

Figure 29: Value of Real-Time Congestion
2020–2021



Totals	2019	2020	2021
Midwest - Wind	$214.5 M	$381.1 M	$1034.7 M
Midwest - Non-Wind	$473.3 M	$470.8 M	$1094.5 M
Transfer Constraints	$20.7 M	$29.6 M	$56.8 M
South	$202.1 M	$165.1 M	$662.8 M
Total RT Value	**$910.6 M**	**$1046.7 M**	**$2848.9 M**
DA Congestion Revenue	$534.8 M	$639.6 M	$1260.4 M

The value of real-time congestion rose significantly in 2021, nearly tripling to $2.8 billion. Roughly $730 million of this increase was related to severe congestion that occurred during Winter Storm Uri over just six days in February. Real-time congestion costs also increased in 2021 because of rising natural gas prices, particularly during the fall months, which increased the cost of re-dispatching natural gas generation to manage congestion.

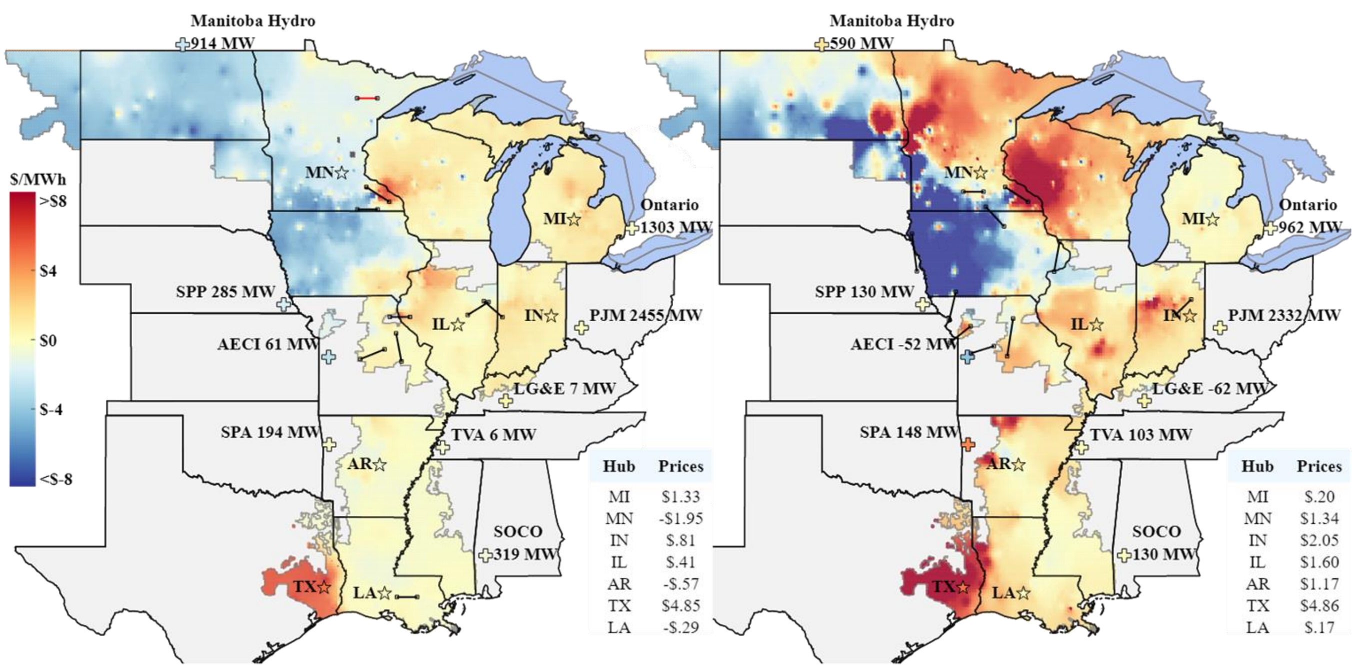
Finally, Figure 29 shows that transmission constraints loaded by wind resources accounted for an increasing level of real-time congestion—exceeding $1 billion in 2021—because of:

- Continued entry of new wind resources in MISO, SPP, and PJM that increase loadings on key constraints in MISO;
- The retirement of some key coal and gas-fired resources in recent years that had provided relief on these constraints; and
- Lower imports from Manitoba, where hydro output has been limited by drought conditions, that enter MISO at a location that lowers flows on the constraints exiting the wind locations in northwest MISO.

To illustrate the locational impacts of these changes, Figure 30is a map of the congestion in MISO in 2020 and 2021 showing the average marginal congestion components of each LMP. These MCCs show the average annual effect of congestion on the price at each location.

Figure 30: Average Real-Time Congestion Components in MISO's LMPs

2020 **2021**



These maps show that congestion has become more severe in the upper Midwest where most of the wind resources have entered the market in recent years. We expect these trends to continue as wind resources continue to enter the market. This will increase the importance of improving the utilization of MISO's transmission network in the area through improved transmission ratings, reconfiguration of the network, and strategic transmission investment.

In additional to these locational changes, we found that congestion became more difficult to manage in 2021. When flows on transmission facilities cannot be maintained below the facility limits, the transmission constraint demand curve will set the shadow price on these unmanageable constraints. Unmanageable congestion increased by $404 million in 2021.

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 flow power over particular elements of the transmission system.

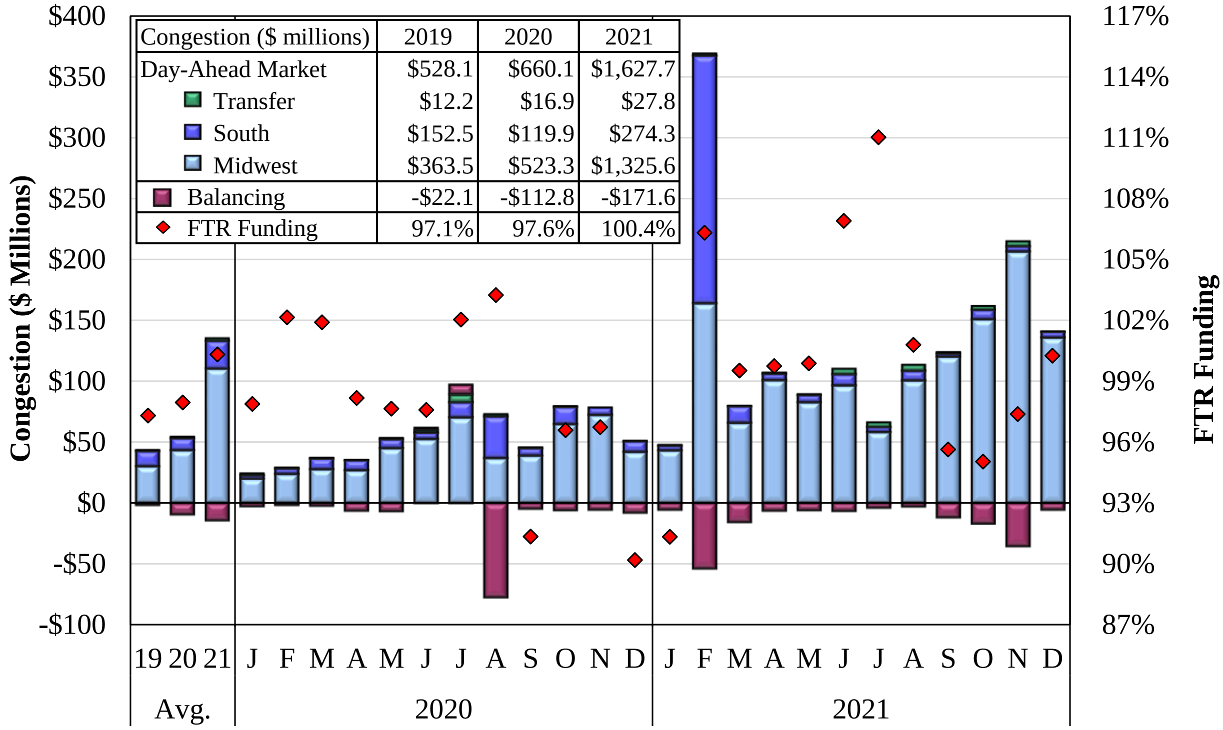
A large share of the value of these rights is allocated to participants based on historical firm use of the transmission network. Residual transmission capability not allocated to historical uses is sold in the FTR markets, with this revenue contributing to the recovery of the costs of the network. FTRs provide a means for market participants to hedge day-ahead congestion costs. If the FTRs issued by MISO are physically feasible, meaning that flows over the network sold as FTRs do not exceed flow limits 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 them 100 percent of the FTR entitlements).

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

- *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".

Figure 31 summarizes the day-ahead congestion by region (and between regions), balancing congestion incurred in real time, and the FTR funding levels from 2019 to 2021.

Figure 31: Day-Ahead and Balancing Congestion and FTR Funding
2019–2021



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.

Day-Ahead Congestion Costs

Day-ahead congestion costs nearly tripled to $1.6 billion in 2021. The day-ahead congestion costs collected through the MISO markets were about 56 percent of the value of real-time congestion on the system. This substantial difference is caused by loop flows that do not pay MISO for use of its network and by entitlements on the MISO system granted to SPP and PJM and other JOA parties that are not included in the day-ahead congestion settlement.

While day-ahead congestion costs increased in both the South and the Midwest, the overall increase was primarily driven by increases in the Midwest. Winter Storm Uri was the primary cause of the congestion increase in the South, while the factors described earlier in this section led to sustained congestion increases in the Midwest in 2021. FTRs were fully funded in 2021.

FTR Surpluses and Shortfalls

Overfunding and underfunding of FTRs is caused by discrepancies between the modeling of transmission constraints and outages in the FTR auctions and the day-ahead market. For example, if the limit on a day-ahead market constraint decreases below what cleared the FTR market, a congestion shortfall will occur. Conversely, a surplus will result when a limit on a day-ahead market constraint is higher than what cleared the FTR market. In 2021, day-ahead congestion revenues exceeded FTR obligations by nearly $17 million. These FTR surplus revenues are distributed back to transmission customers.

In the past, external constraints and low-voltage constraints have tended to be underfunded because a higher proportion of their FTR flows are below the GSF cutoff applied in the day-ahead and real-time markets. This cutoff causes MISO to not collect all the congestion revenue necessary to satisfy the FTR obligations. FTRs impacted by SPP constraints, for example, were funded at 94 percent of the total obligation in 2021. As we discuss later in this section, MISO has been responding to our recommendation to lower the GSF cutoff and these FTR funding issues have been diminishing. In contrast, FTRs over the transfer constraints between the South and Midwest regions tend to be overfunded because they can bind in both directions. This causes them to not be fully subscribed and to generate surpluses when binding in either direction.

One of the most significant causes for episodic underfunding continue to be planned and unplanned transmission outages—particularly forced and short-duration scheduled outages that are not reflected in the FTR auctions. In 2021, for example, a key transmission outage schedule was changed multiple times after the FTR auction cleared and contributed to over $64 million in FTR shortfalls. This can cause funding levels to vary substantially by local balancing area (LBA).[32] This potentially raises concerns regarding the incentive to fully report outages because FTR underfunding costs are socialized to all MISO areas. In contrast, reporting outages earlier or more completely could result in fewer FTRs being awarded to LSEs affiliated with the transmission owner.

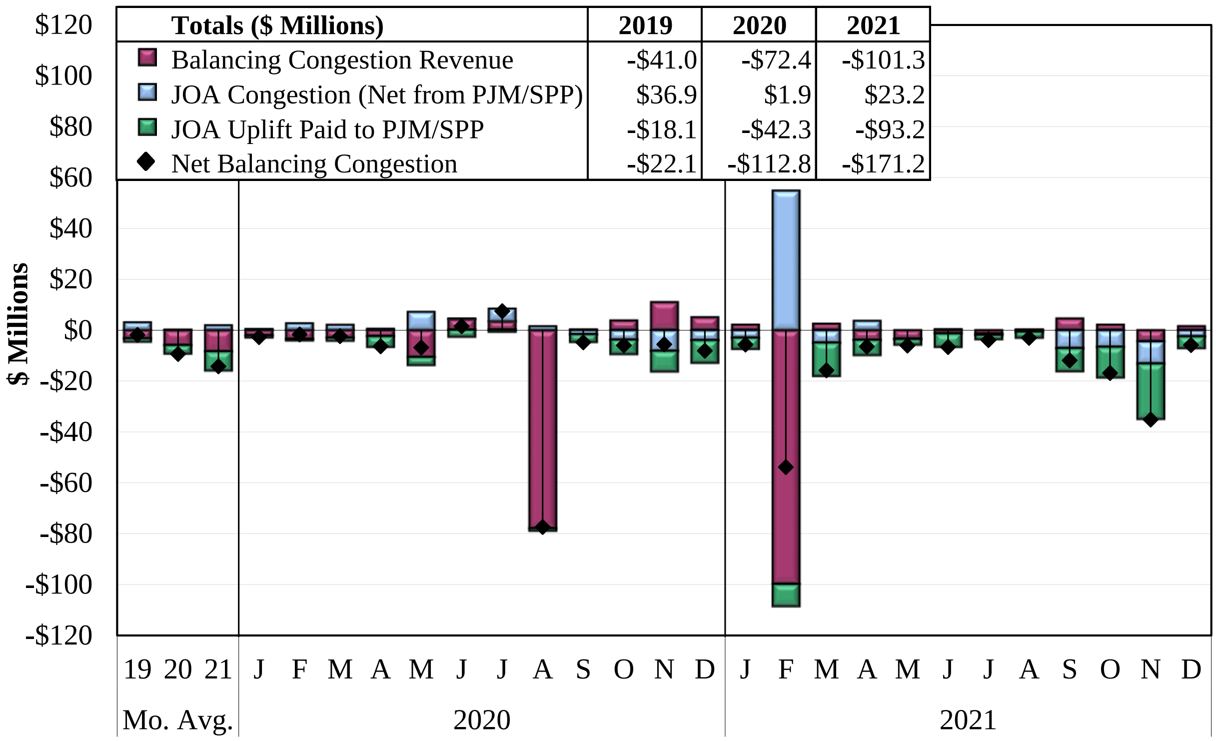
Balancing Congestion

Balancing congestion shortfalls (negative balancing congestion revenue) occur when the transmission capability available in real time is less than the capability scheduled in the day-ahead market. In other words, negative balancing congestion are the costs of re-dispatching generation to reduce real-time flows on a constraint from day-ahead scheduled flow levels. 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, derates, or loop flows that were not fully anticipated in the day-ahead market. Net negative balancing congestion must be uplifted to MISO's customers. These costs are collected from all real-time loads 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 the shortfalls by achieving maximum consistency between the day-ahead and real-time market models. Figure 32 shows the 2020 through 2021 monthly balancing congestion costs incurred by MISO.

[32] See *FTR Funding by Type of Constraint and Control Area* in Section V.B in the Analytic Appendix.

Figure 32: Balancing Congestion Revenues and Costs
2019–2021



Net balancing congestion increased by $58 million in 2021. The components of the total balancing congestion changed significantly, including balancing congestion revenue shortfalls changing by almost $30 million and JOA uplift more than doubling to $93 million. JOA uplift payments are made to pay for market flows that exceed entitlements on coordinated M2M constraints. The most significant balancing congestion event occurred in February during extreme cold and icing, and it led to unexpected generation and transmission outages and spikes in natural gas prices. This resulted in net balancing congestion costs exceeding $50 million.

C. FTR Market Performance

An FTR represents a forward purchase of day-ahead congestion. 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). It is important to recognize, however, that even if the FTR prices represent a reasonable expectation of congestion, a variety of factors may cause actual congestion to be much higher or lower than FTR auction values. MISO currently runs:

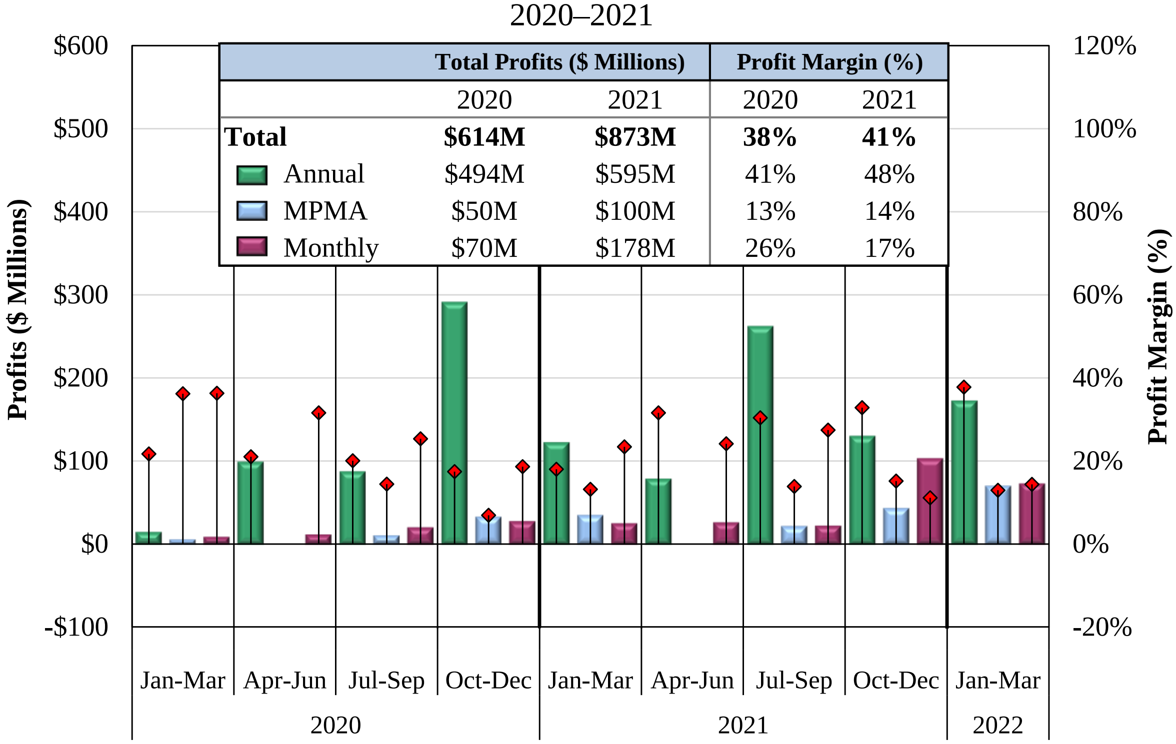
- An annual auction from June to May that includes seasonal and peak/off-peak resolution of bids, offers, and awards; and
- A Multi-Period Monthly Auction (MPMA) that yields monthly and seasonal peak/off-peak awards and facilitates FTR trading for future periods in the current planning year.

FTR Market Profitability

Figure 33 shows our evaluation of the profitability of FTRs in these auctions by showing the seasonal profits for FTRs sold in each market. For comparison purposes, profitability of monthly FTRs purchased in the MPMA are aggregated seasonally in this figure.

Annual FTR Profitability. Figure 33 shows that FTRs issued through the annual FTR auction were extremely profitable overall, rising to almost $600 million, up from roughly $500 million in 2020 and only $36 million in 2019. The rise in 2020 included the effects of hurricane-related events in the South in August and September. In 2021, Winter Storm Uri produced severe unanticipated congestion that made all FTRs unusually profitable. The increase later in the year because of higher natural gas prices and the other factors discussed above was also largely unanticipated and led to high FTR profits. In prior years, FTR losses were incurred when market participants nominated and self-scheduled ARRs along historically unprofitable paths. This practice has steadily declined over the past four years.

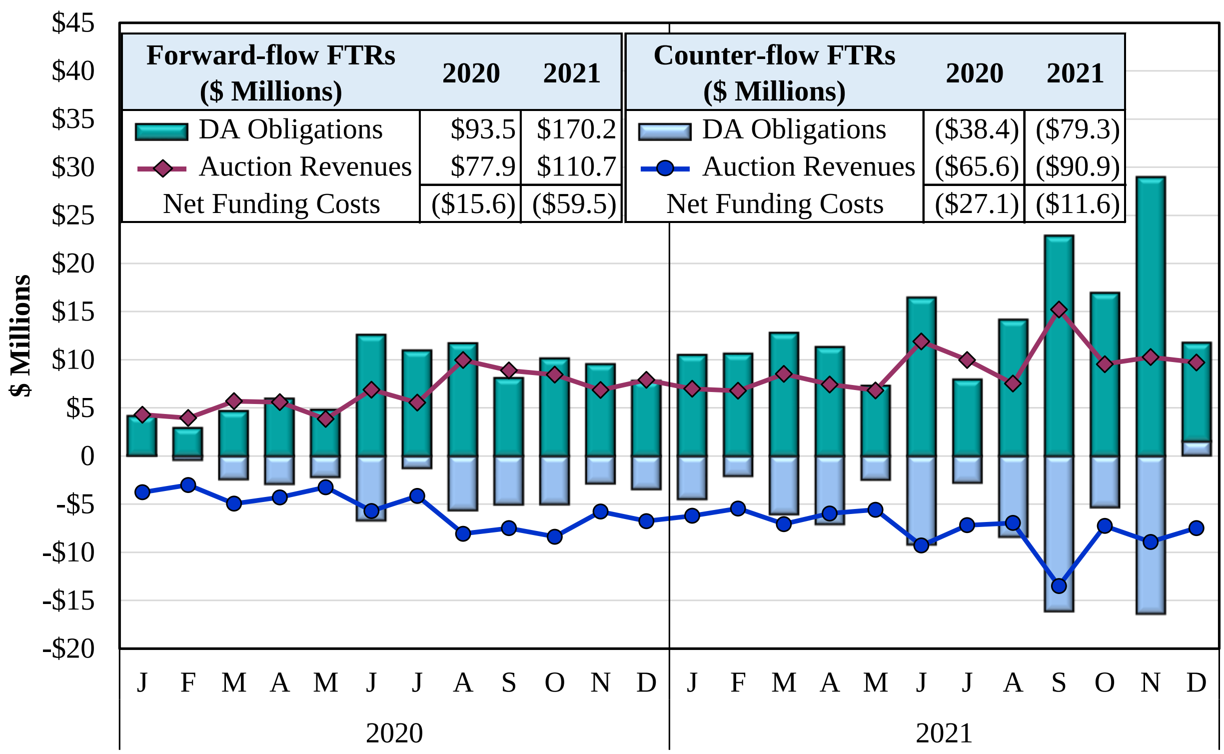
Figure 33: FTR Profits and Profitability
2020–2021



FTR Profitability in the MPMA. Figure 34 shows that the FTRs purchased in the MPMA and prompt month auction doubled over last year, from $50 million to $100 million. In general, the MPMA markets should produce prices that are more in line with anticipated congestion than the annual auction because they are cleared much closer to the operating timeframe when better information is available to forecast congestion. However, these results indicate that there is clearly room for improvement in the performance of the auction. This increase in FTR profits is the result of the sale of both forward-flow and counter-flow FTRs.

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure 34 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 34: Prompt-Month MPMA FTR Profitability
2020–2021



The analysis shows that the discount in the sale for forward-flow FTRs increased from 17 percent in 2020 to almost 35 percent in 2021, which translated into net funding costs (i.e., profits from these FTRs) of almost $60 million. These results indicate that the markets did not fully anticipate the magnitude of the rise in congestion that occurred in late 2021.

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.[33] Net funding deficits for counter-flow FTRs decreased significantly in 2021 because of the sharp increase in day-ahead congestion that occurred late in the year.

Overall, these results indicate that the MPMA lacks the liquidity necessary to erase the systematic differences between FTR prices and values. Ideally, barriers to participation should be identified and eliminated, which should lead to better convergence between the auction revenues and the associated day-ahead FTR obligations. If such improvements cannot be identified, it may be beneficial for MISO to examine its auction processes to determine whether to limit the sale of forward-flow FTRs at unreasonably low prices and/or the sale of counter-flow FTRs at unreasonably high prices.

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

MISO's market-to-market (M2M) process under the Joint Operating Agreement (JOA) 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. The RTO with the lower cost 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 increased in 2021:

- Congestion on MISO M2M constraints more than doubled to total $1.2 billion in 2021.
- Congestion on external M2M constraints (those monitored by PJM and SPP) rose 169 percent in 2021.

Table 9 shows MISO's annual M2M settlements with SPP and PJM over the past two years.

33 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.

Table 9: M2M Settlements with PJM and SPP ($ Millions)
2020–2021

	PJM	SPP	Total
2021	$18	-$88	-$70
2020	$45	-$80	-$35

This shows that net payments generally flowed from PJM to MISO because PJM exceeded its FFEs on MISO's system. The opposite has been true with SPP, partly because SPP enjoys relatively high FFEs on a number of key constraints in both SPP and MISO. We are currently reviewing these FFE calculations to identify any potential concerns. The increase that occurred with SPP was partly due to high wind along the SPP seams and generator retirements that reduced MISO's ability to relieve the wind-related constraints.

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 for 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 to be 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
2018–2021

Item Description	PJM ($ Millions)				SPP ($ Millions)				Total ($ Millions)			
	2018	2019	2020	2021	2018	2019	2020	2021	2018	2019	2020	2021*
Never classified as M2M	$5	$1	$4	$17	$15	$14	$34	$50	$21	$15	$38	$68
M2M Testing Delay	$22	$8	$2	$20	$8	$10	$18	$55	$29	$17	$20	$75
M2M Activation Delay	$11	$1	$3	$2	$7	$1	$2	$34	$18	$2	$5	$36
Total	$38	$10	$9	$39	$30	$25	$54	$139	$68	$34	$62	$178

*We have excluded the Winter Storm Uri days (02/13 - 02/19), that could have added another ~$84 MM in the 'Never classified as M2M' category

Historically, the highest congestion occurred on constraints that MISO failed to test, prompting a recommendation in the 2016 SOM for MISO to improve M2M identification and testing procedures. In December 2017, MISO implemented a tool to improve these procedures, which resulted in significant improvements in the process in 2018 and 2019. More recently, congestion associated with failure to test constraints or delays in testing constraints increased sharply in both 2020 and 2021. Most of the increase in 2021 was likely due to the effects of higher natural gas prices and the increasing volatility of congestion along the SPP seam. However, based on these results, we encourage MISO to evaluate ways to improve its M2M processes and timeliness of the testing process, particularly with SPP.

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 5 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.[34] The single generator test is particularly questionable because it ignores the size and economics of the unit—this test does not ensure that the NMRTO has any economic relief.

Our analysis of this area of the M2M process, presented in detail in Section V.E of the Analytic Appendix, shows that there are a number of M2M constraints for which the NMRTO has a very small portion of the economic relief and very little ability to assist in managing the congestion. If the NMRTO's market flows are also low on these constraints, then they should not be M2M constraints because the savings of coordinating 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—particularly 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 relief capability from the NMRTO; and/or
- The NMRTO relief as a percentage of the transmission limit.

Using threshold values for these tests of 10 percent would be reasonable because it correlates well with coordination benefits. We recommend that no relief be assumed from raise-help wind resources because they typically cannot increase their output in response to dispatch instructions. Our analysis shows that implementing this recommendation would likely reduce the total number of M2M constraints. In other words, the five percent test is identifying more constraints that are not beneficial to coordinate (i.e., false positives) than the number of new constraints that would warrant coordination under the relief-based tests.

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:

- Some of the costliest M2M constraints are more efficient for the NMRTO to monitor because it has most of the effective relief capability. MISO and SPP began using software in 2017 that enables the transfer, but it has rarely been used. PJM has postponed implementation of this software and currently only allows such transfers in limited circumstances. We recommend MISO continue working with SPP and PJM to improve the procedures to transfer the monitoring responsibility to the NMRTO when appropriate.
- Convergence of M2M constraints is much worse in the day-ahead market. MISO and PJM implemented our recommendation to coordinate and exchange FFE in the day-ahead market in late January 2016, but they do not actively utilize this process. Further, we

34 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.

have found that SPP does not appear to be modelling MISO's constraints in its day-ahead market. We recommend MISO work with SPP and PJM to improve the day-ahead modeling and convergence of the M2M constraints.

E. Congestion on Other External Constraints

In addition to congestion from internal and external M2M constraints, congestion in MISO can occur when MISO models the impact of its own dispatch on external constraints. MISO is obligated to activate these constraints and reduce its market flows when other system operators invoke Transmission Loading Relief procedures (TLR). 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 neighbors 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 particular, we found:

- $353 million of congestion on constraints TVA generation could economically relieve.
- $317 million of congestion on constraints AECI generation could economically relieve.
- Substantial costs and price effects associated with TLRs called by both TVA and IESO, which MISO would relieve more economically by coordinating the relief.

In early 2020, TLRs called by IESO became frequent. These TLRs, 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.

F. Transmission Ratings and Constraint Limits

For the past several years we have estimated significant potential benefits from improved utilization of the transmission system, in particular 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.[35] 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 which requires TOs to provide AARs and emergency ratings based on facility specific evaluations within three years.[36]

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, emergency ratings for MISO's transmission facilities.[37] 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
2020–2021

		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	**Emergency Ratings**	**Total**		
2020	**Midwest**	$57.2	$42.69	$99.9	22	10.8%
	South	$4.5	$8.80	$13.3	3	9.3%
	Total	**$61.8**	**$51.5**	**$113.3**	**25**	**10.6%**
2021	**Midwest**	$156.6	$100.17	$256.8	29	11.9%
	South	$26.9	$38.14	$65.1	1	9.9%
	Total	**$183.5**	**$138.3**	**$321.8**	**30**	**11.4%**

Across the past two years, the results show average benefits of roughly 11 percent of the real-time congestion value. The total potential savings in 2021 were nearly one third of a billion

35 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.

36 Docket RM20-16-000.

37 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 the data for other facilities for which TOs submit emergency ratings. We then estimate the value of these increases (both the temperature-based increases and the emergency rating increases) based on the shadow prices of the constraints.

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 2021 are distributed in the areas served by transmission owners.

Actual Savings Achieved by Two of MISO's TOs

In 2015, MISO began a pilot program to employ temperature-adjusted, short-term emergency ratings on several key facilities operated by Entergy. Over time, the program has expanded to include additional Entergy facilities and has yielded clear benefits without causing reliability issues. Only one other transmission owner currently utilizes temperature-adjusted ratings on a significant number of its transmission facilities. We have estimated the savings that are currently being achieved by these two transmission owners. At least one TO adjusts its ratings on an hourly basis to maximize the benefits, and the benefits are substantial, as shown in Table 12. These benefits are estimated by multiplying the rating increases (from the static rating) by the marginal value of the transmission as measured by the prevailing shadow prices.

Table 12: Estimated Achieved Savings by Two Transmission Owners
2020–2021

	Savings ($ Millions)	Share of Congestion	Facilities in Program
Midwest	$26.7	5.2%	48
South	$25.2	3.7%	122
Total	**$51.9**	**4.4%**	**170**

The table shows that actual savings totaled about $52 million over two years—more than 4 percent of the congestion cost on these facilities. This a conservative estimate given that the shadow price would be higher if the market were controlling to a lower, non-adjusted rating.

Recommended Improvements to Achieve the AAR Benefits

The benefits shown above assume that each of the constraints that were deemed to be adjustable with temperature were adjusted and that emergency ratings were used for each constraint. In reality, it takes some time to prepare MISO's systems to receive the dynamic adjustments in the ratings and for the TO to gather the information to calculate the adjustments.

As MISO plans for compliance with Order 881, we encourage it to accelerate efforts to implement AARs and Emergency Ratings in real time, and MISO should enable forecasted ratings in the day-ahead market as soon as practicable. This should include beginning to collect the data and information necessary to validate transmission ratings consistent with the requirements of Order 881 and the TO Agreement.

Together, these changes will substantially improve the utilization of MISO's transmission network and ultimately lower the costs to MISO's customers. As MISO increases its system flexibility, it will be able to capture a larger share of the total potential benefits from the use of ambient temperature-adjusted ratings. Section V.D of the Analytic Appendix estimates the increase in benefits associated with these improvements in system flexibility.

G. Other Key Congestion Management Issues

MISO generally experiences significant real-time congestion each year—rising in 2021 to a record $2.8 billion. Hence, improvements aimed at the efficiency of its congestion management can deliver sizable savings. Many of these improvements are discussed earlier in this section. We discuss three remaining improvements in this subsection.

Generation Shift Factor Cutoff

MISO employs a GSF cutoff to limit the number of resources and loads that are deemed to affect the flows over a constraint in its market models. This is intended to allow the models to solve more quickly, but it also reduces the efficiency of the solutions. Previously, we recommended that MISO lower the GSF cutoff in both the day-ahead and real-time markets to manage flows on market-to-market constraints. Beginning in October 2021, MISO began the process of gradually reducing the GSF cutoff in both markets and continues to closely monitor market performance and market outcomes. Barring significant market or operational issues, the cutoff ultimately will be reduced to 0.5 percent or lower. This will produce substantial savings at little or no cost.

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 35 summarizes the effects of uncoordinated planned outages on congestion by showing the portion of the real-time congestion value for 2020 and 2021 that occurred on internal constraints that were substantially affected (at least 10 percent of the constraints' flows) by two or more planned outages.

Figure 35: Congestion Affected by Multiple Planned Generation Outages
2020–2021

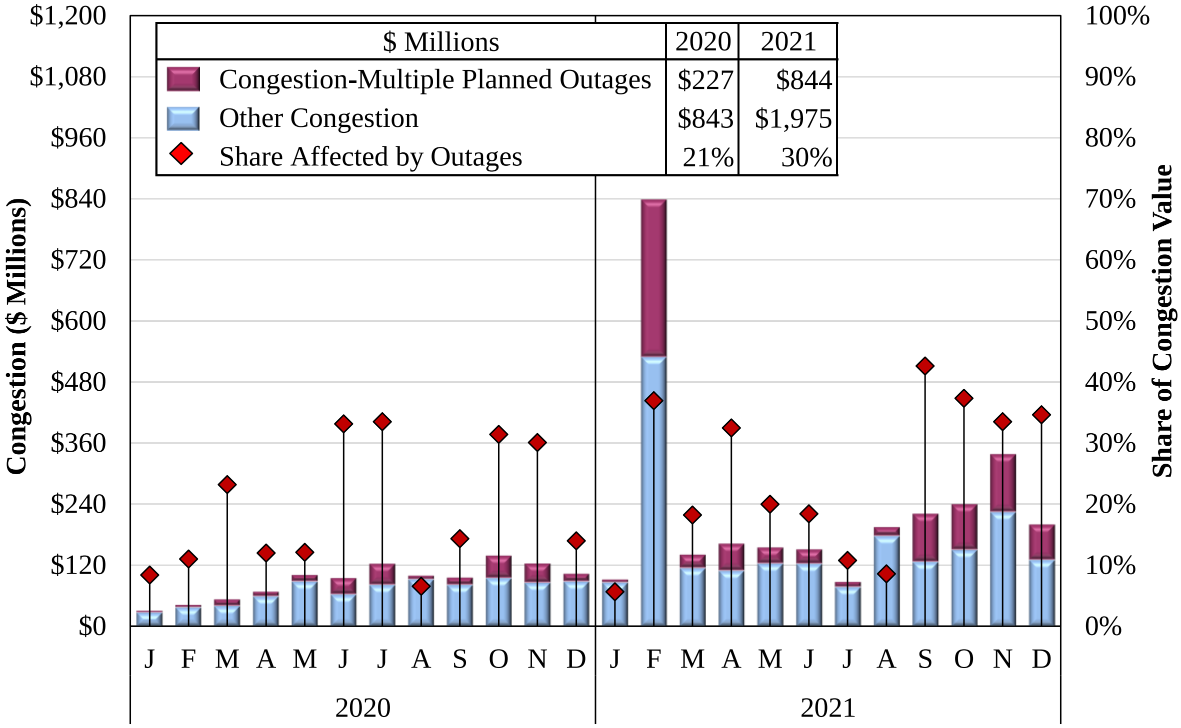


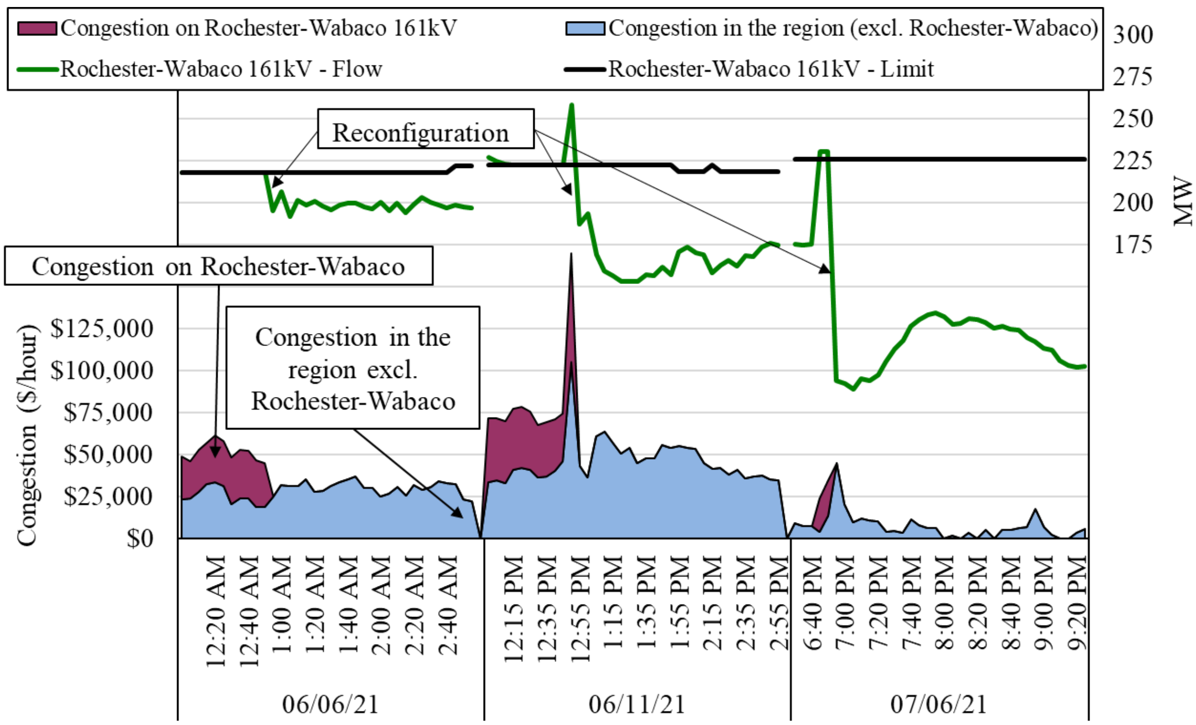
Figure 35 shows that 30 percent of the total real-time congestion on MISO's internal constraints in 2021 ($844 million) was attributable to multiple planned generation outages. In several months, planned outages caused significant congestion, including almost a third of all congestion in a number of months. The large increase in outage-related congestion costs in 2021 was associated with the severe congestion costs during Winter Storm Uri in February and the high congestion costs late in the year. Figure 35 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 in order to reduce unnecessary economic costs.

Identification and Use of Economic Transmission Reconfigurations

Today, transmission flows and congestion are primarily controlled by altering the output of resources in different locations. They can also sometimes be altered by reconfiguring the network (e.g., opening a breaker). 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.

To illustrate these benefits, consider the costliest constraint during the summer, the Rochester-Wabaco 161 KV line, which generated over $57 million in congestion. This constraint primarily limits the output of wind resources in the North and has a defined reconfiguration that is used when deemed warranted to address reliability concerns. We analyze the use of the reconfiguration in June and July in Figure 36. The figure shows the congestion occurring on the Rochester-Wabaco facility in the bottom panel, as well as on nearby facilities impacted by the reconfiguration option. The flows on the Rochester-Wabaco facility are shown in the top panel.

Figure 36: Impacts of Reconfiguration on the Rochester-Wabaco Line
June and July 2021



This analysis shows that when the reconfiguration is implemented, congestion on the Rochester-Wabaco line is eliminated as the flows drop well below its limit. Approximately one third of the congestion reduction moves in the immediate term to nearby facilities. Hence, the reconfiguration immediately reduces the overall congestion that had occurred on Rochester-Wabaco by two thirds. However, after the immediate shift in congestion caused by the reconfiguration, the congestion on other nearby facilities tends to dissipate as generation moves to more efficiently manage the congestion on the other facilities. Hence, benefits of this reconfiguration in mitigating the severe congestion on this facility are larger over time.

We believe this case study is representative of the opportunities to develop economic reconfiguration options on other frequently binding constraints and deploying them a regular congestion management action. Hence, we recommend 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.

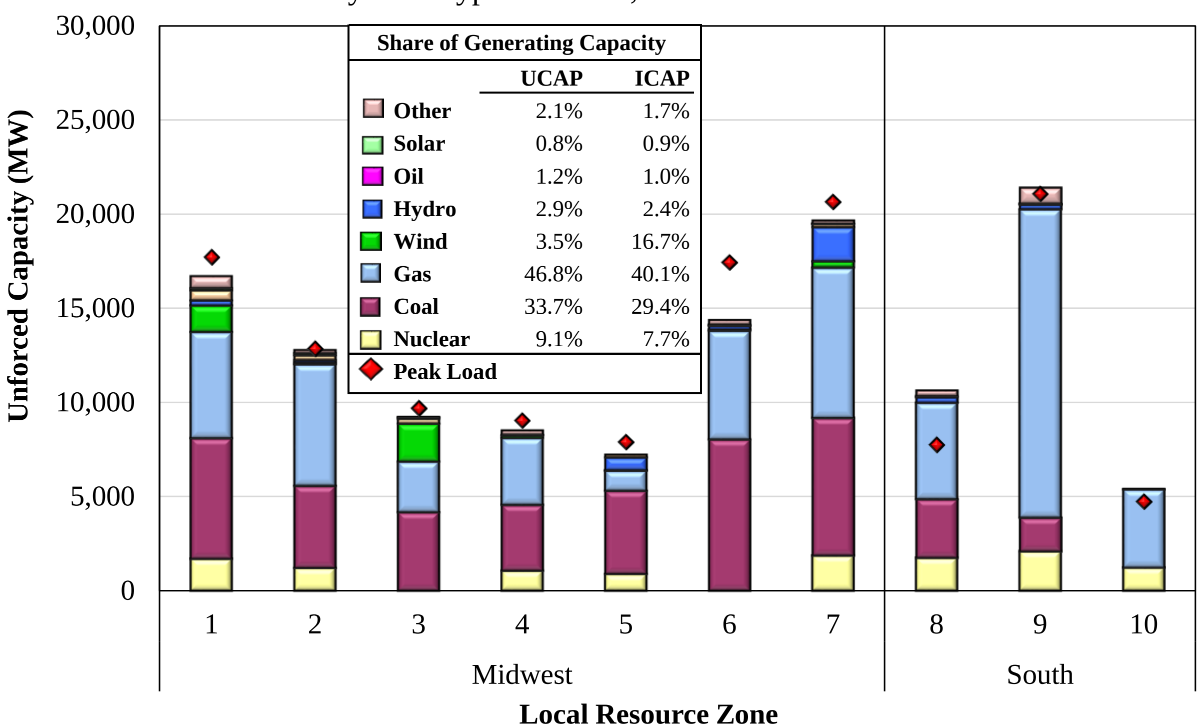
VI. Resource Adequacy

This section evaluates the performance of the markets in facilitating the investment and retirement decisions necessary to maintain resources to meet system reliability. 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 37 shows the distribution of Unforced Capacity (UCAP) at the end of 2021 by Local Resource Zone (LRZ) and fuel type, along with the coincident peak load in each zone.[38] 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. Hence, although wind is over 15 percent of MISO's ICAP, it is three percent of the UCAP.

Figure 37: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2021



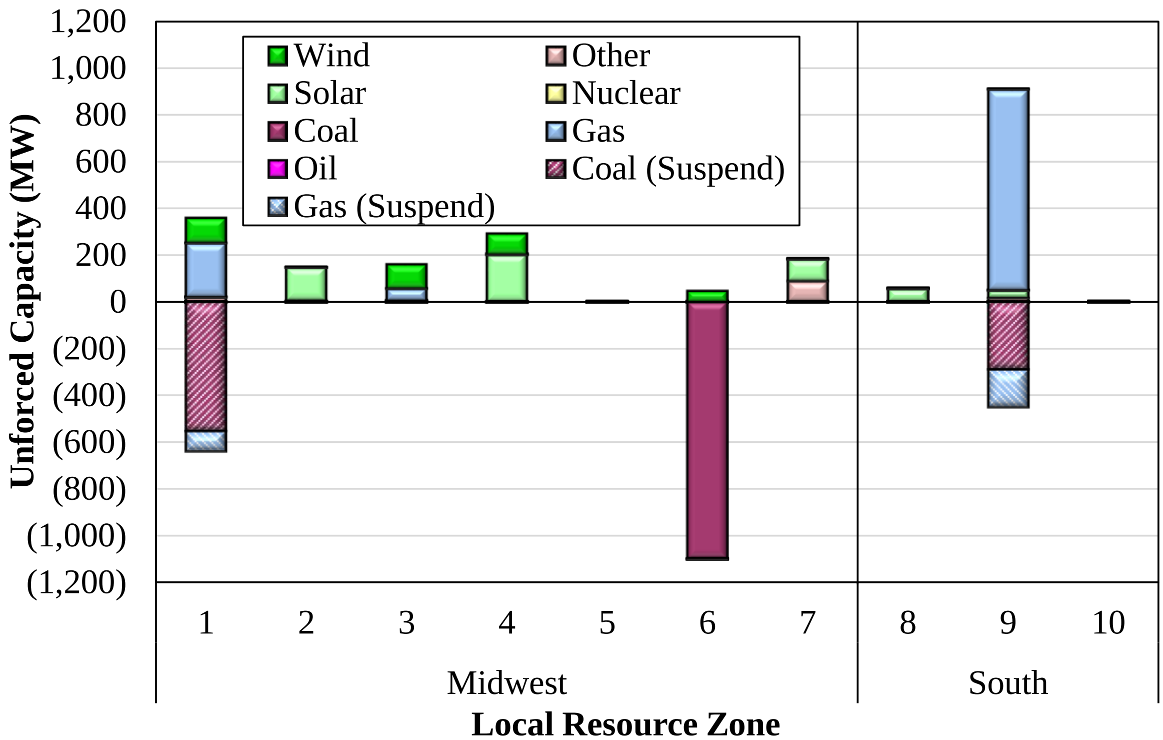
This figure shows that gas-fired resources account for a larger share of MISO's capacity than any other capacity type, including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from the MISO South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

38 UCAP was based on data from the MISO PRA for the 2021-2022 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 intermittent renewable resources. Figure 38 shows the capacity additions (positive values) and losses during 2021. 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 being used. Figure 38 does not show retirements for resources in 2021 that were suspended in 2020.

Figure 38: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone in 2021



Capacity Losses

In 2021, 2.2 GW of resources retired or suspended operations in MISO, primarily of coal and gas steam turbines. Approximately 300 MW of the suspended unforced capacity is under consideration for partial replacement and could return as new generation (primarily solar) in the next three years.[39] We expect baseload retirements to continue in the near term because of the weak economic signals provided by MISO's current capacity market.

39 See MISO Generator Replacement Requests: https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

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

New Additions

In 2021, 2.2 GW of unforced new capacity entered MISO. A 1 GW natural gas-fired combined-cycle resource entered in MISO South in a key constrained area. Nearly 2 GW (nameplate) of wind entered, although their total UCAP value is only 330 MW because they provide less reliability than conventional resources. Additional investment in wind resources is likely to occur given continued Federal subsidies. Nearly 1 GW (nameplate) of solar resources also entered in 2021.

C. Planning Reserve Margins and Summer 2022 Readiness

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted summer peak loads in 2022. Assumptions regarding the supply that will be available during the summer peak and the peak load can substantially change the planning reserve margins. Therefore, Table 13 presents a base case scenario and four additional scenarios that more realistically represent the range in MISO's summer peak reliability margin.

Base Scenario. We have worked closely with MISO to align our Base Scenario with MISO's assumptions in its *2022 Summer Resource Assessment*, including the 1,900 MW transfer limit assumption between MISO South and Midwest.[40] 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, 2022. The planning reserve margin shown is 17.9 percent – which is the Planning Reserve Margin Requirement (PRMR). We replaced the UCAP-based PRM added to demand response resources to an ICAP-based PRM to be consistent with reporting the Summer Assessment on an ICAP basis, and for wind we used the wind ELCC value and applied an ICAP-based PRM to assume a wind ICAP value. 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;

40 We do not think this is a reasonable assumption based on real-time operations, but we include this assumption to align our Base Case with MISO's Base Case.

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

Table 13: Summer 2022 Planning Reserve Margins

		Alternative IMM Scenarios*			
				High Temperature	
	Base Scenario	Realistic Scenario	Realistic <=2HR	Realistic Scenario	Realistic <=2HR
Load					
Base Case	124,505	124,505	124,505	124,505	124,505
High Load Increase	-	-	-	6,974	6,974
Total Load (MW)	124,505	124,505	124,505	131,479	131,479
Generation					
Internal Generation Excluding Exports	131,726	131,726	131,726	131,726	131,726
BTM Generation	4,473	4,473	3,276	4,473	3,276
Unforced Outages and Derates**	-	(9,319)	(9,319)	(16,919)	(16,919)
Adjustment due to Transfer Limit	(1,329)	-	-	-	-
Total Generation (MW)	134,870	126,880	125,683	119,280	118,083
Imports and Demand Response* **					
Demand Response (ICAP)	8,181	6,136	3,042	6,136	3,042
Firm Capacity Imports	3,700	3,700	3,700	3,700	3,700
Margin (MW)	22,246	12,210	7,920	(2,364)	(6,654)
Margin (%)	**17.9%**	**9.8%**	**6.4%**	**-1.8%**	**-5.1%**
Expected Capacity Uses and Additions					
Expected Forced Outages****	(6,810)	(6,515)	(6,515)	(6,515)	(6,515)
Non-Firm Net Imports in Emergencies	4,293	4,293	4,293	4,293	4,293
Expected Margin (MW)	19,729	9,989	5,698	(4,585)	(8,876)
Expected Margin (%)	**15.8%**	**8.0%**	**4.6%**	**-3.5%**	**-6.8%**

* Assumes 75% response from DR.
** Base scenario shows approved planned outages for summer 2022. Realistic cases use historical average unforced outages/derates during peak summer hours. High temp. cases are based upon MISO's 2022 Summer Assessment.
*** Cleared amounts for the 2022/2023 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.

In this Realistic Scenario, the planning reserve margin falls to 9.8 percent. This planning reserve margin would raise concerns for many RTOs, but 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 to 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.[41] This is conservative because the import levels would likely rise to much higher levels in response to shortage pricing in MISO. The table also shows the capacity that would be lost based on a historical average forced outage rate of around 5 percent. When offset by the non-firm imports, the realistic margin falls to 8.0 percent.

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 result from unforeseen events, MISO has historically declared emergencies between 10 minutes and 4 hours in advance. Because a large quantity of emergency resources offer 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 4.6 percent after accounting for expected forced outages and non-firm summer imports.

High Temperature Scenarios. We include two other variants of scenarios 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 temperature or other environmental restrictions cause certain resources to be derated.[42] 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 -1.8 to -5.1 percent). MISO will likely be well into emergency conditions in these cases because it must have a positive margin of 2,400 MW to satisfy its operating reserve requirements. We note, however, that the roughly 8 GW of firm and non-firm imports shown in the table is far less than the total import capability. Therefore, MISO would not likely need to shed load in most of these cases provided that its markets are effective in motivating high levels of imports.

Overall, these results indicate that the system's resources are likely adequate for summer 2022 but may run short if the peak demand conditions are much hotter than normal. The main implication of the summer reserve margin falling below the requirement is an increased probability that MISO will experience emergencies and potentially shed load. Going forward, planning reserve margins will likely continue to decrease as fossil and nuclear resources retire and are replaced by renewable resources. Therefore, it remains important for the capacity market and shortage pricing to provide the efficient economic signals to maintain adequate resources.

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41 The additional imports are consistent with the non-firm external support assumptions in MISO's sub-annual construct proposal. See Nov. 2020 RASC Item 4a, *Reliability Rqmts and Sub-Annual Construct*.

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

D. Capacity Market Results

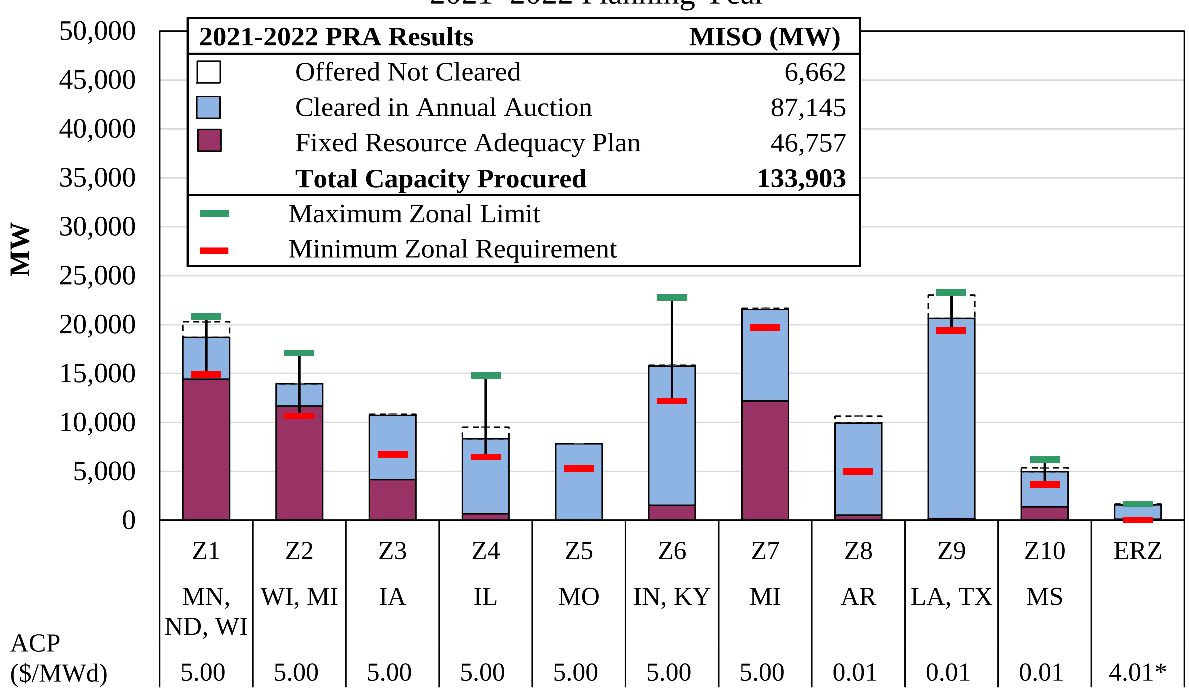
The purpose of capacity markets is to facilitate long-term resource decisions to satisfy RTOs' planning requirements in conjunction with their energy and ancillary services markets. The economic signals provided by these markets together inform long-term decisions to build new resources, make capital investments in or retire existing resources, and import or export capacity.

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 2021–2022 Planning Year

Figure 39 shows the outcome of the PRA held in late March 2021 for the 2021–2022 Planning Year. The figure shows the minimum and maximum amount of capacity that can be purchased in the red and green lines. The stacked bars show the total amount of capacity offered. The stacked bars include capacity offered but not cleared (ghost bars), capacity cleared (blue bars), or self-supplied (maroon) in each zone. Zonal obligations are set by the greater of the system-wide planning reserve requirement or the local clearing requirement. The minimum amount is the local clearing requirement, equal to the local reliability requirement minus the maximum level of capacity imports. The maximum is equal to the obligation plus the limit on capacity exports.

Figure 39: Planning Resource Auctions
2021–2022 Planning Year



*Weighted Average Clearing Price

Prices. Zones 1 through 7 cleared at $5.00 per MW-day and 8 through 10 cleared at $0.01 per MW-day. The prices were extremely low and provide suppliers with less than three percent of the revenues needed to cover the cost of new entry for a new peaking resource. We discuss the underlying causes of these low prices in Section III.B, discussing capacity market design.

Discussion of Other Issues Affecting the Performance of the PRA

Transfer Constraint. As part of the Settlement Agreement with SPP, MISO may dispatch up to 2,500 MW of energy transfers from MISO South to MISO Midwest. However, MISO limits the transfer capability in the South to North direction to 1,900 MW in the PRA. This constraint bound in the 2021-2022 PRA and caused a small amount of price separation between MISO South and MISO Midwest. However, it bound again in the 2022–2023 PRA and contributed to the capacity shortage in the Midwest. Increasing the limit to an expected transfer capability closer to 2,500 MW would allow MISO to utilize its planning reserves more fully in MISO South. We recommend that MISO revise its transfer limit in future PRAs.

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 a new generating unit would have earned in MISO's markets in 2021.

Net revenue is 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 40 and Figure 41 show estimated net revenues for a new combustion turbine (CT) and combined-cycle (CC) generator for the last three years in the Midwest and South regions. For comparison, the figures also show the annual net revenue that would be needed for these investments to be profitable (i.e., the Cost of New Entry or "CONE"). We include in our analysis ghost bars that indicate the alternative net revenues that these resources would have received were MISO to have employed a sloped demand curve in its capacity market (as we discuss in Section III.B).

Net revenues rose in all regions in 2021, partly because higher natural gas prices contributed to higher energy and ancillary services prices throughout MISO, and partly because MISO experienced a period of sustained high prices during Winter Storm Uri in February 2021. However, even with the significant transitory effects of this arctic event, the net revenues in all regions were well short of the levels needed to motivate investment in new resources. This is notable given the capacity shortage that has emerged in the Midwest region. However, the ghost bars show that the MISO markets would generally have provided sufficient revenue to support investment throughout the Midwest and in Texas if it priced capacity efficiently.

Figure 40: Net Revenue Analysis
Midwest Region, 2019–2021

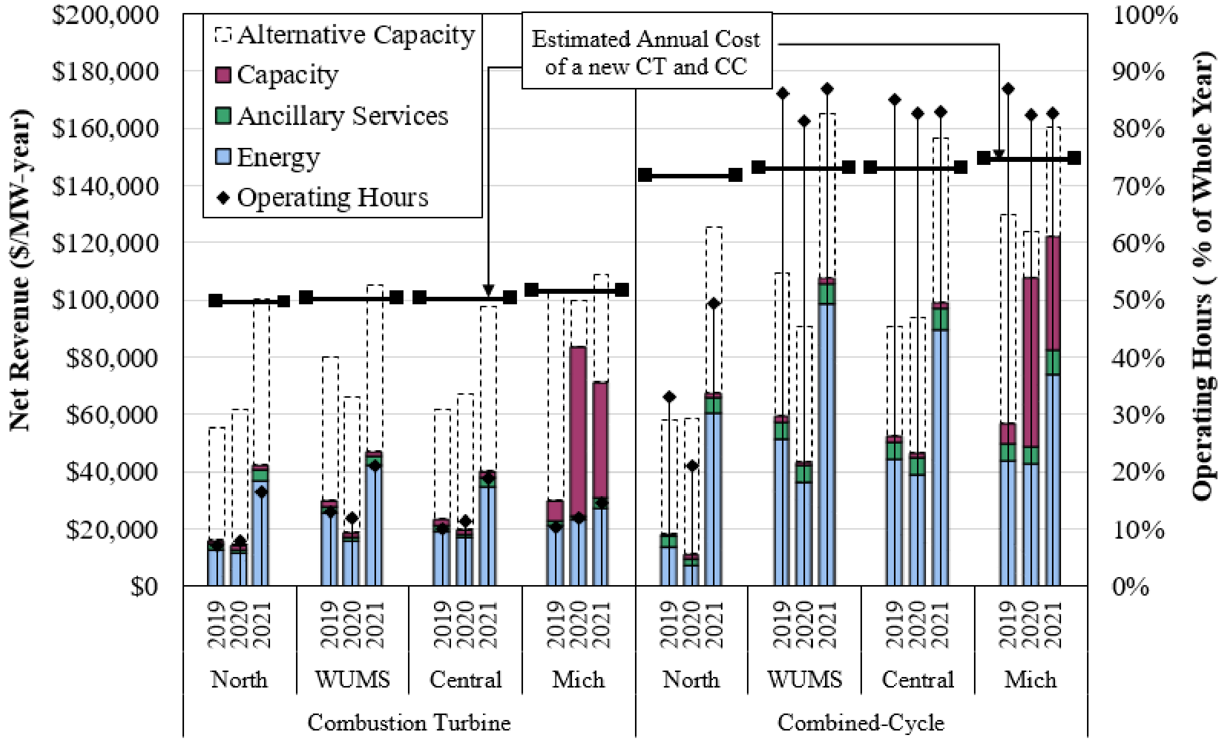
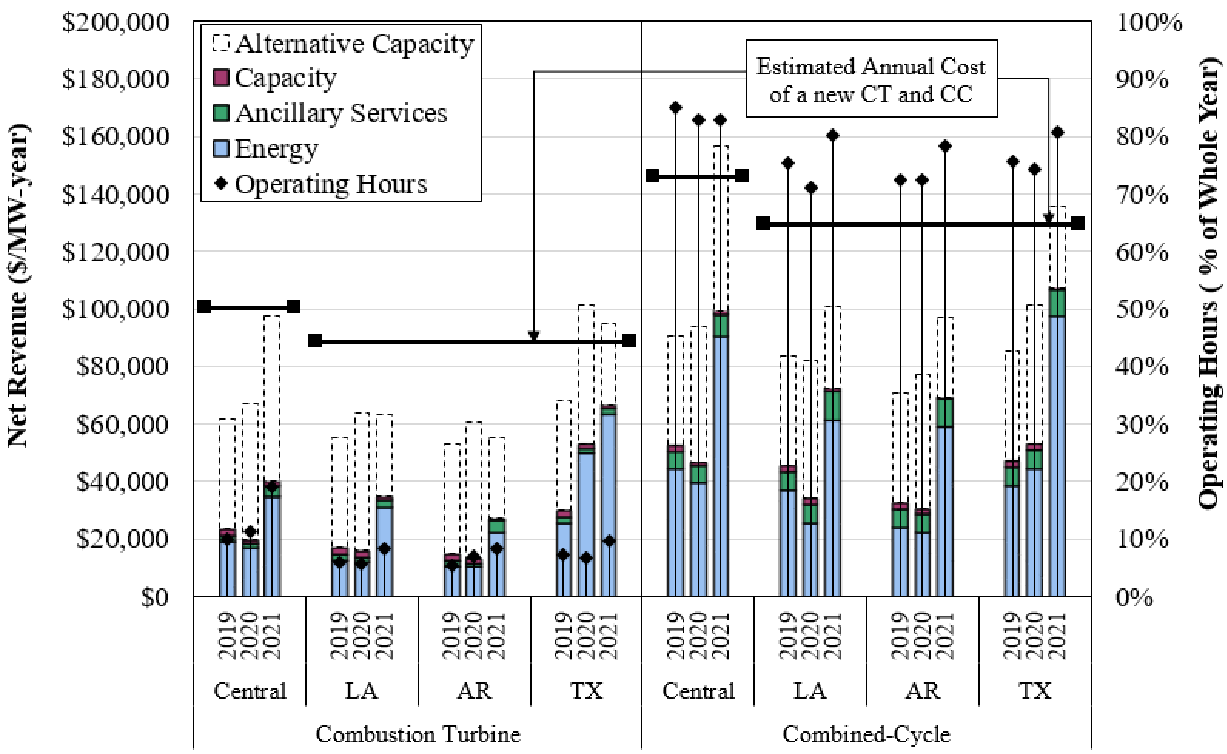


Figure 41: Net Revenue Analysis
South Region, 2019–2021



Note: "Central" refers to the Central region of MISO Midwest and is included for reference purposes.

These figures also show significant variations by zone. In Michigan, combined-cycle net revenues approached CONE because the 2020/2021 PRA cleared at CONE there.[43] Net revenues for combined-cycle resources in Texas approached CONE largely because of the sustained shortage conditions and associated high prices during the Winter Storm Uri arctic event. CT net revenues were lower than CC net revenues across the board because CTs have higher marginal costs that cause them to run in fewer hours with smaller margins.

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). Had MISO employed a reliability-based demand curve in the Planning Resource Auctions, the annual net revenues would have been significantly higher in recent years and sustained economic merchant resources that have been retiring prematurely. This raises particularly timely concerns as MISO's capacity surplus is dissipating and resources face substantial economic pressure. This trend produced a capacity shortage in the Midwest Region in the 2022/2023 PRA that will reduce MISO's overall reliability. This issue is discussed in more detail along with our recommendation to address it in Section III.

F. Existing Capacity at Risk Analysis

Since its inception, MISO has enjoyed a surplus of capacity beyond the minimum reliability requirement. MISO's capacity surplus has dwindled in recent years as older baseload units have entered long-term suspension or retired. This trend has largely been due to falling natural gas prices and the poor design of MISO's capacity market that results in understated capacity prices.

Well-designed markets should provide sufficient net revenues to cover the costs of remaining in operation (i.e., Going-Forward Costs or "GFCs") for resources that provide material reliability. When resources cannot recover their GFCs, they are at risk of suspending or retiring prematurely. Moreover, some resources may reduce maintenance expenditures, leading them to have more frequent forced outages and deratings.

We conducted an analysis to evaluate MISO's capacity at risk for long-term suspension or retirement for three types of technologies in MISO: coal, nuclear, and wind. Our analysis shown in Figure 42 compares the annual resource net revenues to the GFCs. The net revenues and GFCs are based on technology-specific heat rates, variable costs, capacity factors and Technology-Specific Avoidable Costs (TSACs). A detailed description of our analysis can be found in the Appendix Section VI.F.

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43 The hypothetical unit in Michigan received the 2020-21 PRA clearing price at CONE for January-May ($257/MW-day) and the 2021-22 PRA clearing price of $5/MW-day for the rest of the year. Because the CONE was only earned part of the year, the 2021 net revenue did not fully reach CONE.

Figure 42: Capacity at Risk by Technology Type
2021

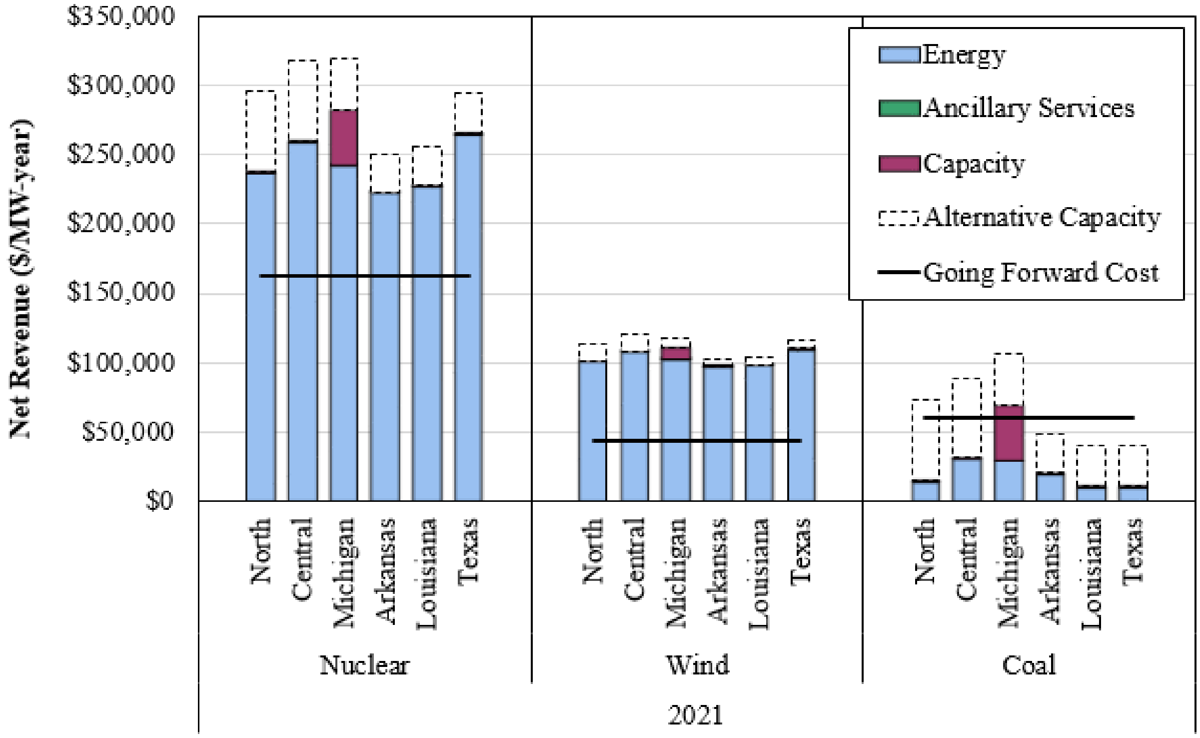


Figure 42 shows that while nuclear and wind resources are more than revenue adequate, even without including tax credits, typical coal resources exhibit revenue shortfalls under the current capacity construct. Even with higher gas prices in 2021, many coal resources rely on additional compensation through MISO's capacity auction to cover their going-forward costs. Many coal-fired resources in MISO are owned by vertically-integrated utilities that have guaranteed returns on investment that are approved through rate cases. Barring out-of-market cost recovery, most of these resources would be uneconomic to continue operating at the prices that prevailed in 2021.

Figure 42 also shows that were MISO to price capacity efficiently (by adopting a reliability-based demand curve), typical coal resources would be able to recover their GFCs in the Midwest and avoid premature retirements. Overall, this analysis underscores how MISO's poorly specified demand in the PRA distorts its market signals and will continue to lead to inefficient investment and retirement decisions. A more detailed analysis of the range of net revenues for existing individual coal resources by zone over the past two years is shown in Section VI.F of the Analytic Appendix.

G. Capacity Market Reforms

MISO made a filing in November 2021 to propose changes in two primary resource adequacy areas that are intended to allow MISO's capacity market to more effectively and efficiently satisfy its resource adequacy requirements.[44] These changes generally address two recommendations that we have made in recent *State of the Market* reports:

- Recommendation 2014-5: Transition to a seasonal capacity market; and
- Recommendation 2018-5: Improve the accreditation of capacity resources by recognizing resources' actual availability during tight conditions when reliability is most threatened.

We participated in the stakeholder processes to develop these proposed changes and provided extensive feedback and analyses to MISO in this process. We support the changes proposed by MISO because we believe they are improvements over MISO's current market design and rules. However, we raised some issues with the filing concerning elements that we believe reduce the benefits of these two broad changes.[45]

The seasonal capacity market proposal provides several benefits, including better serving non-summer reliability needs, improving outage coordination, and providing more flexibility on retirement/suspension decisions. The MISO filing proposes four seasonal auctions cleared simultaneously at the beginning of the planning year. Hence, this auction will occur immediately in advance of the summer season, but more than 6 months ahead of the winter season. We had recommended that MISO use prompt seasonal auctions so that participants could make auction decisions with less uncertainty.

Although MISO's accreditation proposal does not fully address our recommendation, we supported it because it will provide substantial benefits over the current construct. MISO's historic accreditation methodology has not aligned with the reliability value provided by different resources because: a) it has not accounted for unreported outages and derates or any type of outage other than a forced outage or derate reported in GADS; and b) it has not recognized that inflexible resources with long lead times are less valuable than more flexible resources. To address this issue, we had recommended that MISO reform its accreditation rules to base each resource's accreditation on its availability during the tightest market conditions.

MISO's accreditation proposal largely addresses this recommendation, but generally over-values inflexible resources. For example, it treats offline resources with up to a 24-hour lead time as available up to their offered output. Long-lead time units that seldom run are much less available than other resources in reality because MISO often does not recognize emergency

44 Docket No. ER22-495-000.

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

conditions until 30 minutes to 4 hours ahead of real-time. Offline long-lead time resources would predictably be unavailable for most of these emergencies, so accrediting them comparably to online resources or fast-starting gas turbines is not consistent with their reliability contributions. Nonetheless, the proposal is a significant improvement over the current unforced capacity accreditation, and we will monitor it closely to evaluate its performance going forward.

Other Recommended Improvements to the PRA

Although a reliability-based demand curve that we describe in Section III.B is the most important design improvement, followed by improving the accreditation of capacity resources, 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.

Accreditation of Emergency Resources. Emergency-only resources, including LMRs and emergency-only 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 2 hours warning. Therefore, we recommend that MISO develop a reasonable methodology for accrediting emergency-only resources in the PRA.

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.

Disqualifying Energy Efficiency (EE) from Selling Capacity. As discussed in more detail in Section IX.C, EE measures do not provide a dispatchable product or provide any other operating flexibility to assist MISO in maintaining reliability during emergency events. Additionally, the quantification of the EE is based on speculative assumptions and the resulting capacity payments to EE represents an inefficient subsidy. In many cases, entities are paid for activities independently being taken by others and in no way influenced or facilitated by the entity selling the EE to MISO. In these cases, procuring the "EE Resources" results in no savings. Therefore, we recommend MISO disqualify EE measures from satisfying capacity requirements or participating in the PRA.

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 14 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 2021:

- Day-ahead and real-time hourly net scheduled interchange (NSI) averaged 3.9 and 4.6 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 2021.
  - Hourly real-time imports from PJM averaged 2.8 GW, down 23 percent from 2020.
  - 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. In 2021, more than 60 percent of the transactions with PJM and nearly 65 percent of the transactions with SPP were scheduled in the profitable direction. Even though transactions are scheduled in the efficient direction more than half of the time, large untapped savings are available because it is often economic to schedule significantly more or less interchange. Many hours still exhibit large price differences that offer substantial production cost savings.

B. Coordinated Transaction Scheduling

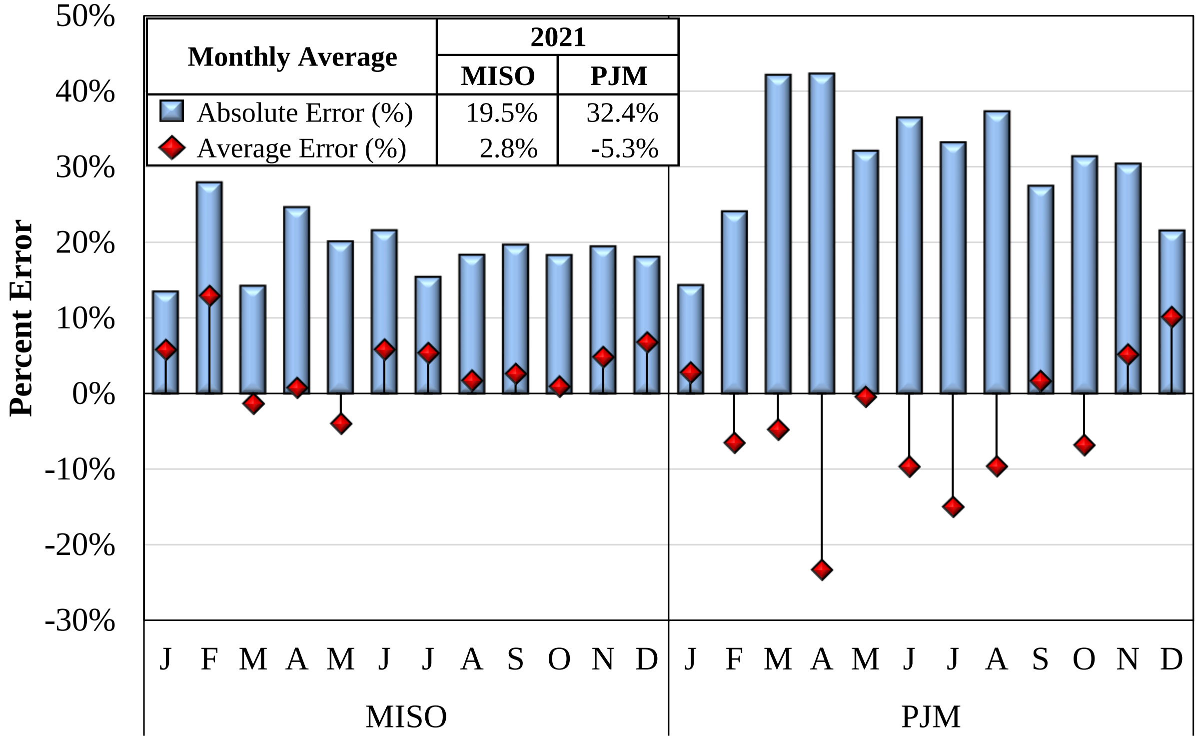
On October 3, 2017, MISO and PJM implemented Coordinated Transaction Scheduling (CTS). CTS allows market participants to submit offers to schedule imports or exports between the RTOs within the hour. Offers clear if the forecasted spread between the RTOs' real-time interface prices 30 minutes prior to the interval is greater than the offer price. CTS transactions are settled based on real-time interface prices.

Up until early 2019, there had been almost no participation in CTS. In 2021, the hourly average quantity of CTS transactions offered and cleared was 175 MW and 74 MW, respectively, up slightly from 140 MW and 60 MW in 2020. Over 99 percent of these transactions in 2020 and

2021 were in the import direction. CTS transactions remain a small 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 43, we show the forecasting errors by month in both average and absolute average terms for both MISO (left-hand chart) and PJM (right-hand chart).

Figure 43: MISO and PJM CTS Forecast Errors
2021



This analysis shows significant inaccuracies in the forecast prices used for CTS, particularly in PJM. In 2021, the average difference between PJM's real-time LMPs and its forecast prices for the interface was -5.3 percent, and the average of the absolute difference was 32.4 percent.[46] For the same period, the average difference between MISO's real-time LMPs and its forecast prices for the interface was 2.8 percent, and the average of the absolute difference was 19.5 percent. When combined, these errors severely hinder the effectiveness of CTS in improving pricing at the interface. In fact, the poor forecasts suggest that CTS is likely clearing many transactions that are uneconomic based on real-time spreads, as well as not clearing many transactions that would otherwise be economic.

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

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 consider 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 2021 of a CTS product 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 scheduled 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 change between five-minute intervals of 250 MW (in either direction), and (2) maximum total CTS import and export limits of 2,000 MW. Table 14 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 $23 million in production cost savings versus only $7 million under the current process. These savings do not require large adjustments in most intervals—which average roughly 80 MW per interval. A five-minute CTS with SPP would have achieved more than $44 million in production cost savings with a similar level of adjustments.

Table 14: CTS with Five-Minute Clearing Versus Current CTS
2021

	Percent of Intervals Adjusted	Production Cost Savings	Profits	Percent Unprofitable
PJM				
Current CTS	9.7%	$7,203,734	$199,456	39.4%
5-Minute CTS	77.5%	$23,207,329	$11,765,360	13.8%
SPP				
5-Minute CTS*	89.6%	$44,089,866	$25,984,814	22.1%

* Results omit Feb. 13-19 when SPP experienced very high prices from the Arctic Event.

The improvement in the incentives for participants to utilize the CTS process is also notable. The CTS participants would have earned over $7 million from the cleared CTS transactions with PJM compared to much smaller gains in 2021 of $200,000 under the current process. In fact, more than 40 percent of the current CTS transactions are ultimately unprofitable versus less than 14 percent under the recommended process. These losses are evidence of the poor price forecasts that govern the adjustments currently. Five-minute CTS in SPP would have been even more profitable for participants, producing profits of nearly $26 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 improvement in the CTS process with PJM and implement this approach with SPP.

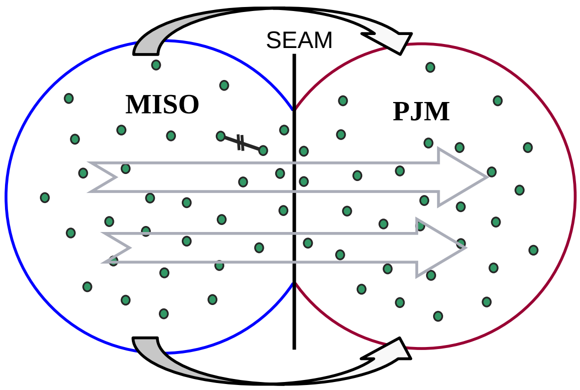
C. Interface Pricing and External Transactions

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

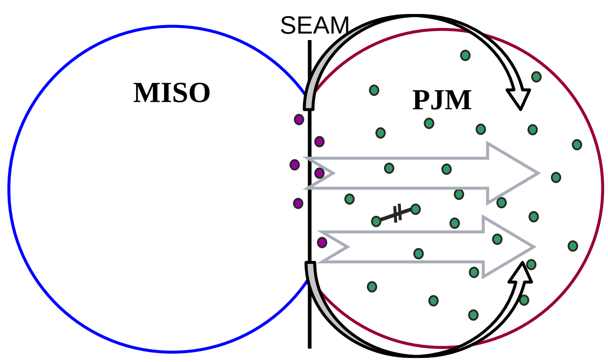
Establishing efficient interface prices would be simple in the absence of transmission congestion and losses—each RTO would simply post the interface price as the cost of the marginal resource on its system (the system marginal price, or "SMP"). Participants would respond by scheduling from the lower-cost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

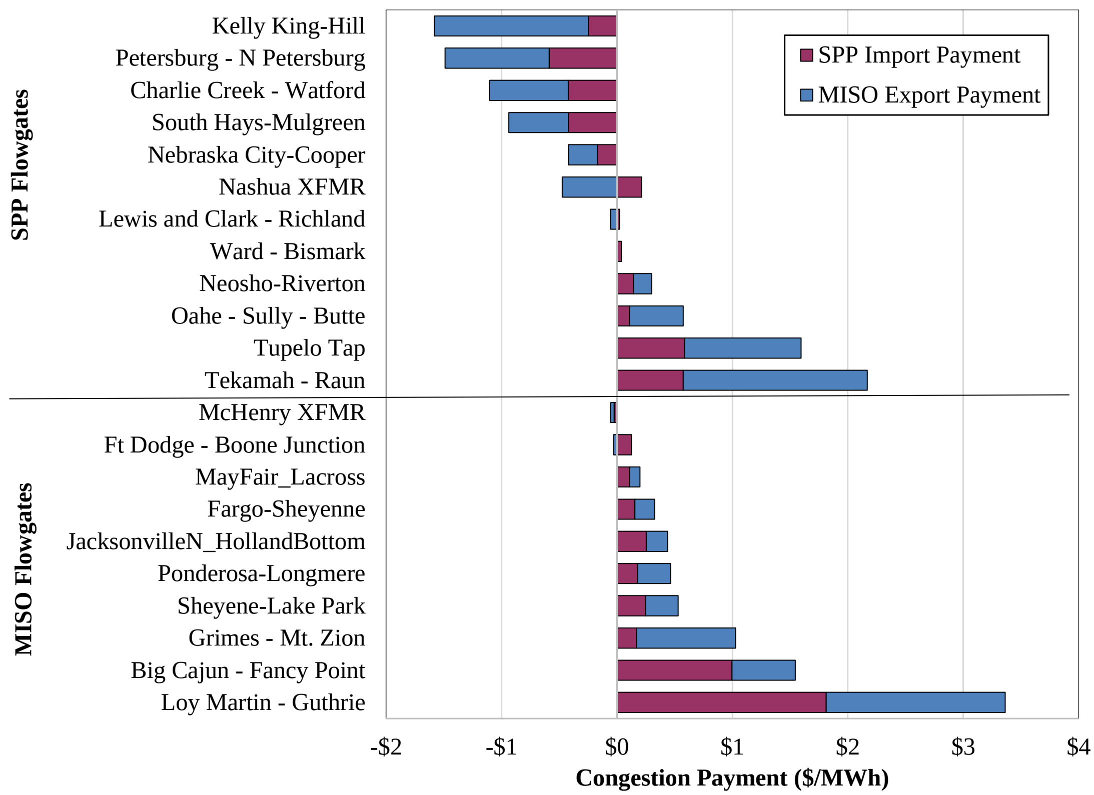


We have identified the location of MISO's marginal generators and confirmed that they are distributed *throughout* MISO, so we are concerned that the common interface definition sets inefficient interface prices. Our interface pricing studies show that in aggregate, the common interface has led to larger 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 in collaboration with the SPP MMU. We have 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 44 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 44: 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. Because MISO receives no credit for this relief and no reimbursements for the millions of dollars in costs it incurs each year, 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 2021. 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 (639) but very high in some local areas, such as WUMS (3850) and the South Region (4113), where a single supplier operates more than 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.
- Nearly all of the binding constraints into the two MISO South NCAs and the two Midwest NCAs had at least one pivotal supplier.

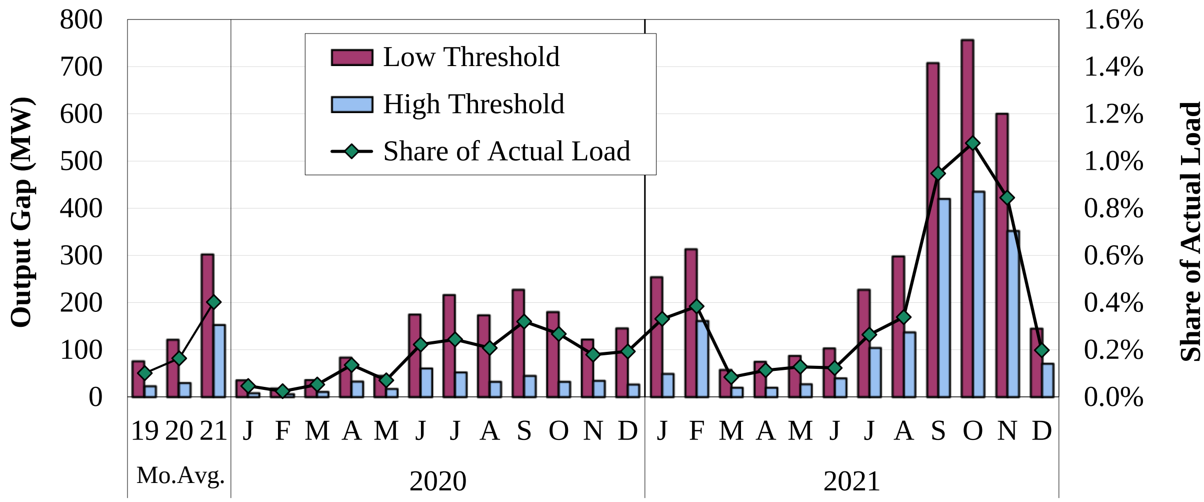
Overall, these results indicate that local market power persists, with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

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 -0.3 percent in 2021. The mark-up was negative because the monthly mark-up was -18 percent in February when gas resources’ costs were affected by extraordinarily high natural gas prices. But for this arctic event, the mark-up would have been slightly positive. The small average mark-up indicates that MISO’s energy markets produced very competitive results.

Figure 45 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 mitigation threshold (the “high threshold”) and a “low threshold” equal to one-half of the conduct mitigation 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 45: Economic Withholding – Output Gap Analysis
2020–2021



Low Threshold Results by Unit Status (MW)

Offline	12	8	38	0	0	0	0	3	12	36	18	4	8	10	2	0	90	3	0	9	8	27	46	129	103	35	9
Online	64	114	264	36	18	36	84	42	163	180	156	223	172	112	144	254	223	55	75	79	96	201	252	577	652	565	136

High Threshold Results by Unit Status (MW)

Offline	10	7	28	0	0	0	0	3	11	31	16	4	7	7	2	0	70	2	0	8	7	22	38	98	62	19	7
Online	13	23	125	9	7	11	33	15	50	21	17	41	25	28	25	49	91	18	20	20	33	82	100	322	373	333	64

The figure shows that the average monthly output gap level was 0.4 percent of load in 2021, which is effectively *de minimus*. The figure shows that the output gap rose slightly from 2020, which is largely attributable to coal conservation measures that multiple resources employed to ensure that they would have sufficient fuel inventory going into the winter months. 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 2021 effectively limited the exercise of market power. Mitigation in the energy market remained infrequent. However, during the Winter Storm Uri arctic event, real-time market mitigation measures were used to enforce the $1,000 per MWh soft offer cap and $2,000 per MWh hard offer caps when gas prices exceeded $200 per MMBTU in multiple locations. 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 conduct threshold of $25 per MWh is used for Dynamic NCAs. In 2021, no Dynamic NCAs were declared. The lower NCA thresholds generally lead to more frequent mitigation in NCAs, even though there are many more BCAs.

The incidence of mitigation was unchanged in 2021, affecting less than one percent of real-time market hours. Assuming the real-time market is effectively mitigated, the day-ahead market should not be vulnerable to the exercise of market power as long as it is liquid, with fulsome participation by physical and virtual trading participants. Hence, mitigation was only applied on three day-ahead market days in 2021. Market power mitigation in MISO's energy market remained infrequent because conduct was generally competitive.

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 these needs.

Average day-ahead RSG mitigation was much higher in 2021, largely because of nearly $10 million of day-ahead RSG mitigation that occurred during the Winter Storm Uri arctic event. Excluding February, day-ahead RSG mitigation increased by roughly 200 percent. While some of this increase was due to higher gas prices, more than $4 million of day-ahead RSG was mitigated during July and August for units committed for VLR in the Western Load Pocket. Average monthly real-time RSG mitigation fell 60 percent in 2021.

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 15 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:[47]

- Load-Modifying Resources (LMRs) that are capacity resources obliged 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 not obliged to offer and do not satisfy PRMR.

As shown in Table 15, MISO had more than 12 GW of DR capability available in 2021, a ten percent reduction from 2020. This decrease is largely the result of no Energy Efficiency (EE) Resources clearing the 2021–2022 PRA, discussed below, and fewer Emergency Demand Response resources. 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.

47 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 15: Demand Response Capability in MISO and Neighboring RTOs
2019–2021

		2019	2020	2021
MISO[1]		**12,521**	**13,528**	**12,197**
	LMR-BTMG	4,097	3,892	4,068
	LMR-DR	7,372	7,557	7,152
	LMR-EE	312	650	0
	DRR Type I	520	739	711
	DRR Type II	101	101	115
	Total Cross-Registered as LMR	*386*	*381*	*476*
	Emergency DR	934	1,439	785
	Total Cross-Registered as LMR	*428*	*470*	*158*
NYISO[2]		**1,288**	**1,199**	**1,170**
	Special Case Resources - Capacity	1,282	1,195	1,168
	Emergency DR	6	4	2
	Day-Ahead DRP	0	0	0
ISO-NE[3]		**3,309**	**3,686**	**3,928**
	RT DR Resources/DR Assets	321	433	397
	On-Peak Demand Resources	2,440	2,672	2,932
	Seasonal Peak Demand Resources	548	581	599

[1] Registered as of December 2021. All units are MW.
[2] Registered as of July 2021. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.
[3] Seasonal audited capabilty as of December 1, 2021. Source: ISO-NE Demand Response Working Group Presentation.

MISO's DR capability exhibits varying degrees of responsiveness to prevailing system conditions. The first and largest category of DR (accounting for almost 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 in those categories.

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. These legacy demand-side programs are administered by LSEs, 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 price mechanism. In the PRA, MISO classifies interruptible load resources as LMR-DR and BTMG resources as LMR-BTMG. As shown in Table 15, 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 15 shows, this category comprises only a small portion of MISO's total DR capability. These resources can participate in the energy, ancillary services, and capacity markets. Most opt to participate in the capacity markets as LMRs, which lessens the likelihood of curtailing 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.[48]
- 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 98 percent of DRR scheduling in 2021. The scheduling of these resources and the associated payments to them increased sharply in 2021. These large increases in scheduled demand reductions and payments in recent years brought to light concerns regarding the baseline calculations that factor into DRR Type I compensation. The "baseline" is the level of energy consumption MISO assumes will occur if the DRR curtailment offer is not scheduled. When it is scheduled, consumption below the baseline is assumed to be a curtailment and is the basis for its settlement. We discuss our concerns with the approach in subsection B.

Emergency DRs

The third category of DR is Emergency DRs (EDR), which amounted to 785 MW in 2021. These DRs do not have a must-offer requirement unless cross-registered and cleared as an LMR in the PRA. DR resources that qualify for and clear MISO's PRA can offer as EDRs rather than LMRs during emergencies. These resources specify their availability and costs in the day-ahead timeframe. If an emergency ensues in real time, MISO selects EDR offers in economic merit

48 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.

order based on the offered curtailment prices up to $3,500 per MWh. EDR participants who curtail their demand are compensated at the greater of the prevailing real-time LMP or their offered costs (including shut down costs) for the verifiable demand reduction provided. Unlike LMRs, EDRs can set prices with their offers during emergencies.

Finally, DR resources may count toward fulfillment of an LSE's PRMR if the resource can curtail load within 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 phase in across multiple planning years, starting in 2022–2023, to allow participants to modify existing contracts and replace affected capacity.[49]

Prior to 2017, LMRs had not been called in MISO since 2007. They have, however, become increasingly important in both planning and operations during emergency events. From April 2017 through June 2021, LMRs were deployed eight times in MISO South and three times in MISO Midwest. Four of these deployments occurred in January 2018 and 2019 because of unusually cold temperatures. More recently, three deployments occurred in February 2021 during the Winter Storm Uri arctic event and one deployment occurred in June 2021 in the Midwest, when MISO declared a Maximum Generation Event Step 2. We discuss the 2021 emergency events in detail in Section II.E of this Report.

B. DRR Participation in Energy and Ancillary Services Markets

As discussed above, DRR settlements increased substantially in 2021 to almost $38 million, up from roughly $14 million in 2020. We initiated an investigation of this increase and found that these outcomes raise significant concerns regarding the market design and rules, the inefficient incentives they provide, and the resulting participant conduct. In particular, 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 activities. 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 times 100 MW per hour for providing nothing to the system.

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,

49 Beginning in the 2022-2023 PRA, LMRs that register with six hours or less notification time and can provide curtailments at least ten times per year will be able to fully qualify as capacity resources, and LMRs with longer registered lead times and fewer curtailments will have proportionally less capacity.

which will cause their curtailment offer to be scheduled and the hour to be excluded from the baseline. The participants can then simply not offer the curtailment when its load is highest, causing the baseline to substantially exceed the participants' typical consumption for the DRR resource. Having established the inflated baseline, the participant can then return to offering curtailments as a price-taker when consuming at typical levels and be paid for the difference between the peak load level and the typical load level. For example, assume:

- Peak load equals = 100 MW and typical load = 75 MW.
- DRR resource offers 25 MW as a price taker in most hours, except in those when the participant will be consuming 100 MW.
- Baseline is set at 100 MW and the participant's 25 MW curtailment offers (priced low to ensure they are always schedule) will clear and the participant will be paid for 25 MW of curtailments for doing nothing.

These two strategies are involved in the vast majority of payments to DRR Type 1 resources. Figure 46 below shows all payments to such resources over the past three years. It separates the payments to those that are associated with the first strategy (payments for artificial curtailments), the second strategy (inflated baselines) and legitimate payments for energy curtailments and ancillary services.

Figure 46: Energy Market Payments to DRR Type I Resources
2019–2021

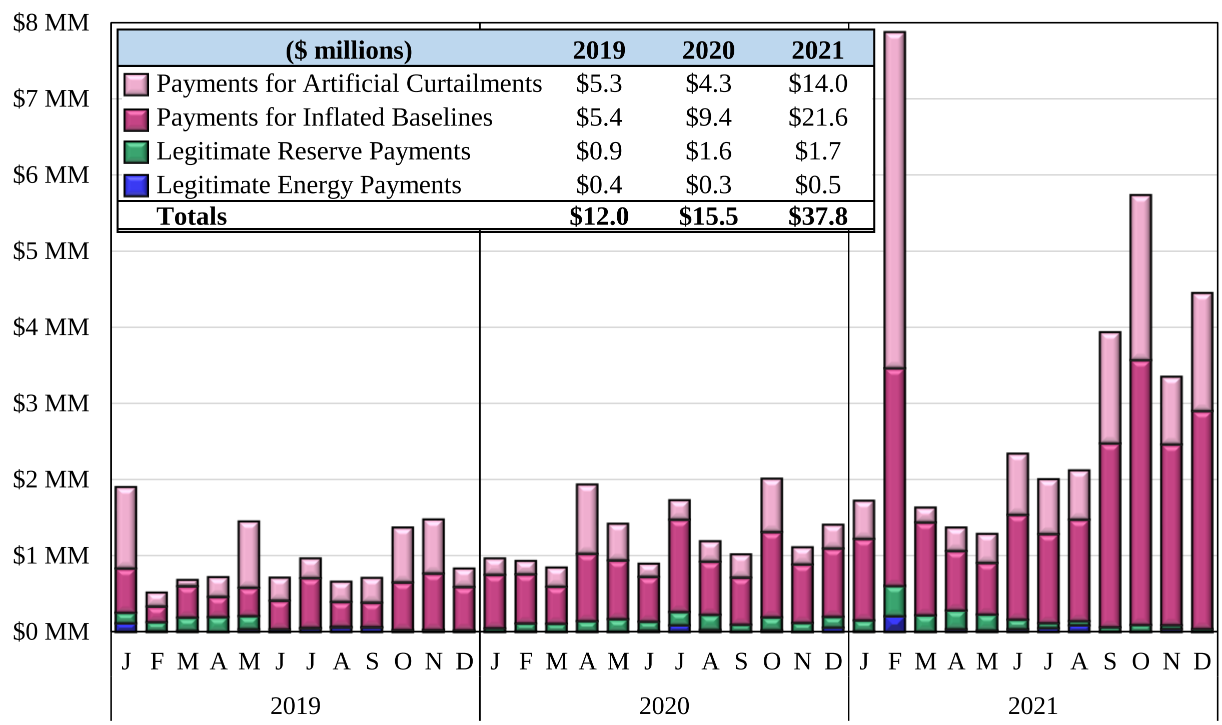


Figure 46 shows that the payments to DRR resources have risen sharply over the past three years with virtually all increase attributable to the two strategies described above. We found that less than 6 percent of the payments in 2021 were legitimate.

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 DRR resource result in real curtailments. We recommend two potential improvements that would help achieve these objectives:

- DRR resources should be obligated to submit their anticipated consumption absent any curtailments. The settlements could then be based on the lower of this value and the currently calculated baseline. This anticipated consumption data could be monitored and evaluated to identify when a participant submitted false or misleading data to inflate its settlements.
- MISO should 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. Offering curtailments at prices substantially higher than expected or typical real-time prices can be reasonable, but 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.

C. Energy Efficiency in MISO's Capacity Market

When demand-side resources were introduced in MISO's capacity markets, MISO also allowed energy efficiency (EE) to qualify to provide capacity. The quantity of EE participating in the PRA grew rapidly and was playing an increasingly important role in satisfying MISO's resource adequacy needs until the 2021/2022 PRA, when the sole participating provider of EE was disqualified. Table 16 summarizes the EE quantities over the past five PRAs. In the 2021/2022 and 2022/2023 auctions, no EE resources cleared the capacity auction because MISO did not qualify the EE that attempted to participate.

Table 16: 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

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. Given the rapid growth in EE capacity, it is important that providing credits to EE is justified and that the accreditation of EE is accurate.

In early 2021, the IMM performed an audit of EE capacity that had been sold in the PRA in prior years. Based on this audit, we found the EE resources did not actually cause any reductions in MISO's peak demand, and the associated capacity accreditation grossly overstated the reliability value of the EE resources.

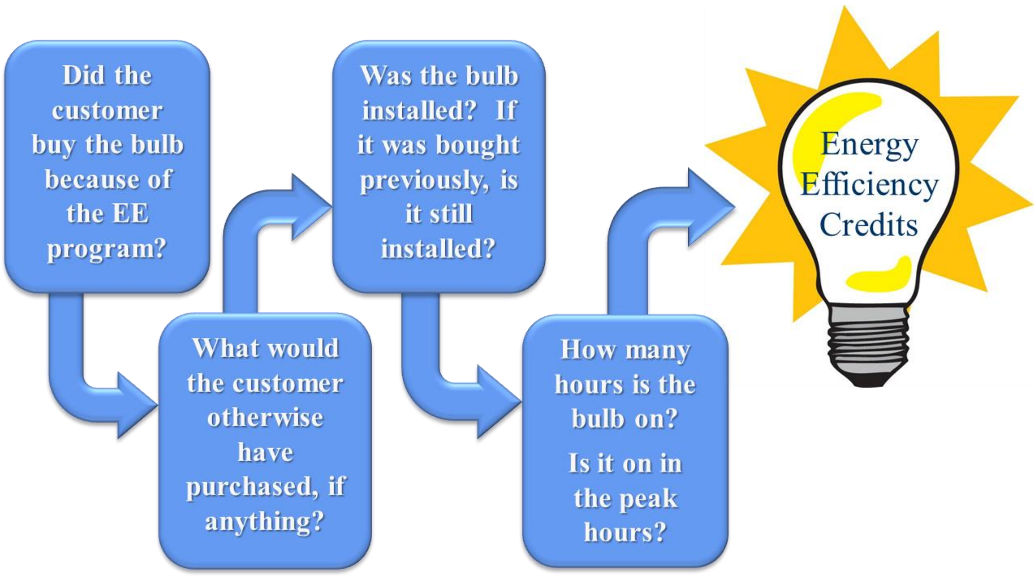
- Virtually all of the claimed savings were related to typical products being purchased by retail customers for which the EE participant had no effect in precipitating the purchases.
- In other words, the product purchases would have occurred with or without the EE resource and, therefore, would have already been accounted for in MISO's load forecast.
- The capacity payments were not used to provide meaningful incentives to customers to increase the sales of EE products.
- The claimed savings were not reasonably verified as required under Attachment UU of the MISO Tariff.

MISO validated these findings and ultimately disqualified the EE from participating in the 2021/2022 PRA. This action resolves our concerns about the conduct described above. We still recommend that MISO revise its Tariff to strengthen the requirements and validation processes to ensure that only legitimate EE resources are qualified in the future.

Making these Tariff improvements are the highest priority in the short-term, but we still recommend that MISO not allow EE resources to participate in the capacity market for three reasons.

Economic Justification for EE Participation. Making payments to customers directly or to intermediaries that facilitate EE investments is justified to the extent that such payments are efficient and lead to more economically efficient EE investments. Absent MISO's EE program, customers have efficient incentives to make investments in energy efficient technologies because of the savings they receive via lower electricity bills. Since electricity rates should include both the energy and capacity costs of serving retail customers, the savings customers receive when investing in EE should reflect the full value of the savings to MISO system. Moreover, in some MISO states utilities are provided a further incentive for such savings via tax credits and rebates. Therefore, making capacity payments for assumed load reductions essentially double-compensates such customers and is, therefore, not efficient or necessary.

Accuracy of EE Accreditation. Even were such payments justified, MISO must be able to accurately calculate how much the load has been reduced by EE in peak hours. Unfortunately, this is not possible because MISO must make an array of speculative assumptions as illustrated below for a lighting program. Although MISO has attempted to make the most reasonable assumptions possible, the resulting capacity credits are unlikely to be accurate. This why EE is not comparable to any other capacity resources. All other resources can be tested and verified to provide a basis for their expected performance in maintaining reliability. Although there is some uncertainty regarding their availability, the uncertainty regarding EE credits is much higher. Hence, EE is not comparable to other resources and should not be qualified to sell capacity.



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 investments by explicitly grossing up their forecasts to counter the effect of EE measures. If the capacity requirements of the LSE in question fall as peak load falls, it will receive a windfall at the expense of other MISO customers. MISO acknowledges this concern by limiting the period in which an EE measure is awarded capacity to the initial deployment year and three subsequent periods.

Nonetheless, since MISO's EE program is not addressing a known economic inefficiency, we recommend MISO disqualify EE measures from participating in MISO's capacity auction.

X. Recommendations

Although MISO's markets continued to perform competitively and efficiently in 2021 overall, we recommend a number of improvements in MISO's market design and operating procedures. These twenty-eight recommendations are organized by the aspects of the market that they affect:

- Energy Pricing and Transmission Congestion: 10 total, 2 new.
- Operating Reserves and Guarantee Payments: 3 total, 1 new.
- Dispatch Efficiency and Real-Time Market Operations: 9 total, 2 new.
- Resource Adequacy: 6 total, 0 new.

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

MISO addressed seven 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 Pricing and 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, which is the objective of the recommendations in this subsection.

2021-1: MISO should 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 and 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 done on a regular basis 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 should be expanded to relieve costly binding constraints that are generating substantial congestion costs.

In our *Summer 2021 Quarterly Report*, we presented an analysis of one constraint that generated over $57 million in congestion during the 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 roughly 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 recommend 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 in MISO and lowering the associated costs for MISO's customers.

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

2021-2: MISO should 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. 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 prices and would not contribute to setting real-time energy 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: This is a new recommendation. After initial discussions, MISO has indicated agreement on the problem identified, but that prototyping of potential software solutions will be needed.

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 of 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 not converging 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".

To address these issues in the short term, we recommend that MISO base relief requests on the RTOs' respective shadow prices and implement an automated means to control for 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 solution using "predicted" UDS flow. MISO has implemented this approach on a subset of flowgates and believes initial results of dampening oscillations warrant further trials on more flowgates. MISO believes the IMM solution, though likely better, will require more significant changes and therefore is not currently pursuing it. Unfortunately, the near-term approach is not likely to increase relief requests when they are too low on a sustained basis. This issue is being tracked on the Issue Tracking Tool under MSC014.

Next Steps: MISO will continue to expand the set of flowgates being evaluated and expects to further enhance the approach by using the NMRTO's predicted flow rather than market flow. We encourage MISO to consider additional changes that will address the concerns we have raised in this area.

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

The original intent 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 constraint will be identified as a M2M constraint when the NMRTO has:

- a generator with a shift factor greater than 5 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 and has indicated that it will evaluate the IMM's recommended solutions and their effects on the administration of JOAs. However, MISO has put this recommendation as a low priority and will resume discussions after completion of the update to the Freeze Date Firm Flow Entitlement (FFE) methodology. We believe this recommendation is unrelated to the FFE methodology and encourage MISO to address it in a timelier manner. This recommendation is being tracked under MSC-2021-2.

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 ratings from transmission facilities

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. 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 report identifies key recommended enhancements, including:

1. System Flexibility: MISO should enable more rapid additions of new elements to AAR programs.
2. Forward Identification: MISO should support identification of 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. In 2020, MISO implemented changes to shorten the lead-time on adding AARs in real time. MISO is scoping additional solutions under the MSE project for forecasted ratings, but no solutions have been prioritized for development. In late 2021, FERC issued Order 881 requiring use of AARs and Emergency Ratings in real-time and forecasted ratings in the day-ahead. It also requires transmission owners provide rating methodologies to RTO/ISOs and their market monitors. MISO is developing compliance plans in response to Order 881 that will hopefully fully address this recommendation. We have provided a detailed list of data that we recommend MISO collect to establish its capability to validate transmission ratings provided by transmission owners and will be reviewing the other aspects of MISO's Order 881 compliance plans. This recommendation maps to Issue RSC-20180-54 A and B and is a high priority.

Next Steps: MISO should complete its compliance plans for 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.

2016-1: 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 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 resulting prices will send more efficient signals for participants to take actions in response to the shortage, which 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 $20,000 per MWh. Although the ORDC should be based on this VOLL, it would be reasonable to allow the ORDC to plateau at a lower price level for deep shortages, such as $10,000 per MWh. Although this price may seem high, almost all of MISO's shortages are likely to be in ranges that would establish shortage prices between $100 and $2,000 per MWh.

Status: MISO agrees with the recommendation and this item is currently classified as a high priority by MISO in the Integrated Roadmap.[50] Stakeholder discussions regarding VOLL levels and scarcity pricing began in 2020. An evaluation whitepaper was published in May of 2021, but no further reforms to the ORDC and VOLL are anticipated until 2023 or later.[51]

Next Steps: MISO has no plans to continue to evaluate VOLL estimation methods with stakeholders in the near-term, but MISO has agreed that a value higher than $3500 is appropriate. Because 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 software changes or substantial additional resources, MISO should address this recommendation in 2022.

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 2021, multiple simultaneous generation outages contributed to more than $844 million in real-time congestion costs—at 30 percent of real-time congestion costs, indicating large potential savings.

50 Continued Reforms to Improve Scarcity Pricing and Price Formation, IR071.

51 https://cdn.misoenergy.org/20210513%20MSC%20Item%20XX%20Scarcity%20Pricing%20Evaluation%20Paper550162.pdf

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.[52] We recommend MISO expand its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages.

Status: MISO's consideration of this recommendation has been inactive. MISO has not sought additional outage coordination authority. Economic considerations for outage coordination continue to be in the RAN work plan. The current target within MISO to start scoping is 2024, although MISO has begun considering approaches for how to conduct economic evaluations of outages.

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

2014-3: Improve external congestion related to TLRs by developing redispatch agreements with TVA and IESO

As noted in prior years, the integration of MISO South has increased the frequency of TLRs called by TVA (both for the TVA area and the AECI area that TVA coordinates). In 2020 and 2021, there were also a number of costly TLRs called by IESO, resulting in substantial curtailments of imports from PJM. These TLRs resulted 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. Implementing a redispatch agreement would likely improve both the efficiency and effectiveness of congestion management on TVA or IESO facilities that are affected by MISO.

Status: MISO agrees with this recommendation and has had discussions with both IESO and TVA to address these transmission-coordination and TLR issues in recent years. MISO plans to seek agreement with IESO to implement an enhanced congestion management construct like market-to-market in IESO's reformed Market Renewal Program (MRP) expected in 2022. MISO also plans to have further discussions with TVA to propose a redispatch agreement that may be enabled by TVA's new system operations center and EMS, expected in 2024. MISO is also working to implement the Parallel Flow Visualization (PFV), which MISO implemented in early June. Likewise, MISO has been actively working with IESO to develop procedures to ensure better coordination.

52 ISO-NE Market Rules: Section III, Market Rule 1 – Appendix G; June 25, 2012 FERC Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency, Presentation by ISO-NE.

Next Steps: We continue to monitor for and evaluate the negative impacts on MISO's markets and customers caused by TLRs. MISO should continue to attempt to negotiate redispatch agreements with both TVA and IESO that will allow economic coordination and redispatch to efficiently manage congestion on their respective systems.

2012-3: Remove external congestion from interface prices

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

Status: This recommendation was originally made in our *2012 State of the Market Report.* MISO has indicated agreement that external interface pricing would be improved by eliminating external congestion on all interfaces. Nonetheless, MISO has no plans to address this recommendation until after implementation of the Market Systems Enhancement. 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 review this topic in the Seams Management Working Group and develop the workplan necessary to modify its interface prices as part 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 product enabling participants to arbitrage congestion spreads in a price-sensitive manner would be more effective and efficient. Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (i.e., by scheduling a transaction). This would reduce the risk participants currently face when they submit a price-insensitive transaction and avoid inefficient day-ahead congestion.

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. Hence, this recommendation is a Parking Lot item in the Roadmap pending performance enhancements from the MSE.[53] The IMM continues to encourage MISO to reconsider this recommendation upon completion of the MSE.

B. Operating Reserves and Guarantee Payments

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.

2021-3: MISO should evaluate and reform their unit commitment processes

This report indicates that out-of-market commitments by MISO and the associated RSG costs increased substantially in 2021. Our analysis indicated that most of these commitments were not ultimately needed to satisfy MISO's energy, operating reserves, and other reliability needs. Some of these commitments were made on a sustained basis to satisfy VLR requirements in a load pocket area where a large combined-cycle generator began operating in early 2021. A process is only now underway to update the operating guide for this area to account for this new resource, which will likely greatly reduce the VLR commitments and costs in this area. Finally, RSG costs were inflated in some periods because operators' commitment decisions that were not informed by the actual offer costs that MISO would have to guarantee associated with the commitment. This occurs when MISO makes long-lead commitments and resources' day-ahead offer costs are guaranteed but MISO operators base decisions on real time offers that can vary substantially from the day-ahead offers, or in cases when the offer caps are binding and the operators cannot see the costs in excess of the cap that will be guaranteed.

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

1. Continue to critically evaluate its tools, procedures, and the criteria used to determine when out-of-market commitments are warranted.

53 Introduce a Virtual Spread Product, IR005.

2. Ensure that operators can observe the relevant offer costs that MISO will guarantee associated with each out-of-market commitment.
3. Update VLR operating guides in a timely manner when resources enter or exit the VLR area or transmission upgrades are made that affect the VLR area.

Status: This is a new recommendation. MISO's initial response indicated agreement with the problem and the need to consider priority and timing of efforts.

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 and reduce RSG. The resources that would provide 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 on the issue and believes enhancements to its Ramp Product and new Short-Term Reserve product will help. 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 being tracked on the Issue Tracking Tool under MSC-2021-9 and is ranked with medium priority.

Next Steps: MISO should complete its evaluations and prioritize the design and implementation of both an uncertainty product in the current software.

2018-3: Improve the RDT Agreement to procure reserves on the RDT and compensate the joint parties when the reserves are deployed

Regional emergency events have sometimes caused MISO to exceed the RDT. To avoid this in the future, MISO will hold regional reserves that will better allow it to respond to regional system contingencies. While we recommended these changes in MISO's reserve markets, MISO should also consider procuring these regional reserves on the RDT from the joint parties. For example, if the RDT limit is 3,000 MW, the parties could agree to sell 500 MW of reserves (allowing MISO to flow 3,500 MW after a contingency). In return, MISO would pay the joint parties the clearing price for regional reserves and pay for the deployment of the reserves. These costs would naturally be collected through the real-time market as the flows over the RDT rise. Importantly, MISO has developed a tool to identify the quantity of reserves that may be deployed given the flows that the deployment would cause on the joint parties' transmission systems.

Status: MISO agrees there could be potential benefits of this recommendation, but it will require agreement with SPP and the Joint Parties, and in discussions during 2021 MISO indicated the Joint Parties had minimal interest in this recommendation. MISO does not currently plan to continue including this recommendation.

Next Steps: Seek agreement as MISO completes the discussions on RDT Agreement.

C. Dispatch Efficiency and Real-Time Market 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.

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 in MISO, the need to manage extraordinary 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.

Status: This is a new recommendation. MISO has indicated agreement with the problem and that work is ongoing on LAC improvement that is intended to inform future work on a look ahead dispatch.

2021-5: MISO should 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. Some of this was due to conduct of the resources, while some is due to suboptimal Tariff and settlement rules. Changes and clarifications in these rules will address both of 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 that 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: This is a new recommendation. MISO had indicated agreement with some of the issues identified but that further evaluation is needed. MISO has suggested removing this recommendation and adding it to 2019-5. MISO believes measuring and verifying the response of demand resources is measuring the counterfactual (i.e., what load would have been but for the call by MISO to dispatch down), and that it is appropriate to revisit the measurement and verification protocols codified in Attachment TT of the Tariff. These protocols were drafted by NAESB, adopted by reference by FERC and accepted by FERC as part of MISO's Tariff. Since these NAESB standards were adopted over a decade ago, there have been improvements in trying to measure the counterfactual, like difference-in-difference approaches. MISO requires further evaluation to investigate and frame the issue and evaluate any next steps, including an evaluation of requirements of FERC Order 2222 on DERs.

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 substantially the same regardless of whether operators decide to declare a transmission emergency or a capacity emergency.

This difference was most starkly observed in the Western load pocket in MISO South, which experienced load shedding twice over the past two years. MISO declared a capacity emergency during Hurricane Laura on August 27, 2020 and prices were efficiently and appropriately set at VOLL ($3,500 per MWh) to reflect the marginal action of shedding load. In contrast, MISO declared a transmission emergency during the Arctic Event on February 15-16, 2021 and prices were inefficiently set well below VOLL. This reduced the market-based charges to the generators that tripped and caused the emergency by $23 million and reduced the compensation to the loads by $29 million. The divergence of these outcomes is a substantial concern and we recommend MISO bring alignment between the two types of emergencies by:

1. Reviewing the emergency actions available to operators during capacity emergencies and identify those that could be applicable during transmission emergencies. An example would include curtailing non-firm external transactions that could have provided relief for some of the transmission emergencies that occurred on February 16, 2021.

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 affected area, increasing the Post Reserve Deployment Constraint Demand Curves to achieve efficient local emergency pricing.

Status: MISO agrees emergency procedures should include all appropriate reliability actions and tools for managing the system under different types of emergencies. In 2021, MISO made related filings on emergency actions and updated some of its procedures to improve its emergency actions and its Reserve Zone definitions to reflect emergency conditions. This will allow more timely responses to emergency conditions.

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.

2020-3 Remove eligibility for wind resources to provide ramp product

Wind resources are currently qualified to supply MISO's ramp product. However, because ramp offers are cleared currently at a $5 maximum, a unit can clear only when the LMP is within $5 of the unit's marginal energy cost. The marginal cost for wind units are generally less than or equal to zero. Hence, a wind unit will be selected for ramp only when the LMP is less than $5 per MWh. Typically, this only occurs when wind units are dispatched down for congestion. This makes wind units a poor option to provide the ramp product because they will generally be pushing into transmission constraints if MISO attempts to ramp them up. Therefore, we recommend that MISO remove eligibility for wind resources to provide the ramp product. This will improve the performance of the ramp product by causing MISO to procure ramp capability from other types of resources that are better suppliers of ramp.

Status: MISO agrees with the IMM's description of the issue, specifically that wind resources will typically only clear Up Ramp Capability product capacity when they are dispatched down for congestion. Hence, the cleared capacity would not be deployable by the UDS and potentially masking shortages of rampable capacity needed to manage uncertainty.

Next Steps: MISO is not prioritizing detailed design and implementation work in 2022 given other priorities and its belief that this would require changes to registration and the market clearing engines. However, we have spoken with technical staff at MISO that have confirmed that this recommendation can be implemented via a configurable parameter with changes to the software. Therefore, MISO should re-visit the near-term implementation of this recommendation.

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 $20 million, which are much larger than can be achieved by improving the current process.

Status: MISO agrees 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 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.

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

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

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

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

Next Steps: 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, and to log the emergency determinations and actions.

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 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 charges are a significant factor. However, MISO continues to favor addressing other factors, including reducing the forecasting errors. This item (IR066) was placed in the Integrated Roadmap Parking Lot in 2018 and was inactive in 2021. MISO does not anticipate any activity in 2022. We believe 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 have very significant impacts on 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 it is necessary for operators to perform all these actions, 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.
- 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 lead to 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: MISO has made improvements in logging features within the current MCS and has put more emphasis on training for operators to facilitate clear and concise log entries. The Reliability Portfolio efforts identified operator logging as a key focus area under Mission Critical Communication. MISO indicates that requirement gathering for further enhancements to the operator logging functionality in MCS has begun and will be prioritized as part of the portfolio road-mapping efforts and that IMM recommendations will be considered in this effort.

Next Steps: MISO and IMM staff will continue to work on identifying additional logging needs. MISO expects to complete appropriate designs for future logging processes by mid-2022, including what operator logging should occur through the MCS or through separate systems.

2016-6: Improve the accuracy of the 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 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. However, MISO has not devoted sufficient resources yet to identifying the causes of inaccurate LAC recommendations. This recommendation maps to issue IR008.

Next Steps: MISO indicates it will develop an improvement plan to be implemented in late 2022 or 2023. This will require MISO to commit staff resources to this effort, which we believe will be a valuable allocation of resources. Once the LAC is performing sufficiently well, we recommend improvements to MISO's procedures to increase adherence to the LAC recommendations.

D. Resource Adequacy and Planning

Reasonable resource adequacy requirements and a well-functioning capacity auction are intended to facilitate efficient investment and retirement decisions. The accuracy of economic signals from the MISO markets have 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 most recent 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 the resources over the long term.

2020-4 Develop ELCC methodologies to accredit DERs, LMRs, battery, and solar resources

The ELCC represents the amount of the planning resource requirements that a resource is capable of supplying. Such a methodology is needed for intermittent resources because the amount that it will be producing in peak hours is highly variable and uncertain. Therefore, an ELCC methodology was developed for wind resources that allows wind resources to provide planning resources at a rate of approximately 15 percent of their nameplate output level on average. Given the unique characteristics of DERs, battery resources, and solar resources, the availability-based accreditation that we propose for all other resource types would not always be accurate and likely highly variable for these resources. Therefore, we recommend that MISO develop ELCC methodologies that result in accurate accreditation levels for these resource types.

Status: MISO agrees with developing improved accreditation methodologies for intermittent resources and other non-conventional resources. MISO plans to evaluate the IMM's recommended ELCC methodology along with other potential solutions to more accurately accredit these resource types based on their reliability contributions during times of need. MISO plans to initiate work on this issue following the current FERC filing of seasonal and other Resource Adequacy construct reforms.

Next Steps: Initiate evaluation of improved accreditation methodologies.

2019-5: Remove eligibility of Energy Efficiency to sell capacity or improve the Tariff rules governing EE and their enforcement

The increasing levels of 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. Further, EE resources have often not satisfied the measurement and verification standards under the Tariff. Hence, EE resources to date have yielded very little real benefits.

Further, to the extent that the market payments are used to subsidize consumer purchases of energy efficient products, it is an inefficient subsidy of actions that customers have sufficient incentives to undertake. Retail electric rates include *all* the costs of serving the customer, including fixed transmission and distribution costs that do not decrease as consumption falls. Therefore, consumers' EE savings are generally higher than the value of the reductions to MISO. Additional incentives funded through MISO's capacity market, therefore, are extraneous.

Given these concerns, we recommend MISO terminate its rules allowing EE resources to sell capacity because EE resources are demonstrably not comparable to generation or other resources that legitimately provide capacity under Module E. In the alternative, 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 survey after installation.

Status: MISO intends to review the overall assumptions, requirements, and administration of Energy Efficiency Resources under Module E-1 of the Tariff through the stakeholder process. MISO indicates further evaluation to investigate and frame the issue and evaluate any next steps. This recommendation is currently assigned a low priority. This recommendation is being tracked on the Issue Tracking Tool under RASC 2021-4.

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

2017-7: Establish PRA capacity credits for emergency resources that 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: Tariff changes approved in August 2020 that are scheduled to be implemented in 2022 should improve the rules pertaining to LMRs by imposing tighter standards for notification times and call limits. In 2022, MISO will revisit LMRs and other emergency-only resources to develop an accreditation methodology based on their availability and the effects of the required emergency declaration. This recommendation has been aligned with IR025 (sub issue RASC009) and is deemed to be a high priority by MISO.

Next Steps: MISO should continue to develop possible alternatives for addressing this recommendation.

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

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

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

Status: MISO has not made progress in evaluating this recommendation. MISO intends to prioritize it after the conclusion of the discussions of a seasonal Planning Resource Auction.

Next Steps: MISO will need to 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, 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. Therefore, 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.

Status: Although MISO indicates that it agrees with the recommendation, it is not aligned with the MISO Roadmap Project and is currently in an inactive status.

Next Steps: We continue to encourage MISO to evaluate the benefits of improving the zonal capacity market definitions.

2010-14: Improve the modeling of demand in the PRA

The use of only a minimum requirement coupled with deficiency charges to represent demand in MISO's capacity market results in an implicit vertical demand curve for capacity. This does not efficiently reflect the reliability value of capacity and understates capacity prices as capacity levels continue to fall. This is particularly harmful as large quantities of resources are facing the decision to retire in response to prevailing market conditions. In this report, we identify more than 5 GW of economic resources that have retired prematurely primarily because of the grossly understated capacity prices produce by MISO's PRA. These uneconomic retirements have caused MISO's capacity levels in the Midwest region to fall below the minimum requirement in the 2022-2023 PRA, resulting in prices throughout the Midwest clearing at CONE.

This is evidence that implementing a reliability-based demand curve is required to satisfy MISO's Reliability Imperative. 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 capacity market moves toward the minimum planning reserve requirement. This report shows that this recommendation would lower the costs of satisfying the planning reserve requirements for both regulated and unregulated participants alike.

Understated capacity prices are particularly harmful to MISO's integrated utilities, most of which own surplus capacity and are compelled to sell it at inefficiently depressed prices. They are also problematic for unregulated participants that rely on the market to retain adequate resources to ensure reliability.

Status: This recommendation remains in inactive status. In past years, MISO has not been in agreement on this issue because it had lacked support among the states and MISO believes that resources adequacy is the states' responsibility. However, some states began to show some interest and MISO has indicated that it intends to evaluate this recommendation in 2022.

Next Steps: In light of renewed interest in this recommendation, MISO should work with the IMM, its stakeholders and OMS to move toward a consensus on the recommendation.

E. Recommendations Addressed by MISO

In this subsection, we discuss past recommendations that MISO has addressed since last year.

2014-5: Transition to seasonal capacity market procurements

Both the needs of the system and the available system supply change substantially from one season to the next. This can be recognized by clearing the PRA on a seasonal basis rather than on an annual basis as is currently the case. We have previously discussed the array of benefits such a change would generate and recommended that MISO implement a four-season market.

MISO filed a proposal with FERC in late 2021 to implement a seasonal planning resource auction to be conducted once per year. Although larger benefits could be achieved by also implementing seasonal auctions in advance of each season, the MISO proposal largely addresses this recommendation. We expect a FERC Order in early 2022.

2015-1: Improve ability for online resources to set prices in ELMP and suspend pricing by offline resources

MISO had partially implemented this recommendation in 2017 by allowing resources to set prices that can be started within 60 minutes, and in 2019 by allowing resources committed in the day-ahead market to set prices. These changes have resulted in significant improvements. We had also recommended that MISO improve ELMP by removing the ramp restriction that limits the ability of FSRs to set prices when they are the marginal source of supply in MISO. MISO proposed this improvement to its Tariff in its December 2020 Emergency Pricing filing.

Finally, we have continued to find that ELMP's offline pricing has generally resulted in inefficiently low ELMP prices during shortage conditions. MISO will continue to evaluate this issue has indicated that it will make changes to limit the scope of offline pricing in a manner that should address most of our concerns. Given the resolution to these issues and the plan to address offline pricing, we consider this recommendation resolved.

2015-2: Expand utilization of temperature-adjusted and emergency ratings for transmission facilities

For several years our analysis of transmission ratings submitted to MISO by transmission owners for use in MISO's real-time and day-ahead markets continues to show that few transmission owners are utilizing MISO's capability to accommodate AARs. We have found that the majority of transmission owners provide seasonal ratings only, and that seasonal ratings can be up to 30 percent lower than the ratings that may be reliably used based on actual ambient temperatures. Our analysis showed potential ARR congestion cost savings of $61 and $183 million in 2020 and 2021, respectively. Additionally, the TO agreement calls for transmission owners to provide emergency ratings, which can be 10 to 15 percent higher than the normal ratings. Our analysis shows potential savings in congestion costs from providing emergency ratings of $52 and $138 million in 2020 and 2021, respectively. Hence, we recommended MISO work with the TOs to provide and utilize AARs and emergency ratings, beginning with the most congested facilities.

MISO began working with transmission owners to voluntarily provide AARs and emergency ratings, but progress was limited and TO policies have restricted consideration to only AARs and generally excluded consideration of transformers without facility specific evaluations. In late 2021, FERC issued a Final Order that requires TOs to provide and that MISO to use AARs and Emergency Ratings.[54] MISO will be developing a compliance plan to file with FERC, and we anticipate providing feedback.

2018-1: Improve emergency pricing by establishing an efficient default floor and accurately accounting for emergency imports

Emergency pricing improves the efficiency of prices by reflecting the cost of meeting emergency conditions. This creates incentives to resolve the emergency and incent both availability and flexibility. Our evaluation of emergency pricing revealed that the default offer floors had not been established at reasonable levels, and that the model incorrectly calculated ex-post RDT flows when emergency interchange transactions scheduled during regional emergencies.

MISO agreed with our recommendation to implement specified emergency default floors that will result in price levels that reflect the severity of the emergency and to correct the flaw in the RDT flow calculation. In August 2020, MISO implemented changes to allow the pricing engine to calculate RDT flow (and resulting prices) that reflect proxy costs for emergency imports. MISO made a FERC filing late in 2020 to establish an efficient default floor for emergency offers. Once implemented, these changes will adequately address our key concerns.

2018-2: Lower GSF cutoff for constraints with limited relief

MISO employs a GSF cutoff of 1.5 percent to identify which generators to optimize in its dispatch when managing the flows on a transmission constraint. This limits the number of generators that are assumed to substantially affect the flows on a constraint and is done primarily to ensure that the dispatch model will solve in a reasonable amount of time. Unfortunately, there are a number of constraints where employing a 1.5 percent cutoff fails to engage most of the economic relief available to manage the constraint. Hence, it can significantly increase the costs of managing the constraints and diminish reliability. Therefore, we recommended that MISO reduce the GSF cutoff in its dispatch model and, if possible, in its commitment models as well. In late 2021, MISO began implementation of this recommendation by lowering the generator shift factor cutoff each three months. It has lowered it to 1.0 percent so far and observed no negative performance issues.

54 See Dockets No. RM20-16 and AD19-15 and Order 881 on Managing Transmission Line Ratings.

2018-5: Improve capacity accreditation by basing it on resource availability during tight supply periods

Accreditation is one of the largest opportunities for both short- and long-term improvements under Module E. We recommended MISO improve its accreditation methodology based on resource availability in the tightest margin hours. This would account for *all* outages and derates, as well as long start times and other inflexibilities. MISO filed proposed changes to address this recommendation in late 2021 and we anticipate a FERC Order in early 2022.

2018-6: Modify the supply and demand inputs for capacity by: a) accounting for behind-the-meter process load, b) improving planning assumptions, and c) validating suppliers' data

Calculating capacity requirements and supply accurately is key for the market to perform well. MISO made improvements in the three areas we identified:

1. MISO clarified the BPM-011 language to specify what level of firm process load should be reported by Generator Owners when submitting GVTC data.
2. MISO completed work in 2021 on its planning assumptions and now considers this item to be completed. MISO has collaborated with the IMM and stakeholders to improve planned outage assumptions in its LOLE model. The refined planned outage modeling was implemented in the planning year 2021–2022 LOLE analysis to determine the Planning Reserve Margin. MISO is working to implement an optimized outage methodology in the 2022–2023 planning year LOLE study for the zonal Local Reliability Requirements.
3. MISO has addressed its validation of the suppliers' data. MISO now has the staff, tools, and processes in place to validate the GVTC corrections.