# 2020 State of the Market Report for the MISO Electricity Markets

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**for the Midcontinent ISO**

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Corrections made on June 1, 2021 to previously published version of the report:

In Section VII.F, Figure 40 has been updated to reflect more accurate weighting of Zone 7 clearing at CONE in the 2020-2021 PRA. No corresponding language in the text has been changed.

In Section VII.G, Table 12 has been updated to more accurately distinguish between Retail Choice Suppliers and Vertically-Integrated LSEs to more accurately account for vertically-integrated utilities that are serving retail choice load. Corresponding text has been updated in the Executive Summary and in the Capacity Market Design subsection.

 

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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 *2020 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 2020

The MISO energy and ancillary services markets generally performed competitively in 2020. Multiple factors affected market outcomes in 2020, including the public response to COVID-19, a changing resource mix, and a continuing trend of significantly lower natural gas prices. The 22 percent reduction in natural gas prices combined with a 4 percent decrease in average load contributed to a 16 percent decrease in real-time energy prices throughout MISO, which averaged $22 per MWh in 2020.

Frequent transmission congestion often caused prices to diverge throughout MISO in 2020. The value of real-time congestion rose 26 percent in 2020 to $1.2 billion, in spite of lower gas prices, transmission upgrades, and the addition of a 1,000 MW combined-cycle unit in a frequently congested area the South. Key drivers of the congestion cost increase include:

- A large amount of continued investment in wind resources and corresponding growth in wind output, particularly during the fall months;
- Generation and transmission outages that occurred in Michigan during the summer months that caused severe congestion; and
- Extensive transmission outages caused by Hurricane Laura on August 27.

Real-time congestion in 2020 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;
- The use of a modeling parameter (the GSF cutoff) that makes economic relief from a large number of generators unavailable to MISO's dispatch model; 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 2020, indicating the markets were highly competitive.
- The "**output gap**" is a measure of potential economic withholding. It remained extremely low, averaging 0.16 percent of load. Consequently, market power mitigation measures were applied infrequently.

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

***Market Design Improvements in 2020***

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 2020 that will improve the performance of its markets.

- In January, FERC approved MISO's proposed Short-Term Reserves, which are scheduled to be implemented in December 2021.
- MISO implemented several changes that improved the qualifying of resources to participate in the Planning Resource Auction (PRA):
  - Resources that plan to be on outage for 90 of the first 120 days of the Planning Year cannot qualify to participate in the PRA;
  - LMRs' qualification requirements were improved so they are based on their registered lead time and the number of available calls throughout the year; and
  - Rules improved to ensure that the capacity offered by both conventional and intermittent resources are fully deliverable.
- In February and March, FERC approved a number of improvements to MISO's market power mitigation measures in Module D of its Tariff.[1]
- In March, FERC accepted Tariff changes to eliminate the relaxation of market-to-market constraints and changes to MISO's credit policies to reduce default risks.

In addition, MISO filed proposed changes in a number of other key areas:

- In December, MISO filed Tariff revisions to eliminate make-whole payments for resources deployed for spinning reserves in order to incent market participants to incorporate these expected deployment costs into their spinning reserve offers.
- MISO also filed significant changes to the Emergency Pricing Construct in December, which include raising the emergency offer floor prices, expanding the resources that can set prices during emergencies, and making other improvements to the pricing parameters.
- MISO also filed proposed Tariff changes requiring LMR availability to be updated continually and implementing penalties for failing to follow scheduling instructions.

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.

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1 FERC rejected Tariff changes that would have applied physical withholding mitigation measures to non-capacity resources in the day-ahead market.

### *Significant Events and Market Outcomes in 2020*

In 2020, the public response to the COVID-19 pandemic impacted MISO beginning in the spring, and MISO experienced multiple significant weather-related events during the summer and fall. These events had impacts on both the supply and demand in the market.

- *Impacts of COVID-19*: Load reductions in the spring because of COVID-19, combined with historically low gas prices, contributed to the lowest real-time energy prices since the MISO's inception, averaging $18 per MWh. Supply was also affected as COVID measures impacted several planned generator outages that were delayed or moved during the spring months, and other outages were extended through the summer. According to MISO, the schedule for more than 20 GW of planned outages in the spring was modified or the outages cancelled, with up to 3 GW of those outages rescheduled into the fall.

- *July Heat Week in the Midwest*: In the first full week of July, MISO experienced hot temperatures and high humidity in the Midwest region. The tightest conditions during the week occurred on July 6 and MISO experienced emergencies on July 7 and 9:

  - *July 7 Maximum Generation Event in the Midwest*: MISO declared a Maximum Generation Event in the Midwest Region, which led to a commitment of all available resources. Afternoon storms flattened the load across the peak and the emergency conditions did not materialize so the emergency resources did not set prices. More than 15 GW of capacity was unavailable during the event due to outages and derates.

  - *July 9 Transmission System Emergency*: MISO declared a Transmission System Emergency from 4:10 p.m. to 7 p.m. to help manage two parallel constraints that were impacted by outages. This was intended to allow access to the emergency ranges of online resources. IESO was in a capacity emergency and had reduced its exports to Michigan by 700 MW. A key unit that would have provided significant congestion relief was unavailable because of a COVID-19 outbreak at the plant.

- *August 27 Hurricane Laura in the South*: On August 27, Hurricane Laura made landfall as a category 4 hurricane near Lake Charles, LA, resulting in substantial damage to the transmission system. A large swath of dead buses (buses disconnected from the grid) in the path of the hurricane effectively isolated the MISO area in eastern Texas, designated as the Hurricane Laura Load Pocket (HLLP). More than 6,000 MW of generation was forced out of service in and near the HLLP and transfer capability into the area was sharply reduced, causing MISO to shed more than 500 MW of firm load in the HLLP. MISO declared that all affected nodes would be priced at the Value of Lost Load (VOLL) in real time only on August 27, although load was directed to stay off for days after the event. Prices in the week after the event were inefficiently low until MISO created a reserve zone for the HLLP to allow prices to reflect the tightness in the area.

- *October 10 Hurricane Delta in the South*: On October 10, Hurricane Delta made landfall just east of the area impacted by Hurricane Laura, although the impacted area in the path of the hurricane was less extensive. Because MISO had established a reserve zone for the HLLP, pricing in the load pocket reflected tight conditions in the area. On October 10 and 11, there was a $45 day-ahead premium to procure reserves in the newly established reserve zone for the HLLP. In response to prices, some resources returned from outage early and a non-capacity resource switched from ERCOT to MISO.

Emergency events have become more frequent in recent years, and MISO has recognized that contributing factors such as weather-related anomalies, wind uncertainty, and other unforeseen factors contribute to growing uncertainty in load forecasting and reliability needs. Based on our review of these events, which is provided in Section II.E, we find that MISO's emergency declarations and actions are often inconsistent from event to event. Hence, we recommend MISO strengthen its operating procedures to clarify the criteria and improve the operator logging of regional emergency declarations and actions.

## 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. Given the timing of the expected increases and decreases in the output from solar resources in MISO, a large quantity of these resources would likely lead to significant changes in the system's ramping needs.

- *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.[2]
- *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.

Based on our evaluation of these issues, we find that no fundamental changes in MISO's markets are needed in response to the unprecedented changes in its generation portfolio. The vast majority of issues that will arise as the system changes over the next decade can be addressed with the following key improvements to the MISO markets that we discuss in this Report:

- Implementation of an uncertainty product to reflect MISO's current and future need to commit resources for sufficient supply availability in real time to manage uncertainty.
- Improvement of its shortage pricing to compensate the resources that are available and flexible 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.
- Reform of capacity accreditation to allow resources' capacity credit under Module E to match their reliability value.

## Long-Term Economic Signals and Resource Adequacy

### *Capacity Levels and Summer Capacity Margins*

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. The accelerating retirements of baseload resources are being replaced with intermittent renewable resources. In 2020, 2 GW of resources retired in MISO, including a mid-sized nuclear unit. While very few coal resources retired in 2020, we expect the trend of coal resource retirements to continue because of sustained low natural gas prices and the weak economic signals provided by MISO's current capacity market.

In 2020, more than 8 GW of new capacity entered MISO. A 1,000 MW natural gas-fired combined-cycle came online in a key constrained area of MISO South. More than 5 GW (nameplate) of wind resources were added in 2020, but wind resources provide much less reliability value than conventional resources. Additional investment in wind resources is likely

2 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).

to occur in the coming years, particularly since most Multi-Value Projects (MVP) that expand transmission from favorable wind areas are underway or completed, the cost of which total more than an estimated $6.5 billion.

Based on the capacity market design concerns we discuss in this report, we expect the surplus installed capacity in MISO to continue to fall. In the near term, 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. In the long term, however, we are very concerned about MISO's resource adequacy. As we explain in this report, the fundamental problem is the relatively low net revenues generated in MISO's markets.

#### *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 2020. We find:

- Compared to 2019, net revenues fell in most regions. Net revenues increased significantly in Texas as a result of shortage pricing in that region on August 27 after MISO instructed firm load shed;
- Net revenues continued to be substantially less than necessary for new investment to be profitable in any MISO area (i.e., is less than the annual Cost of New Entry, or "CONE"). The lone exception was in Michigan where capacity revenues for the second half of the year were equal to CONE;
- Net revenues for a number of the existing resources are less than necessary to cover their Going-Forward Costs (GFCs), providing economic incentives to retire these units; and
- Low natural gas prices have led to low energy prices, which have disproportionately affected the net revenues of non-gas-fired resources, most notably coal and nuclear units.

The low level of net revenues generated by the MISO markets is problematic for both existing resources and potential new resources. Improving price signals and associated net revenues will require improvements in MISO shortage pricing and its capacity market design. Capacity market design issues have contributed to understated price signals, which will become an increasing concern as the capacity surplus falls.

#### *Evaluation of PRA Results*

MISO administers a Planning Resource Auction (PRA) to allow its participants to buy and sell capacity in various zones in MISO and satisfy the capacity requirements established in Module E of the MISO Tariff. The auction includes MISO-wide requirements, local clearing requirements in ten zones, and models a transfer constraint between MISO South and MISO Midwest regions.

Beginning in the 2019–2020 PRA, MISO established external resource zones to prevent external resources from satisfying the local requirements of internal zones.

The capacity auction design issues described below, along with modest changes in supply and demand, have resulted in extremely low prices in most areas over the past two years:

- In the 2020-2021 PRA, Zone 7 cleared at CONE because it was short of resources, while all other zones cleared from $4.75 to $6.88 per MW-day.
- In the 2021–2022 PRA, the Midwest (including Michigan) cleared at $5.00 per MW-day while the South cleared at $0.01 per MW-day.

In the 2021-2022 PRA, prices cleared at inefficiently low levels. This is a concern because capacity revenues should provide existing resources that are needed with sufficient revenues to cover the cost of remaining in operation and performing maintenance. In this report, we include an analysis of MISO's capacity at risk, and find that typical coal and nuclear resources exhibit revenue shortfalls under the current capacity construct. But for supplemental revenues provided outside of the market, these resources would be uneconomic to continue operating.

***PRA Market Design***

The low clearing prices throughout most of the footprint in the recent auctions are a result of several capacity market design issues that undermine the efficiency of the PRA. The most significant design flaw relates to how the demand for capacity is represented. Demand in the PRA is modeled as a single requirement (and single zonal requirements), and a deficiency price prevails if the market is short (as occurred in Zone 7 in the 2020-2021 auction). This establishes a "vertical demand curve" for capacity, which implicitly values incremental capacity above the minimum requirement at zero. This is inconsistent with its true reliability value and results in inefficient capacity market outcomes.

To address this issue, we continue to recommend that MISO adopt a sloped demand curve to reflect the reliability value of the surplus resources in excess of MISO's minimum clearing requirement. This report shows that such a change would benefit MISO's regulated participants by *lowering* their net costs of satisfying the planning requirements by $120 million by allowing them to sell their surplus capacity at prices that reflect its value. Nonetheless, because most of their planning needs are self-supplied, the effects on the regulated participants of improving the demand curve is smaller, adjusting for their size, than the effects on competitive loads and suppliers who rely on economic market signals to guide their long-term investment and retirement decisions. Competitive generation would see their revenues rise by more than $288 million and competitive retail loads' costs would rise by almost $450 million because they would have to pay efficient prices to purchase capacity in MISO. We note that bilateral contracts can change how each participant is affected by changes in the PRA prices. In sum, it would be extremely valuable to improve the PRA design to allow it to establish efficient prices.

In addition to addressing the fundamental design issue related to the modeling of the demand in the PRA, we have 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:

- Reforming resource accreditation to better reflect the reliability value of resources by recognizing resources' true availability under the tightest market conditions.
- Disqualifying energy efficiency from selling capacity in the PRA.
- Procuring capacity to serve all firm load, including behind-the-meter firm process load.
- Developing ELCC methods to estimate the marginal capacity value of all intermittent, energy storage, and other resources not feasible to accredit based on availability.

Other improvements we recommend that do not specifically involve the supply or demand for capacity in the PRA include: i) transitioning to a seasonal capacity market, and ii) improving the modeling of transmission constraints in the PRA. A number of these recommendations are likely to be addressed through MISO's RAN initiative discussed in Section XI.D of the report.

## Day-Ahead Market Performance and Virtual Trading

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 2020:

- The difference between day-ahead and real-time prices was 0.8 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 rose 5.4 percent in 2020 to average nearly 18 GW per hour. Our evaluation of virtual transactions revealed:

- Approximately 87 percent 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.

## Real-Time Market Performance and Uplift

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. Although MISO's shortage pricing methodology is reasonable, we have two concerns that undermine the efficiency of MISO's shortage pricing:

- MISO's operating reserve demand curve (ORDC) is not efficient because it does not reflect the expected Value of Lost Load (VOLL) — we recommend MISO introduce an efficient ORDC as described in Section III.B; and
- The shortage pricing is undermined by allowing offline resources to set prices in the ELMP model. MISO plans to limit offline ELMP participation to resources recommended for commitment by the Look-Ahead Commitment model. This change addresses our recommendation and will improve ex-post pricing.

Improving MISO's shortage pricing is essential because it will align shortage pricing with the marginal reliability value of the foregone reserves.[3] Adopting an ORDC that is similar to the curve we estimate and discuss in this report will result in more efficient economic signals that govern both short-term and long-term decisions by MISO participants.

3 Based on recent studies and a model developed by Lawrence Berkeley National Laboratory, we recommend MISO establish its ORDC based on a VOLL of more than $20,000 per MWh. The slope of the ORDC should be determined by how the LOLE changes as the level of operating reserves falls. The LOLE depends on the countless combinations of random contingencies and conditions that could occur when MISO is short of reserves. Using a Monte Carlo Model, we estimate a reasonable slope for the ORDC.

In addition to MISO's shortage pricing, its ELMP pricing model plays a key role in achieving efficient price formation. ELMP's greatest value is its capability to allow online peaking resources and emergency supply to set prices when they are economic for satisfying the system demands. Our evaluation of the performance of the online pricing in the current ELMP model, however, shows that it has only been partially effective.[4]

- ELMP raised real-time prices by an average of $0.70 per MWh in 2020, more than double the average impact in 2019.
- These price effects increased in part because MISO began allowing fast-start resources committed in the day-ahead market to set prices in November 2019.
- We also propose changes to the ramp assumptions used by ELMP, which we estimate would have increased real-time prices by $0.89 per MWh.

In high-load hours when reliance on peaking units is relatively high, these price effects are far greater, which provides much better incentives to schedule imports and exports efficiently and facilitates efficient generator commitments in the day-ahead market. Hence, improving the performance of ELMP should remain a high priority.

The ELMP model also allows offline fast-start resource to set prices during reserve or transmission shortages (i.e., offline pricing). Offline pricing continues to distort outcomes by preventing the markets from pricing shortages that result from unexpected changes in conditions. When wind output drops unexpectedly, a large unit goes out of service, an export is curtailed, or many other unforeseen things occur, transitory shortages can occur. Allowing offline units to set prices as if they were committed and dispatched is essentially setting prices as if the MISO operators have perfect foresight. This is not true in the real world and pricing these transitory shortages is critical because it compensates the flexible resources that can respond to these shortages and allows MISO to maintain system reliability. In response to this concern and our long-standing recommendation, MISO plans to limit offline ELMP participation to resources recommended to commit in the Look-Ahead Commitment model. This should address our concern by helping restrict ELMP participation to economic and feasible offline resources.

#### *Managing the Flows on the RDT and Regional Reserves*

Since the integration of the South, MISO's intra-regional transfers have been constrained to adhere to contractual limits. MISO has taken two actions to prevent exceeding these limits: implementing a post-contingent constraint to hold headroom on the RDT and actively managing the RDT limit to avoid unmodeled exceedances. Additionally, 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

4 This evaluation is described in Section V.B.

recommended that MISO introduce a 30-minute reserve product for each region. FERC has approved MISO's proposed 30-minute "Short-Term Reserve" and it is scheduled to be implemented in December 2021.

Finally, 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 allow the Joint Parties to sell operating reserves with the transmission capacity on the RDT (above the RDT limit). This would efficiently compensate the Joint Parties and lower MISO's costs of maintaining subregional reserves.

#### *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 165 MW in hours when generators are generally ramping up and more than 365 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.

In response to previous recommendations, MISO implemented improvements to its uninstructed deviation thresholds and price volatility make-whole payment formulas in May 2019 that have improved the performance of MISO's generators substantially. Generator dragging fell roughly 10 percent in 2019 from the prior year. Additionally, 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.

#### *Wind Generation and Forecasting*

Installed wind capacity now exceeds 26 GW as 5.2 GW entered in 2020. Wind output also increased by 25 percent to average 8 GW per hour, accounting for 12 percent of all generation output in 2020. MISO set several all-time wind records in 2020, peaking for the year on December 23 at 20.2 GW. These increasing trends in wind output are likely to continue for the next few years as investment remains strong.

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.

#### *Uplift Costs*

RSG payments are made in both the day-ahead and real-time markets to ensure a supplier's offered costs (including commitment costs) are recovered when a unit is dispatched.

- Nominal real-time RSG payments fell 48 percent to roughly $39 million in 2020.
- Day-ahead RSG rose 71 percent to $57 million. This increase was largely driven by conditions that arose following Hurricane Laura in the South in August.

In September, very high day-ahead RSG was incurred as units with high risk-related costs committed in East Texas in the newly-formed Hurricane Laura Load Pocket received over $30 million in RSG payments. These units' offers reflected a significant risk of outage. This risk manifested when two units tripped after a few days online.

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 requirements, as well as VLR requirements that result in substantial day-ahead RSG costs. FERC approved MISO's proposed STR product and implementation is scheduled for December 2021. We are currently working with MISO to develop appropriate demand curves to price shortages of short-term reserves consistent with sound economic principles.

### 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 market transactions are settled through the day-ahead market, most congestion costs are collected in this market.

### *Congestion Costs in 2020*

The value of real-time congestion rose 26 percent in 2020 to almost $1.2 billion. Congestion in the South and Central Regions fell, but congestion in the North Region more than doubled as wind output increased substantially in 2020. More than half of the real-time congestion was related to wind. Wind output was particularly high in the fall when wind resources set the price in 85 percent of constrained market intervals.

Not all of the $1.2 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 increased to $660 million in 2020, up 24 percent from last year. 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 2020, FTR obligations exceeded congestion revenues by $74.6 million—a shortfall of 4.1 percent before auction residual collections. This is not good because underfunding FTRs degrades the value of the FTRs. Ultimately, this harms transmission customers when they receive reduced revenues from the sale of the FTRs.

### *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, including the following three issues.

*Outage Coordination.* Transmission and generation outages often occur simultaneously and affect the same constraint. In 2020, multiple simultaneous generation outages contributed to more than $225 million in real-time congestion costs—just over 20 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 uses lower fixed ratings, which reduces MISO's utilization of its transmission network. We estimate MISO could have saved $113 million in congestion costs in 2020 by using temperature-adjusted and emergency ratings. In late 2020, FERC issued a proposed rule that would make this a requirement. This supports our continued efforts over the past five years with MISO, transmission owners, and the States to encourage the provision and use these ratings. We have also recommended that MISO improve its systems and processes to allow TOs to provide such ratings in a more timely manner.

*Reduce the GSF Cutoff for Constraints with Limited Relief*. MISO employs a GSF cutoff of 1.5 percent so that low-impact generators will not be re-dispatched to manage congestion. This reduces the solution time of its market software. Unfortunately, this excludes valuable congestion relief on some constraints—generally low-voltage and M2M constraints. This substantially increases congestion costs, can reduce reliability, and lead to FTR shortfalls. Our analysis shows $53 million of incremental economic relief would be available if the GSF cutoff were reduced to 0.5 percent. We have tested the effects of lowering the GSF cutoff to 0.5 percent on the solution times of MISO's market models and found that it would not substantially extend the solution times. Further, both SPP and PJM employ a zero cutoff on market-to-market constraints. MISO's relatively high cutoff results in more costly M2M settlements for MISO. For all these reasons, we recommend that MISO reduce the GSF cutoff to at least 0.5 percent.

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 these issues.

### *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 increased 37 percent in 2020 to $530 million, which is more than 45 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 shows that for the most frequently binding M2M constraints, the 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 could deliver substantial additional cost savings.

*Improve the relief request software*: The amount and timing of relief requested by the MRTO from the NMRTO is essential because suboptimal relief quantities can prevent the NMRTO from providing all available economic relief or can cause a constraint to oscillate from binding to unbinding in alternating intervals. In our prior study of the coordination between MISO and SPP from June 2018 through May 2019, we estimated that the real-time congestion on MISO and SPP M2M constraints would have fallen by $41 million if the two RTOs had requested optimal quantities of relief from each other. Because the relief request is calculated in the same manner with PJM, comparable benefits are likely available with PJM as well. Hence, we recommend that MISO work with SPP and PJM to improve the relief request software.

*Replace the 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 five percent or greater shift factor on the constraint (i.e., 20 MW of output changes the flows by 1 MW). We have found that 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. We also recommend that raise-help wind resources not be included in this test (or in the five-percent test). Wind resources cannot generally increase output to provide relief because they are usually producing as much output as possible.

*Lower the GSF cutoff.* As discussed above, MISO's GSF cutoff discussed above is impairing MISO's ability to provide relief on externals constraints, which is resulting in much more costly settlements with PJM and SPP. We recommend that MISO lower the cutoff for M2M constraints to allow more of its generators to be used to manage the congestion on these constraints.

*Improve the 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 to determine whether they should be defined as M2M constraints. However, MISO was less reliable in requesting tests in a timely manner in 2020. Given that much of this process continues to be implemented manually, there are still significant opportunities to employ greater automation to improve the timeliness with which constraints are tested and how quickly coordination is activated after M2M constraints bind.

## External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2020, importing an average of 7.2 GW per hour in real time, up from 6.2 GW in 2019. MISO's imports from PJM in 2020 averaged more than 3.7 GW per hour, up 54 percent from 2019. 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 the power sources and sinks throughout each RTO's footprint since this is what happens in reality. However, in response to a concern we first raised in 2012 regarding redundant pricing of congestion at the PJM-MISO interface, MISO agreed to adopt a new "common interface" definition for the PJM interface in June 2017. This new interface definition consists of 10 generator locations near the PJM seam, with five points in MISO's market and five in PJM. Our evaluation of the performance of this common interface reveals that it 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 interface pricing approach we recommend below for the SPP interface.

At the SPP interface, we have verified that redundant congestion pricing is still occurring based on their overlapping interface definitions. Given the poor performance of the common interface adopted with PJM, this approach should not be considered at the SPP interface. We encourage MISO and SPP to adopt an efficient interface pricing method at the SPP interface and its other interfaces (except the PJM interface) 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. Adopting accurate assumptions regarding where imports source and exports sink when calculating interface congestion prices is also important. MISO's assumptions for most interfaces are good, including for the SPP interface. The common interface adopted with PJM is the notable outlier.

*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.

Up until early 2019, there had been almost no participation in CTS. We have previously shown that high transmission charges and persistent forecast errors have likely deterred traders from using CTS. In 2020, the average quantity of CTS transactions offered and cleared fell to 140 MW and 60 MW, respectively. Most of these transactions were in the import direction, submitted by a participant with long-term firm transmission rights that can avoid the charges that deter other traders. The CTS process implemented between the New York ISO and ISO New England is more widely used because they apply no charges to these transactions.

However, forecasts are a substantial problem undermining all of the current CTS processes. It is unlikely that PJM and MISO can substantially improve their forecasts given the timing of the information used. To improve the CTS process and maximize its savings, 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 5 minutes 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 VIII.B. of this report shows that it would have raised the production cost savings of the CTS process with PJM from $270,000 in 2020 under the current approach to more than $12 million under the 5-minute adjustment approach.

## Demand Response and Energy Efficiency

Demand response is an important contributor to MISO's resource adequacy and provides a number of other benefits to the market. With the resolution of issues related to FERC Order 745 by the U.S. Supreme Court in early 2016, MISO continues to seek to expand its DR capability. This includes efforts to allow for Batch Load DR and Price Responsive Demand. Currently, MISO has more than 13.5 GW of DR resources, which includes 4.3 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. More than 85 percent of MISO's DR resources are capacity resources or LMRs that can only be accessed after MISO has declared an emergency.

MISO has recently made several changes to improve accessibility and real-time information on the availability of LMRs. In early 2019, MISO modified its Tariff to: a) allow MISO to schedule LMRs in anticipation of an emergency event to access longer-lead resources, b) require additional testing for LMRs, and c) require LMRs to register availability consistent with their seasonal capability. FERC has approved Tariff changes that reduce the allowable lead time for qualifying LMRs to 6 hours and accredits resources based on the availability throughout the planning year. These changes will be phased-in across multiple planning years, starting in 2022–2023, to allow participants to modify existing contracts and replace affected capacity. Although we still have concerns that LMRs are not as accessible and do not provide comparable reliability to generating resources, these changes are clear improvements.

In addition to active demand response, MISO also allows energy efficiency (EE) to qualify to provide capacity. The quantity of EE participating in the PRA has been growing rapidly and is playing a more pivotal role in satisfying MISO's resource adequacy needs. Given the rapid increase in EE 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 payments equal to the capacity price for assumed load reductions provides redundant compensation to the retail electricity bill savings customers receive and is, therefore, not economically efficient or necessary;
- 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 second concern regarding 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 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 resource 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 Tariff.

These findings are unfortunate because MISO's customers paid more than $17 million to these resources 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 consider whether to continue to allow EE measures to be sold in MISO's capacity auction.

## Table of Recommendations

Although the markets performed competitively in 2020, we make 28 recommendations in this report intended to further improve their performance. Four are new this year, while 24 were recommended previously. It is not unexpected that recommendations carry over from prior years since many of them require software changes that can take years to implement. MISO addressed four of our recommendations since our last report, as discussed in Section XI.E.

The table 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 indicate whether each would provide high benefits and whether it can be achieved in the near term.

| SOM Number | Recommendations | High Benefit | Near Term |
|---|---|---|---|
| **Energy Pricing and Transmission Congestion** | | | |
| **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. | ✓ | |
| **2018-2** | Lower GSF cutoff for constraints with limited relief. | ✓ | ✓ |
| **2016-1** | Improve shortage pricing by adopting an improved Operating Reserve Demand Curve reflecting the expected value of lost load. | ✓ | ✓ |
| **2016-3** | Enhance authority to coordinate transmission and generation planned outages. | | |
| **2015-2** | Expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities. | ✓ | ✓ |
| **2012-5** | Introduce a virtual spread product. | | |
| **2014-3** | Improve external congestion related to TLRs by developing a JOA with TVA and IESO. | | |
| **2012-3** | Remove external congestion from interface prices. | | ✓ |
| **Operating Reserves and Guarantee Payments** | | | |
| **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 the reserves are deployed. | | |
| **Dispatch Efficiency and Real-Time Market Operations** | | | |
| **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. | ✓ | ✓ |

| SOM Number | Recommendations | High Benefit | Near Term |
|---|---|---|---|
| **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. | | ✓ |
| **2018-5** | Improve capacity accreditation by basing it on resource availability during tight supply conditions. | ✓ | |
| **2018-6** | Modify the supply and demand inputs for capacity by: a) accounting for behind-the-meter process load, and b) improving planning assumptions. | | ✓ |
| **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. | | |
| **2014-5** | Transition to seasonal capacity market procurements. | | |
| **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 2020 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 2020 include:

- In January, FERC approved MISO's proposed Short-Term Reserves, which are scheduled to be implemented in December 2021.

- MISO implemented several changes that improved the qualifying of resources to participate in the Planning Resource Auction (PRA):
  - Resources that plan to be on outage for 90 of the first 120 days of the Planning Year cannot qualify to participate in the PRA;
  - LMRs' qualification requirements were improved so they are based on their registered lead time and the number of available calls throughout the year;
  - Rules improved to ensure that the capacity offered by both conventional and intermittent resources are fully deliverable;
- In February and March, FERC approved a number of improvements to MISO's market power mitigation measures in Module D of its Tariff.[5]
- In March, FERC accepted Tariff changes to eliminate the relaxation of market-to-market constraints, and changes to MISO's credit policies to reduce default risks.

In addition, MISO filed proposed changes in a number of other key areas:

- In December, MISO filed Tariff revisions to eliminate make-whole payments for resources deployed for spinning reserves in order to incent market participants to incorporate these expected deployment costs into their spinning reserve offers.
- MISO also filed significant changes to the Emergency Pricing Construct in December, which include raising the emergency offer floor prices, expanding the resources that can set prices in ELMP during emergencies, and making other improvements to the pricing parameters.
- MISO also filed proposed Tariff changes requiring LMR availability to be updated continually and implementing penalties for failing to follow scheduling instructions.

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 recommend essential changes to MISO's shortage pricing, capacity 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 XI of the report, which describes the status of each existing recommendation and identifies recommendations that have been addressed by MISO over the past year.

5 FERC rejected Tariff changes that would have applied physical withholding mitigation measures to non-capacity resources in the day-ahead market.

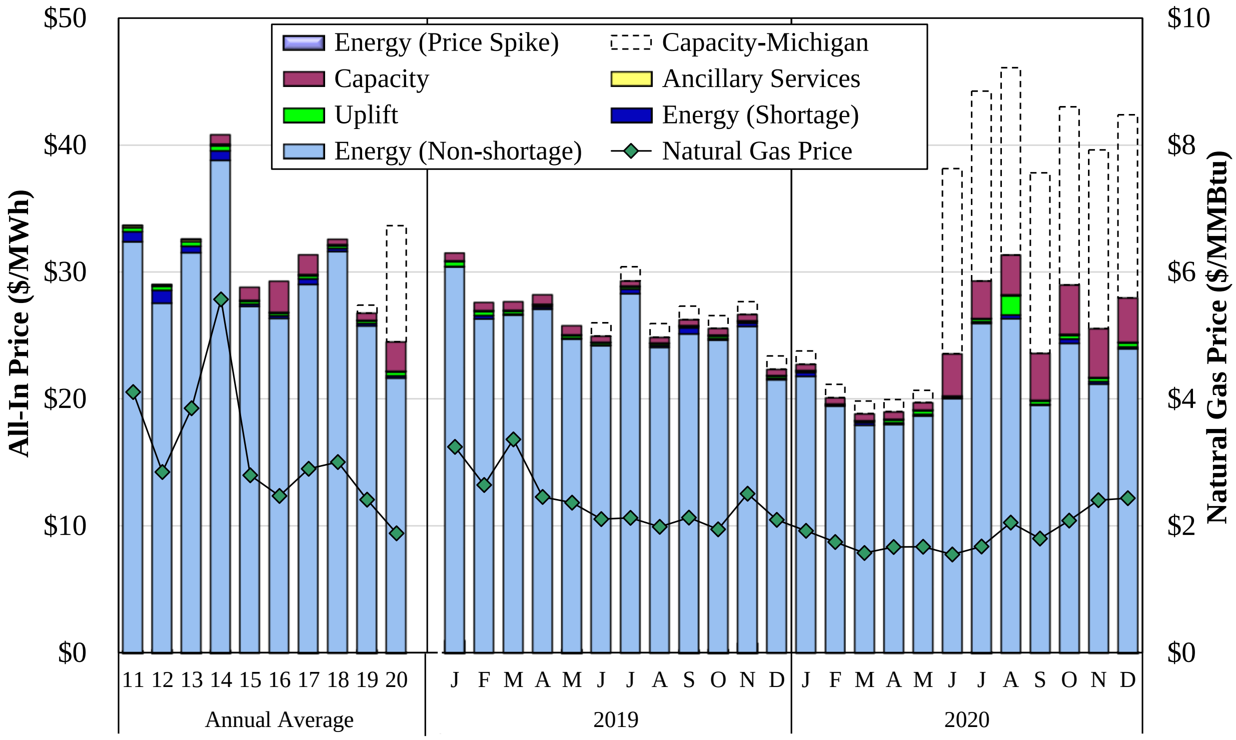
# II. Price and Load Trends

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 2020

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. We separately show the portion of the all-in price that is associated with shortage pricing, as well 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**
2019–2020

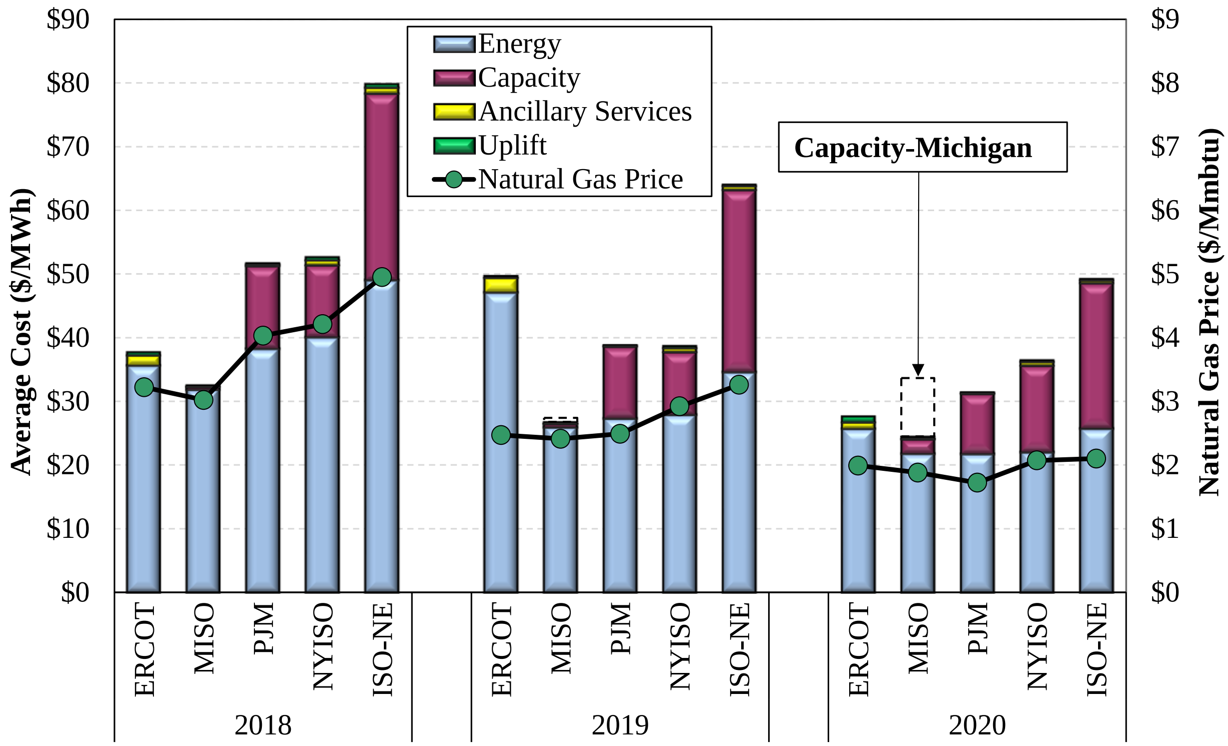


The all-in price fell 8 percent in 2020 to an average of $24.50 per MWh because:

- Energy prices declined by 16 percent to record lows as natural gas prices fell 22 percent and average load fell 4 percent partly because of the effects of the COVID-19 pandemic.
- The shortage pricing contributions remained low at less than one percent.
- The ancillary services component contributed only $0.07 per MWh.
- The 2020–2021 capacity auction cleared between $5 and $7 per MW-day throughout MISO, except in Zone 7 (Michigan), which cleared at the Cost of New Energy of $258 per MW-day because Zone 7 was deficient.
- The uplift component of the all-in price increased 13 cents to $0.31 per MWh.[6]

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 cost, 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**
2018–2020



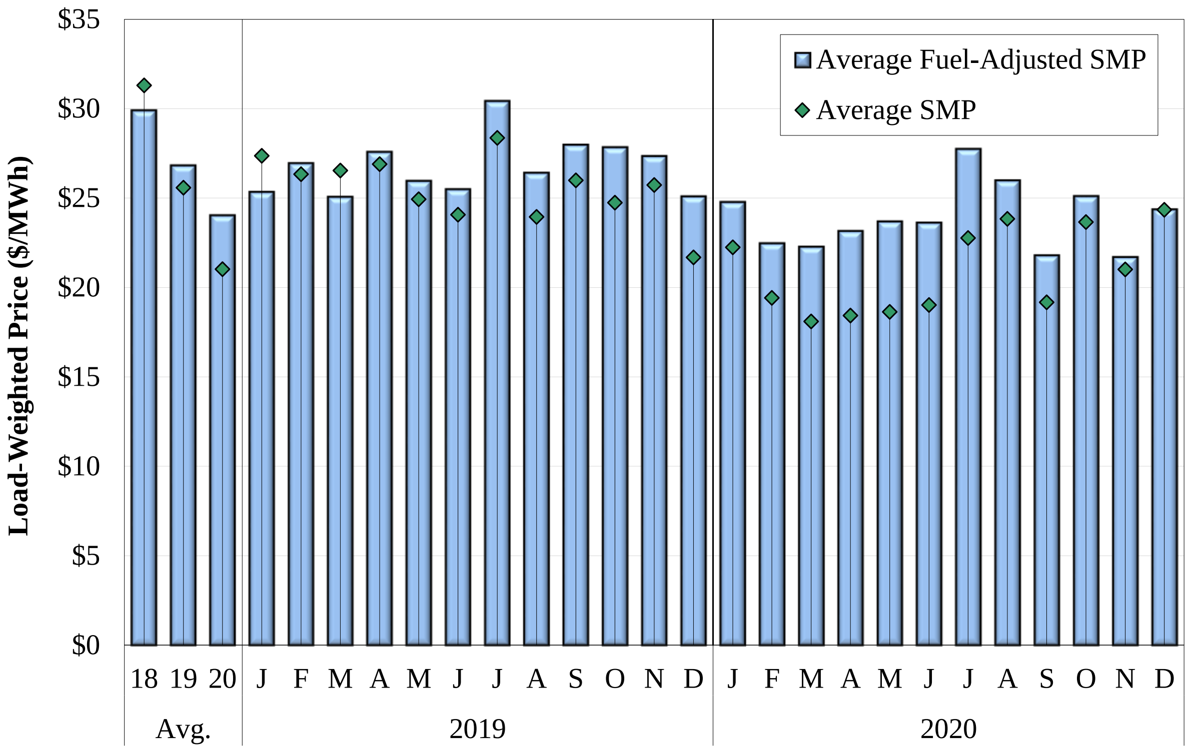

6 Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs, and Price Volatility Make-Whole Payments (PVMWPs). PVMWPs are made to ensure resources are not harmed when following MISO's dispatch instructions. Balancing Congestion payments in August 2020 resulting from Hurricane Laura also materially contributed to system-wide uplift costs.

Each of these 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 availability, and differences in the transmission capability of the network.

In Figure 2, MISO exhibits 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.[7]

**Figure 3: Fuel-Adjusted System Marginal Price**
2019–2020




While the nominal SMP in 2020 fell by 18 percent relative to 2019, the fuel-price adjusted SMP fell by 11 percent. This decline can be attributed in part to a 4 percent decline in load resulting from COVID-19, as well as continued growth in wind output. Although they rarely set prices outside of local areas, wind units shift the supply curve and cause prices to be set at lower levels.

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

## B. Fuel Prices and Energy Production

The substantial changes in fuel prices during 2020 altered the generation output in MISO. Historically low natural gas prices increased MISO's natural gas-fired output and decreased the output from coal-fired resources. Additionally, the resource mix continued to evolve in 2020, as 2 GW of retirements and suspensions were replaced by additions of 5.2 GW of wind resources in the Midwest, and almost 2 GW of gas resources in the Midwest and South. Table 1 below summarizes the share of capacity, energy output, and how frequently different types of resources were marginal in setting system-wide energy prices and local energy prices in 2019 and 2020.

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

| | Unforced Capacity | | | | Energy Output | | Price Setting | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total (MW) | | Share (%) | | Share (%) | | SMP (%) | | LMP (%) | |
| | 2019 | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 | 2020 |
| **Nuclear** | 12,107 | 11,638 | 9% | 9% | 17% | 17% | 0% | 0% | 0% | 0% |
| **Coal** | 46,864 | 46,030 | 37% | 36% | 39% | 34% | 47% | 40% | 81% | 87% |
| **Natural Gas** | 56,673 | 58,226 | 44% | 45% | 31% | 34% | 51% | 57% | 89% | 98% |
| **Oil** | 1,568 | 1,578 | 1% | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Hydro** | 4,034 | 3,729 | 3% | 3% | 2% | 2% | 1% | 1% | 2% | 3% |
| **Wind** | 3,660 | 4,470 | 3% | 3% | 9% | 12% | 1% | 1% | 38% | 69% |
| **Other** | 2,703 | 3,061 | 2% | 2% | 1% | 1% | 0% | 0% | 2% | 7% |
| **Total** | **127,608** | **128,732** | | | | | | | | |

*Energy Output Shares.* The lowest marginal cost resources (coal and nuclear) operated at the highest capacity factors. However, falling natural gas prices resulted in the energy shares of coal and natural gas resources to converge. Natural gas resources' share of output grew to 34 percent, but it remained well below its share of capacity (45 percent). Much of this increase was from combined-cycle resources that have displaced higher-cost coal output as gas prices have fallen.

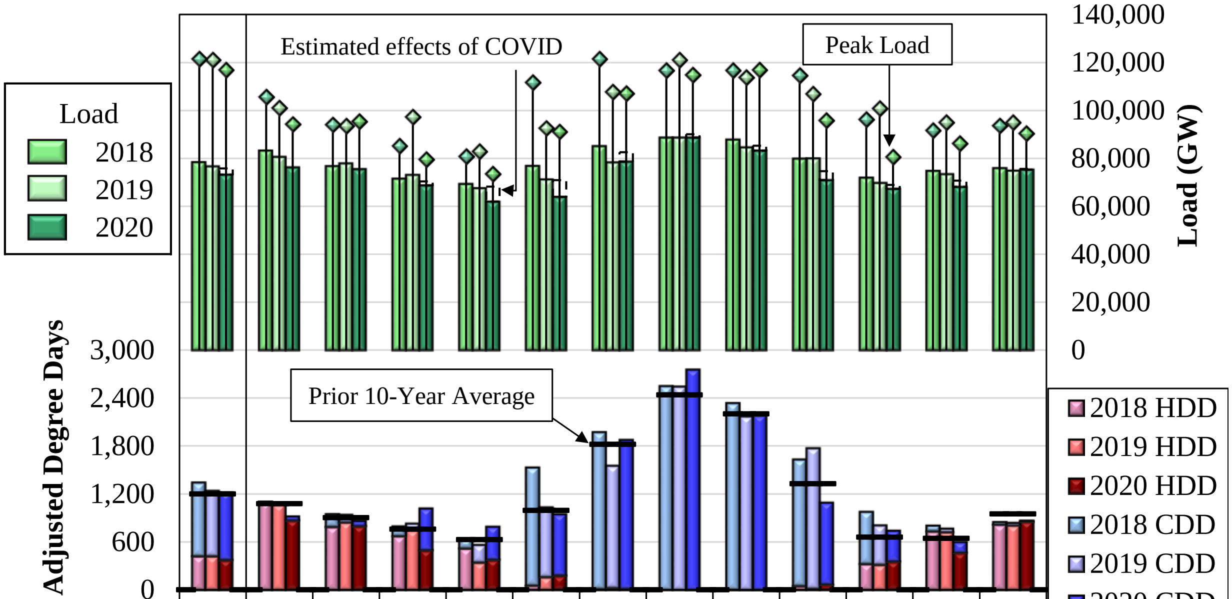
*Price-Setting Shares.* Coal resources set system-wide prices in 40 percent of hours, down from 47 percent of hours in 2019, generally in off-peak hours. Although natural gas-fired units produce one-third of the energy in MISO, they are pivotal in setting energy prices. Gas-fired units set the system-wide price in 57 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. This is why gas-fired resources set local LMPs in 98 percent of intervals and why they are a key driver of energy prices. Multiple types of resources may be marginal at different locations in the same interval because of binding transmission constraints.

*Wind Resources.* The capacity values for the resources in Table 1 are Unforced Capacity, which is lower than installed capacity levels to account for outages and intermittency. This has a large effect on wind units, which are derated by more than 80 percent. Hence, they account for only 3 percent of the capacity but 12 percent of energy output. Wind units often cause congestion on lines exiting their locations, causing them to set local prices more than two thirds of the time.

## C. Load and Weather Patterns

Long-term load trends are driven by economic and demographic changes in the region, but short-term load patterns are generally determined by weather. Figure 4 indicates the influence of weather by showing the heating and cooling needs together with the monthly average load over the past two years. The top panel shows the monthly average load in the bars and the peak monthly load in the diamonds. The bottom panel shows monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) summed across six representative locations in MISO.[8]

**Figure 4: Heating and Cooling Degree Days**
2018–2020




| % Chg 19-20 | Avg | J | F | M | A | M | J | J | A | S | O | N | D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Avg. Load | -4% | -5% | -3% | -6% | -8% | -10% | 1% | 0% | -2% | -11% | -3% | -7% | 1% |
| Degree Days | -1% | -14% | -8% | 23% | 41% | -8% | 21% | 9% | 1% | -38% | -8% | -21% | 3% |

In March, the COVID-19 pandemic led to sweeping shutdowns and lower load throughout 2020. The ghost bars on top of the average load bars indicate the estimated effects of COVID on load. Nonetheless, the average number of degree days was similar to 2020, falling by one percent. June and July were warmer in 2020, while September was warmer and January was cooler in 2019. Some cold and hot weather episodes occurred throughout the year, including:

- MISO declared a Maximum Generation Alert in the South on February 21 as cold temperatures delayed the start of some units and load exceeded the MISO's forecast.
- On June 10, MISO declared a Local Transmission Emergency in Michigan as significant storms in the area caused transmission outages and high loads.

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

- Hotter than usual temperatures in July led to Hot Weather Alerts, Capacity Advisories, and a Maximum Generation Event in the Midwest.
- In mid-October, relatively cold temperatures in the Midwest caused residential and commercial natural gas consumption to triple and increased gas prices in the Midwest.

Average annual load fell four percent, primarily because of the various responses to the COVID-19 pandemic. MISO's annual peak load of 117 GW occurred on August 24. After accounting for voluntary LMR curtailments of 1.7 GW, actual peak load was five percent below the 50/50 forecasted peak of 125 GW from MISO's *2020 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.

The supplemental reserves only contribute to meeting the market-wide operating reserve (i.e., contingency reserves) requirement. Spinning reserves can satisfy the operating reserve requirement, so the spinning reserve price will include a component for the operating reserve shortages. Hence, energy prices include the sum of the shortage values of all ASM products plus the marginal cost of satisfying the energy demands. Likewise, regulation prices will include components associated with spinning reserve and operating reserve shortages.[9]

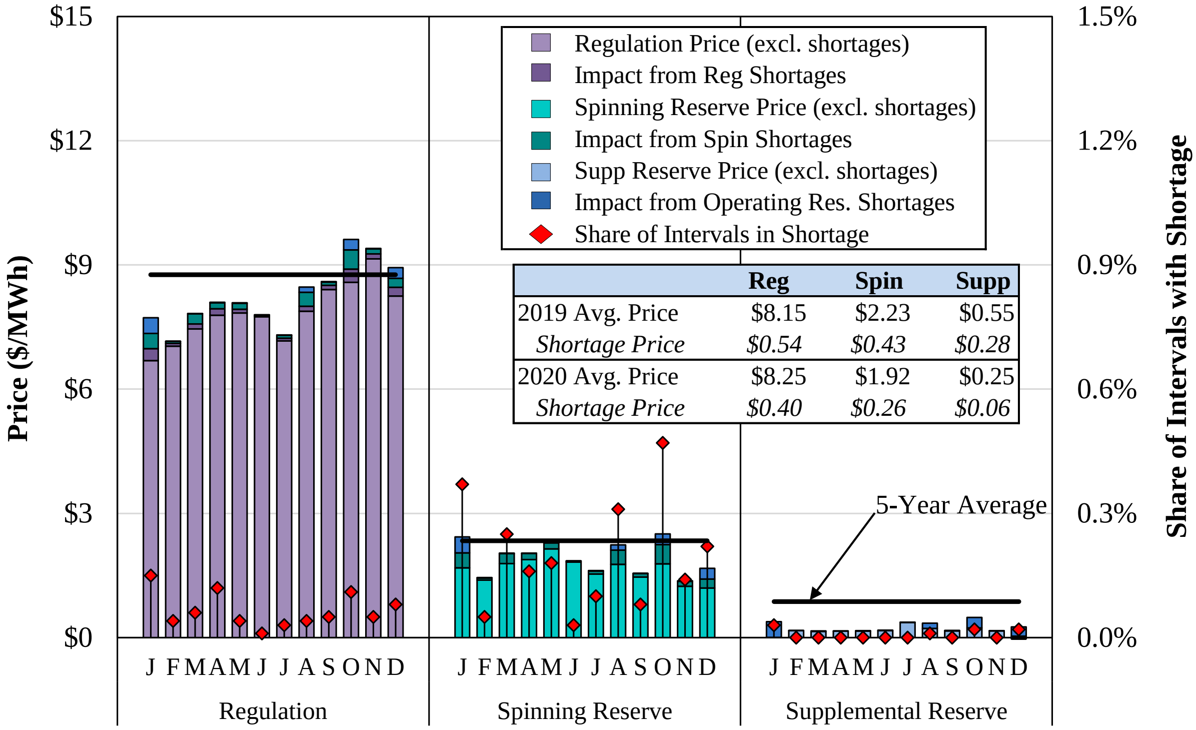
MISO's demand curves specify the value of each of its reserve products. When the market is short of a reserve product, the demand curve for the product will set its market clearing price and affect the prices of higher-valued reserves and energy through the co-optimized market clearing.

### *Ancillary Services Prices in 2020*

For each product, Figure 5 shows monthly average real-time prices, the contribution of shortage pricing to each product's price in 2020, and the share of intervals in shortage. The figure also shows the 5-year nominal average price of the reserve products. Figure 5 shows that average clearing prices declined for spinning and supplemental reserves but rose for regulation. This was primarily because of changes in natural gas prices and variations in wind output. A reduction in opportunity costs resulting from lower natural gas prices contributed to the decrease in the spin prices.

9 The demand curve for regulation, which is indexed to natural gas prices, averaged $110.45 per MWh in 2020, down from $132.49 in 2019. 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**
2020




## E. Significant Events and Market Outcomes

In 2020, the public response to the COVID-19 pandemic impacted MISO beginning in the spring, and MISO experienced multiple significant weather-related events during the summer and fall. As described below, these events had impacts on both the supply and demand in the market. We provide a summary of the events and the impacts on prices and the markets.

### *Impacts of COVID-19*

In the spring, the COVID-19 pandemic resulted in public responses, including stay-at-home measures in several member states. The public response had a significant impact on load during the spring and fall, whereas during the summer months hotter than normal temperatures and the lifting of COVID-related restrictions muted the impacts. Average load in the spring was 7 percent lower than in 2019 because of COVID-19, and during the fall the average impact was a 5 percent reduction in load.[10] Load reductions in the spring because of COVID-19 combined with historically low gas prices contributed to the lowest real-time energy prices since the inception of MISO, averaging $18 per MWh.

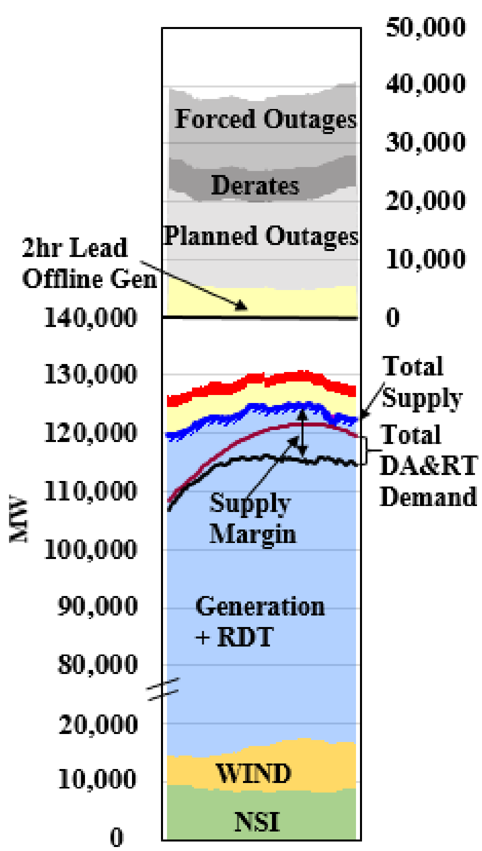
10 MISO estimated the impact of COVID-19 on load by back-casting actual weather in its load forecasting tools.

In addition to the impacts on load, several planned generator outages were delayed or moved during the spring months because of COVID-19 measures, and other outages were extended through the summer. More than 20 GW of planned outages were cancelled or rescheduled during the spring months, and between 2 and 3 GW of those outages occurred in the fall. A critical resource that would have provided a significant amount of congestion relief during a Local Transmission Emergency in Michigan in June and Transmission System Emergency in July was unavailable during both events due to COVID-19 impacts on plant personnel.

### *July Heat Week and Maximum Generation Event in the Midwest*

In the first full week of July, MISO experienced hot temperatures and high humidity in the Midwest region. Temperatures in Michigan were over 90 degrees, compared to historical average high temperatures in the low 70s. On July 1, MISO's Maintenance Operating Margin was indicating that the Midwest would have only a 3 to 4 percent margin on the 6th and 7th, and MISO committed several long-lead resources to ensure that scheduled flows across the RDT would remain at 2,500 MW even after the second-largest contingency. This resulted in an average of 1,700 MW that were unable to be dispatched up (i.e., trapped) on average in the South between 2 p.m. and 4 p.m. between July 1 and 9.

As in prior years, we present a figure that shows each component of the supply and demand so they can be analyzed. The illustration to the left shows each element included in Figure 6 below that we use to illustrate system conditions during the first full week in July.




The total available supply is shown in the figure with a royal blue line and it is comprised of NSI (green area), wind (yellow area), online generation plus RDT capability into the 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). As explained below, the red area above the dark blue represents emergency ranges not utilized.

This 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 (not shown). 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.[11]

The figure also shows supply components that are not available to the real-time market (above the royal blue line). This supply includes offline generators with modest start times (< 2 hours and > 30 minutes), shown by the yellow area, and offline emergency generation (Available Maximum Emergency – AME) shown by the red area. The top panel of the figure shows other unavailable generation, including offline generation with long lead times (> 2 hours) shown in yellow, as well as planned outages, forced outages, and derates (shown in shades of gray).

**Figure 6: MISO Midwest Conditions During Heat Week**
July 6–10, 2020

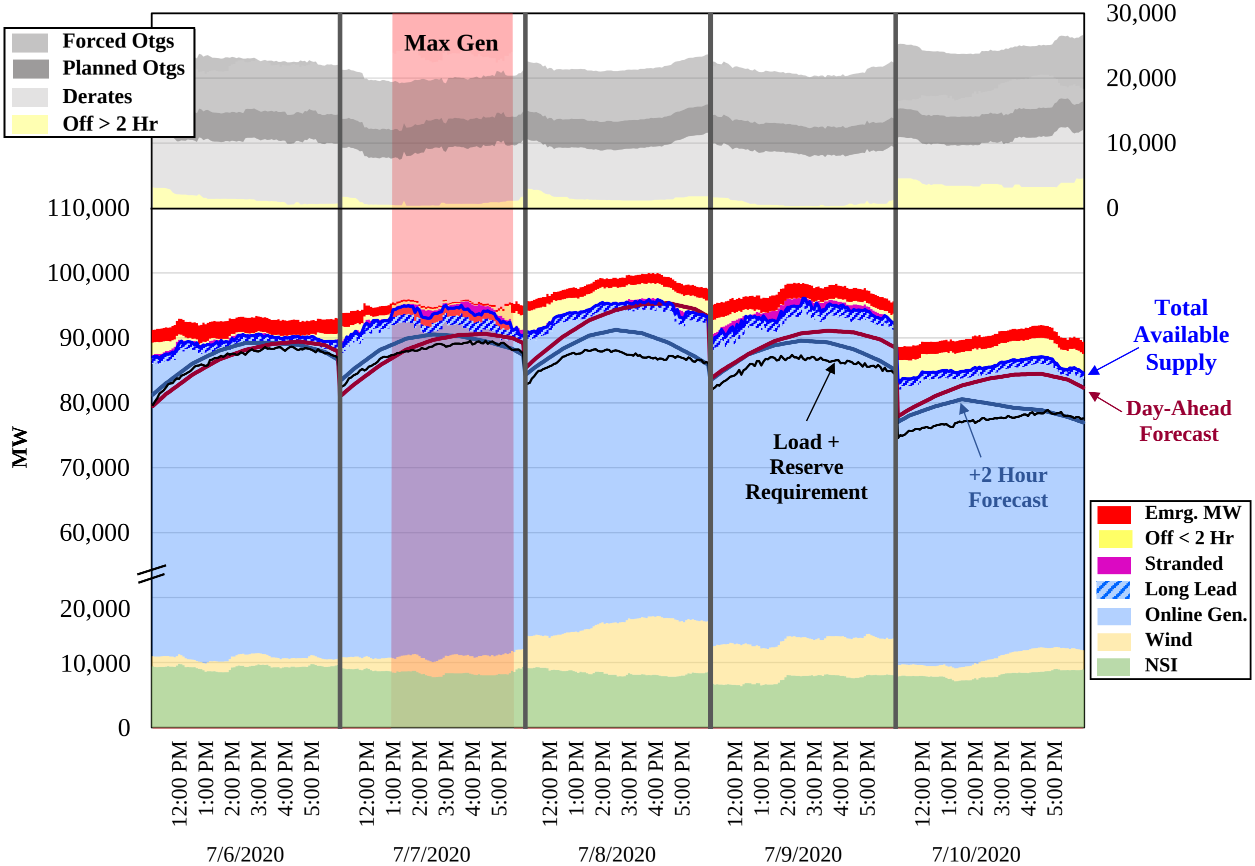


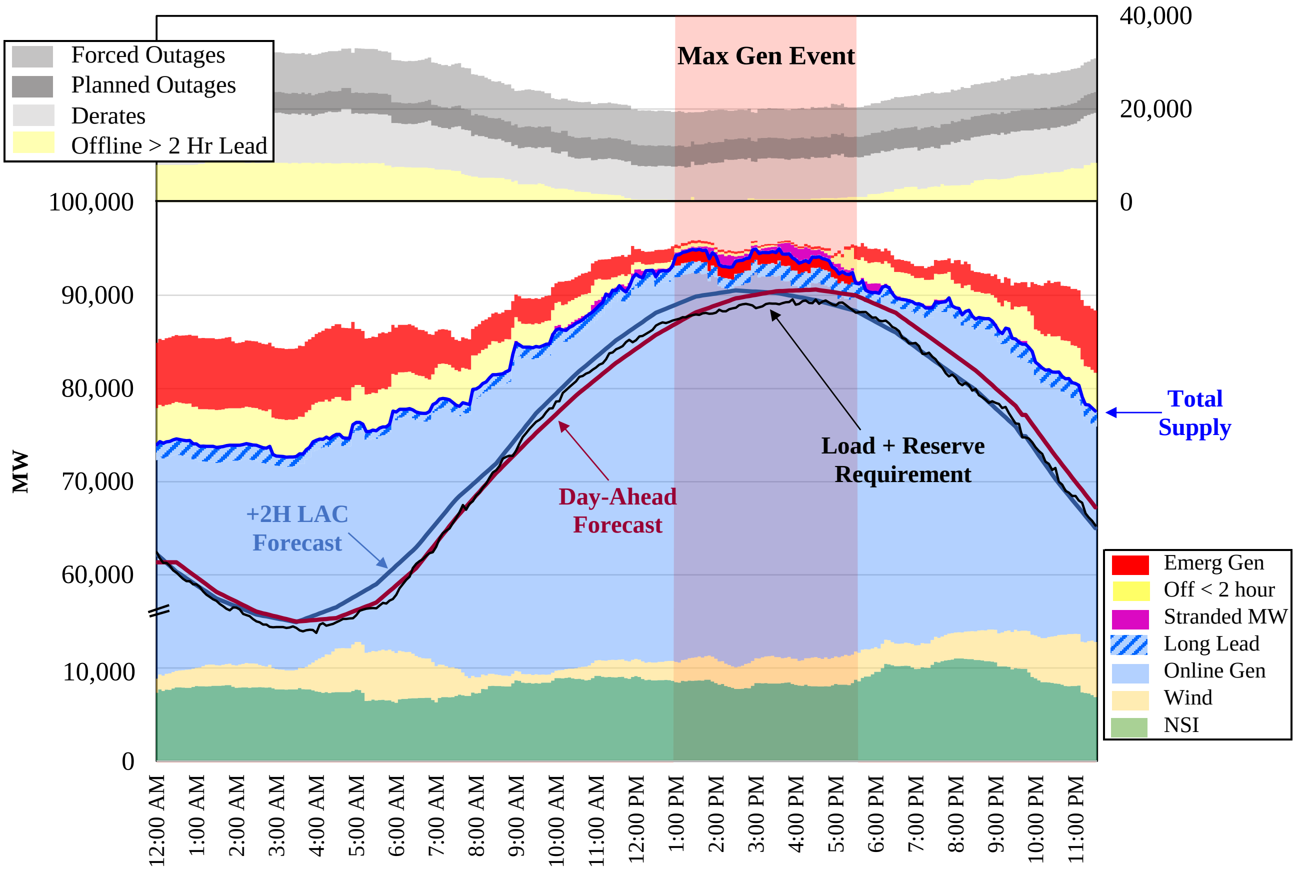

Figure 6 illustrates conditions in MISO between July 6 and 10 from 11 a.m. until 6 p.m. The tightest conditions during the week occurred on July 6 and MISO declared Conservative Operations. Although temperatures and load were not quite as high on this day, wind output was

11 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.

very low. As shown in the figure by comparing the black actual load line to the blue two-hour forecast line and the maroon day-ahead forecast line, MISO's load forecast had substantial errors on multiple days. Throughout the week, large storms developed over significant population centers that caused load to fall sharply during the peak hours of the day. Day-ahead forecast errors were as high as 7 to 8 percent on July 8 and 10, for example. July 8 was the hottest day of the week and exhibited the highest day-ahead forecasted load. Wind output on that day was very high and contributed to a large supply margin, as shown in the yellow area in the figure above.

We separately show conditions on July 7 in Figure 7. At 1 p.m. on the 7th MISO declared a Maximum Generation Event that quickly was elevated to an Emergency Event Step 1a in the North and Central Regions, which led to a commitment of all available resources. During the morning ramp hours, temperatures and corresponding load rose more than expected. MISO's declaration granted access to more than 400 MW of emergency-only resources. The emergency offer floor price of $737.66 per MWh did not set the price. Afternoon storms flattened the load across the peak, and ultimately, the emergency conditions did not materialize.

**Figure 7: Maximum Generation Event**
July 7, 2020

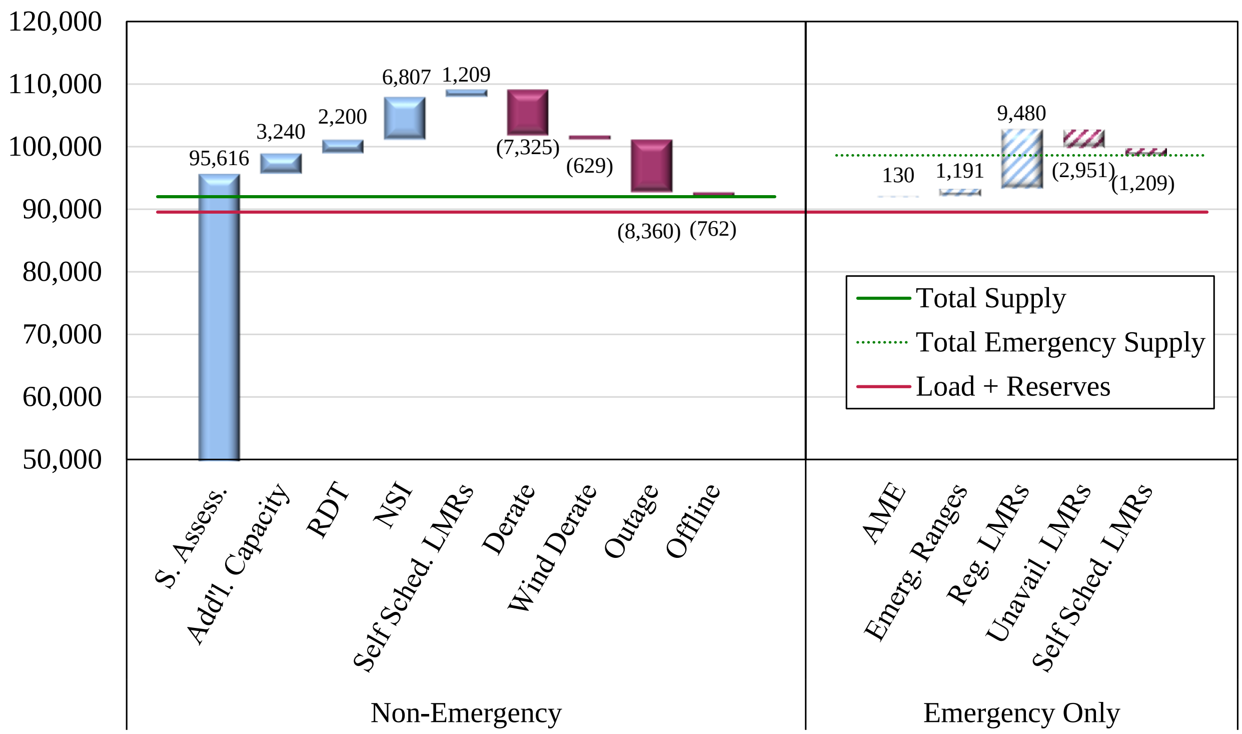



As shown in Figure 8 below, more than 17 GW of capacity was unavailable during the peak hour during the declared emergency. The blue columns on the left indicate the amount of available capacity during the event, including Installed Capacity (ICAP) of resources included in the 2020 Summer Assessment, additional capacity that was made available to MISO above the ICAP, available transfers across the RDT, imports, and self-scheduled LMRs. Farther to the right, in the maroon bars, we indicate capacity that was unavailable during the event due to derates, wind derates, units on outage, and units that were offline.

In the right panel, we show in the hatched blue bars emergency-only generation that was available in the region, to include AME, emergency ranges of online resources, and registered LMRs. Farther to the right we show unavailable emergency-only resources in the maroon hatched bars, to include unavailable LMRs. The solid horizontal maroon line indicates the total requirement during that hour, the solid green line represents the total available supply, and the dotted green line shows the total available supply including emergency-only resources.

**Figure 8: Peak Hour Midwest Capacity Availability**

Midwest Region July 7, 2020, Hour Beginning 16



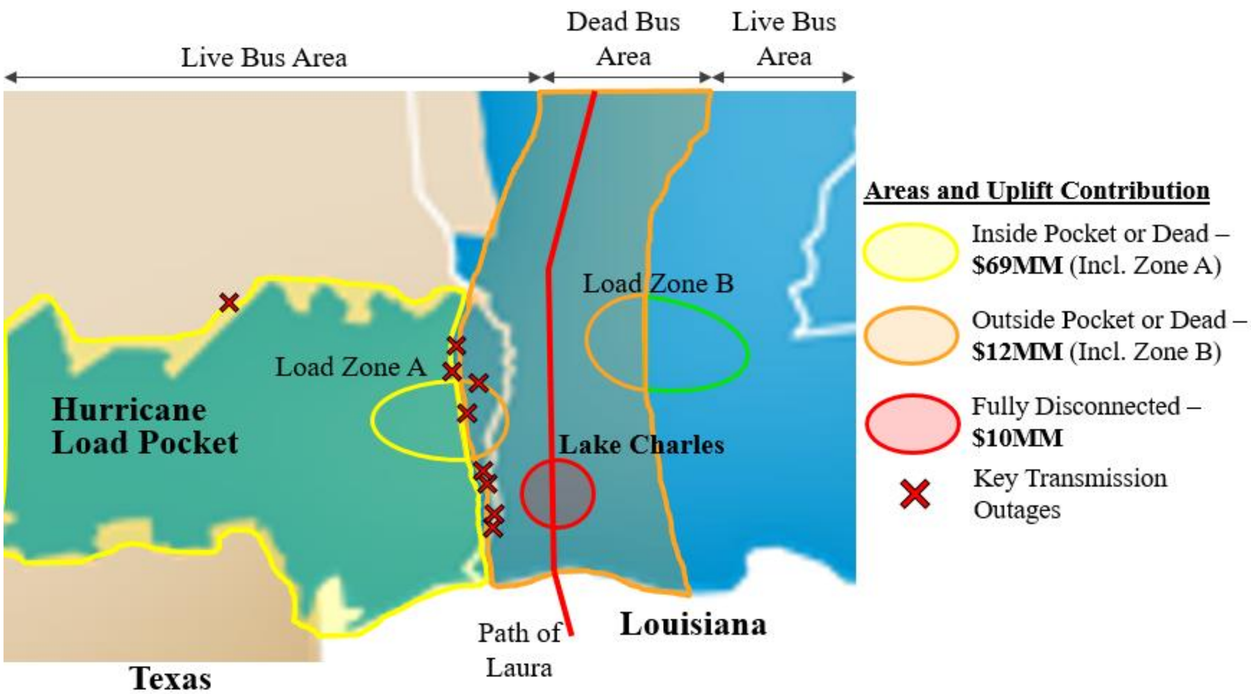

As shown in Figure 8, more than 8 GW of capacity was unavailable during the event because of outages, and additionally more than 7 GW of capacity was unavailable because of derates. We have recommended that MISO reform capacity accreditation to an availability-based approach to provide stronger incentives for resources to be available during emergency events, such as on July 7th.

On July 9, MISO declared a Transmission System Emergency from 4:10 p.m. to 7 p.m. to help manage two parallel constraints that were impacted by outages. The declaration was intended to allow MISO to access the emergency ranges of online resources. IESO was in an EEA 1 condition and had reduced imports into Michigan by 700 MW. A critical unit that would have provided significant congestion relief was unavailable because of a COVID-19 outbreak at the plant. This caused a significant amount of congestion to accrue in Michigan on that day.

#### *Hurricane Laura in MISO South*

On August 27, Hurricane Laura made landfall as a category 4 hurricane near Lake Charles, LA, resulting in substantial damage to the transmission system. A large swath of dead buses (buses disconnected from the grid) in the path of the hurricane effectively isolated the Western Load pocket and a greater part of WOTAB from the rest of MISO. This new region was designated as the Hurricane Laura Load Pocket (HLLP). More than 6,000 MW of generation was forced out of service in Eastern Texas and Western Louisiana, and MISO declared an emergency load shedding of more than 500 MW of firm load in the Western Load Pocket. Figure 9 below illustrates the path of hurricane, the location of the HLLP, and various areas that we identified where we believe pricing was either reflective of conditions or inappropriate. We provide a discussion on this in more detail below.

**Figure 9: Hurricane Laura Load Pocket**
*August 27, 2020*




Multiple generators took outages in anticipation of the storm and several units tripped during the event, causing MISO to shed load in the HLLP and declare that all affected nodes were priced at Value of Lost Load (VOLL) in real time. Ex-ante prices averaging $15 per MWh during the event in the HLLP did not reflect the VOLL because software limitations prevented MISO from posting the VOLL prices. MISO had to manually redispatch multiple units to the top of their offered ranges. A week later, MISO implemented revised settlements at $3,500 per MWh (based on VOLL) for several hours, leading to approximately $90 million in balancing congestion.

Hurricane Laura effectively created a "dead zone" in the path of the storm, as indicated in the orange-bordered area in Figure 9, destroying a significant amount of distribution system lines and transmission. Approximately $10 million in balancing congestion on August 27 was due to dead bus pricing at $3,500 per MWh in the impacted Lake Charles area. We have questioned the appropriateness regarding applying the VOLL pricing to "dead buses" outside the HLLP (including Lake Charles), which accounts for roughly 25 percent of the balancing congestion.

Due to modeling challenges, MISO was unable to price the HLLP consistent with the prevailing conditions until a week into September. Up to a week after the storm, supply shortages prevented MISO from serving industrial load in the area while prices were averaged only around $20 per MWh on peak. MISO established a reserve zone and activated a Reserve Procurement Enhancement (RPE) constraint on September 8 so prices could reflect the tight conditions in the region. By then much of the transmission had been restored and conditions were much less tight. Total restoration of the area was not completed until mid-October.

The events on August 27$^{th}$ raise both energy and capacity market concerns. MISO's current VOLL of $3,500 per MWh is inefficiently low. MISO would have lost of up to 830 MW from a key resource (a non-capacity resource) to the ERCOT market if ERCOT had experienced tight conditions, since ERCOT will set prices up to $9,000 per MWh. We have recommended that MISO update the VOLL used in shortage pricing based on data from the Midwest to $23,000 per MWh. Additionally, we have been recommending MISO define local capacity zones consistent with electrical constraints in order to send better economic signals. The capacity market does not reflect the Western Load Pocket and, thus, produced inefficient results for this area in the 2020–2021 Planning Resource Auction. A large resource that straddles MISO and ERCOT and could have provided an additional 800 MW of UCAP did not clear the 2020–2021 PRA. Fortunately, this resource voluntarily switched to MISO and provided energy to the pocket on August 27, or the load shed would have been larger.

#### *Hurricane Delta in MISO South*

On October 10, Hurricane Delta made landfall just east of the area impacted by Hurricane Laura, although the swath of impacted area was less extensive. Because MISO had established a reserve zone for the HLLP, pricing in the load pocket reflected tight conditions in the area. On October 10 and 11, there was a $45 day-ahead premium to procure reserves in the newly established reserve zone for the HLLP. In response to prices, some resources returned from outage early and a non-capacity resource switched from ERCOT to MISO.

# 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.

Fortunately, MISO's markets are fundamentally 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. In this chapter, we discuss the key issues 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 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. 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. MISO's interconnection queue is comprised of mostly renewable resources. MISO currently has more than 700 active projects in the interconnection queue, totaling nearly 110 GW, and more than two thirds of these are solar projects and another 20 percent are wind projects.[12] 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 massive 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 10 shows the anticipated mix of 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 bracket the possible growth in renewables that MISO anticipates through 2040.

12 MISO Futures Report, April 2021, https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

**Figure 10: Anticipated Resource Mix**
By Fuel Type

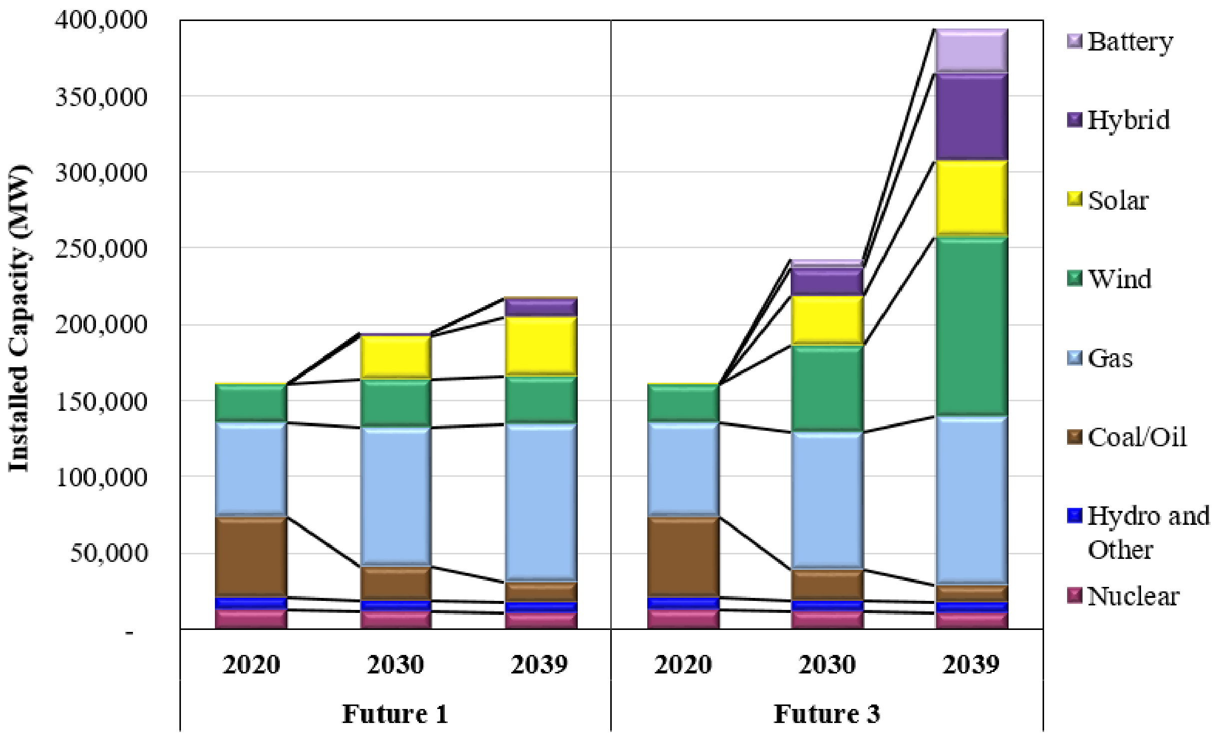
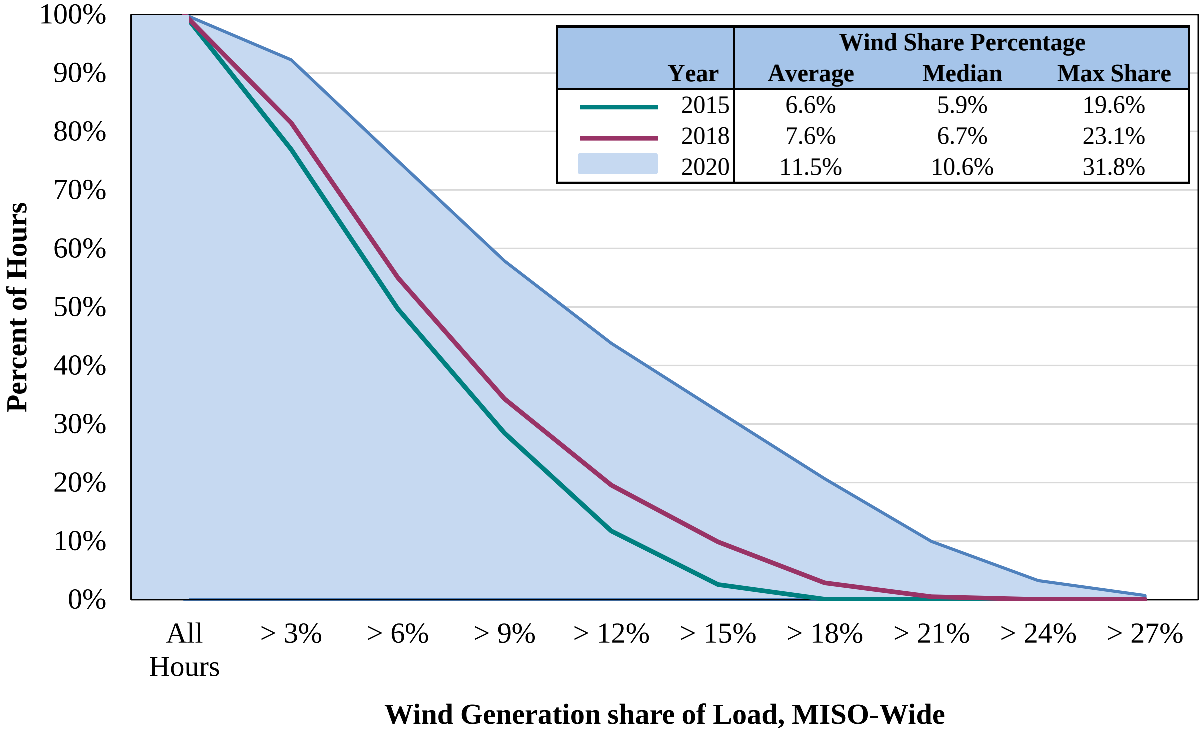



Figure 10 shows that both scenarios forecast substantial penetration of solar resources in the coming years, which is likely based on the fact that solar resources dominate the interconnection queue. Both scenarios also show that coal-fired resources are likely to retire rapidly over the next 10 years, 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.

### *Expansion of Wind Resources*

Wind output continued to grow in 2020, rising more than 25 percent from 2019 to exceed 8 GW on average. Hence, wind resources continue to produce increasing shares of the total generation in MISO, increasing from 9 percent of all energy in 2019 to 12 percent in 2020. 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 2020, which presents increasing operational challenges that MISO must confront. Figure 11 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 share of load prevailed. So, for example, in 2020, in 50 percent of the hours, at least 12 percent of the load was served by wind.

**Figure 11: Share of MISO Load Served by Wind Generation**
2015–2020

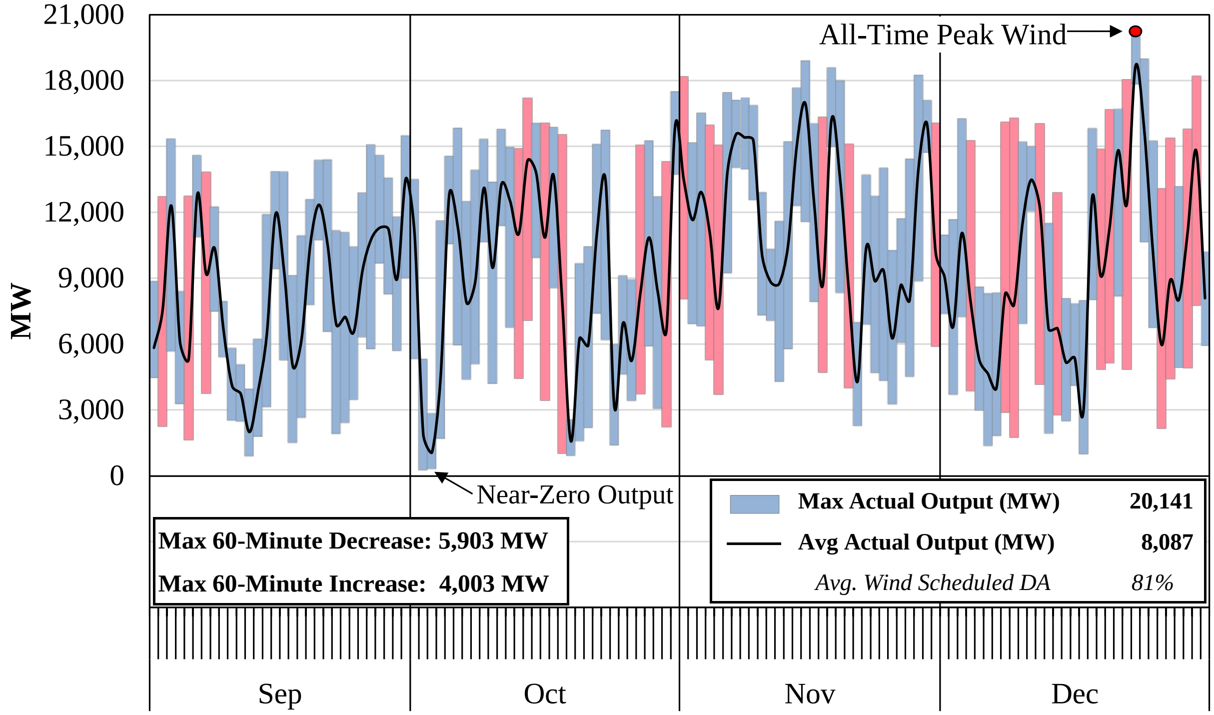



This figure shows that wind output as a share of load in MISO has been growing rapidly. To see the changes over time, notice in the figure that for half of the hours of the year, wind was serving more than 6 percent of the load in 2015 and a little more in 2018, versus more than 12 percent of the load in 2020. We expect this trend to continue and, as wind generation increases, the operational challenges of managing this generation will increase.

*Wind Fluctuation*. 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. To illuminate these challenges, Figure 12 shows the daily range in wind output along with the average wind output each day from September through December 2020, a period during which wind output was relatively high. This period included a new all-time peak wind output above 20 GW for the first time on December 23, a day in which wind served more than 30 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. Particularly sharp changes in output can be more difficult to manage because MISO is limited in how quickly it can move other resources. The figure reports that wind dropped by as much as 5,900 MW in one hour during this period. As penetration increases, the need to have other flexible resources available to manage the intermittent output will rise.

**Figure 12: Daily Range of Wind Generation Output**
September – December 2020




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 12 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.

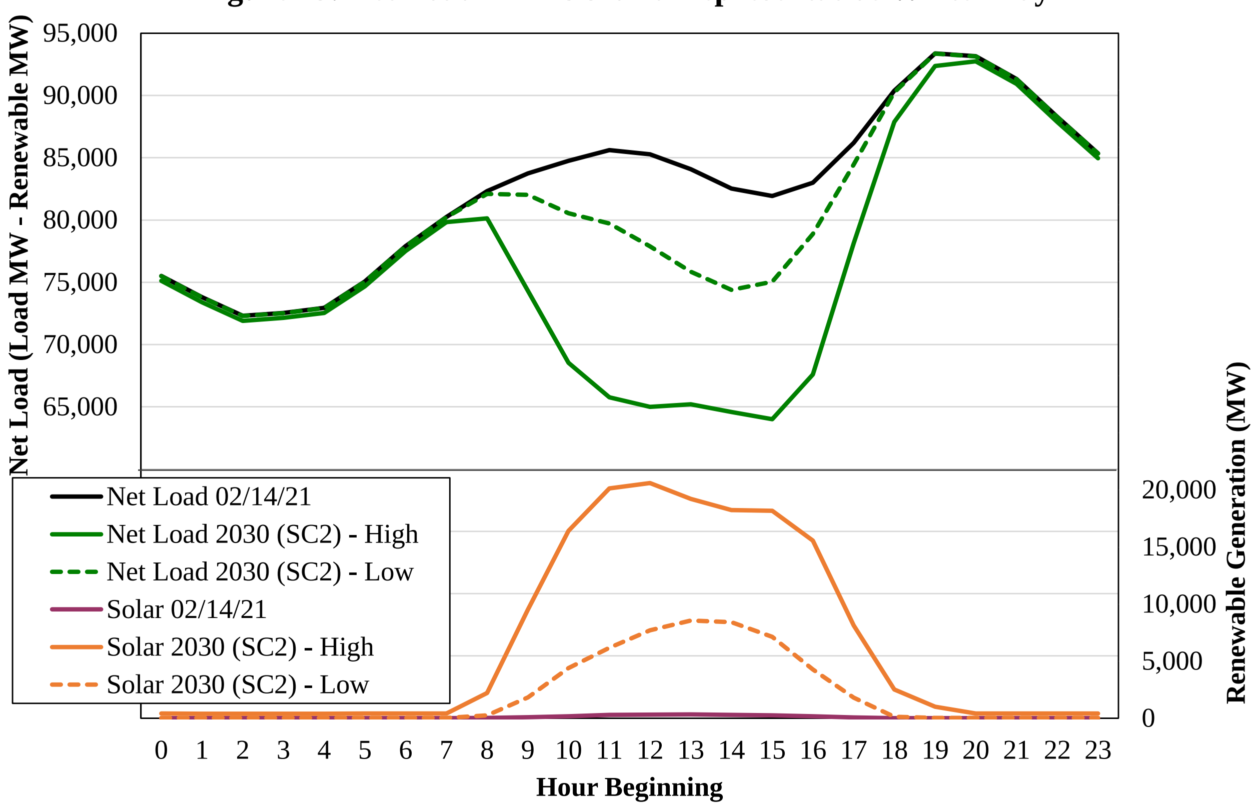
*Transmission Congestion Caused by Wind.* In addition to the issues caused by the volatility of wind output, the concentration of wind resources in the western areas of MISO's system has created growing network congestion in some periods that can be difficult to manage. MISO's Dispatchable Intermittent Resource (DIR) type has been essential in allowing MISO to manage congestion caused by wind output. DIR participation by wind resources provides MISO much more timely control over its 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 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 10 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.

Given the timing of the expected increases and decreases in the output from solar resources in MISO, a large quantity of these resources would 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 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. A second demand to ramp up conventional resources will occur as solar output falls off sharply in the evening hours. 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 Western markets. Figure 13 shows the "net load" that must be served by conventional resources in MISO under different solar penetration scenarios.

**Figure 13: Net Load in MISO on a Representative Winter Day**




In the 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. The level of 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. 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 Stored Energy Resources (SERs). MISO has discussed many of the challenges that are anticipated to arise from these 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, which will likely be very challenging.[13]

According to the 2019 OMS DER Survey, more than 4,500 MW of DER currently exists in MISO, and approximately one third is residential. Nearly half of this is solar PV and the rest are other DER types that include battery storage, demand response, and small-scale generation. We do not anticipate large-scale entry of DER resources, but MISO should be prepared for them 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 and 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.

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

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

### *Energy Storage*

Order No. 841 required MISO to enable Energy Storage Resources (ESRs) to participate in the market recognizing the operational characteristics of ESRs. Figure 10 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. ESR costs 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.

However, 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 very important to adopt an accurate accreditation methodology for ESRs, something we discuss in the following subsection.

## B. The Evolution of the MISO Markets to Meet Future Challenges

To date, MISO has managed the growth in intermittent resources reliably. However, MISO concluded that if it exceeds 30 percent intermittent renewable generation, the additional renewable resources would present substantial challenges to reliability. This conclusion was based on its study of the potential implications of differing wind/solar penetration levels under the RIIA that began in 2018.[14]

Some have suggested that fundamental changes in MISO's markets and operations are needed in response to this dramatic change in its 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 high 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 providing incentives for participants to use it; and
- Modifying its settlement rules to improve generators' incentives to follow dispatch instructions.

As the fleet transitions, some needs may arise that are not currently satisfied by the market, such as increased needs for voltage support in some locations or system-wide needs for inertial

14 See: https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment.

support. 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 as the system changes over the next decade can be addressed with the following key improvements to the MISO markets that we discuss in this subsection:

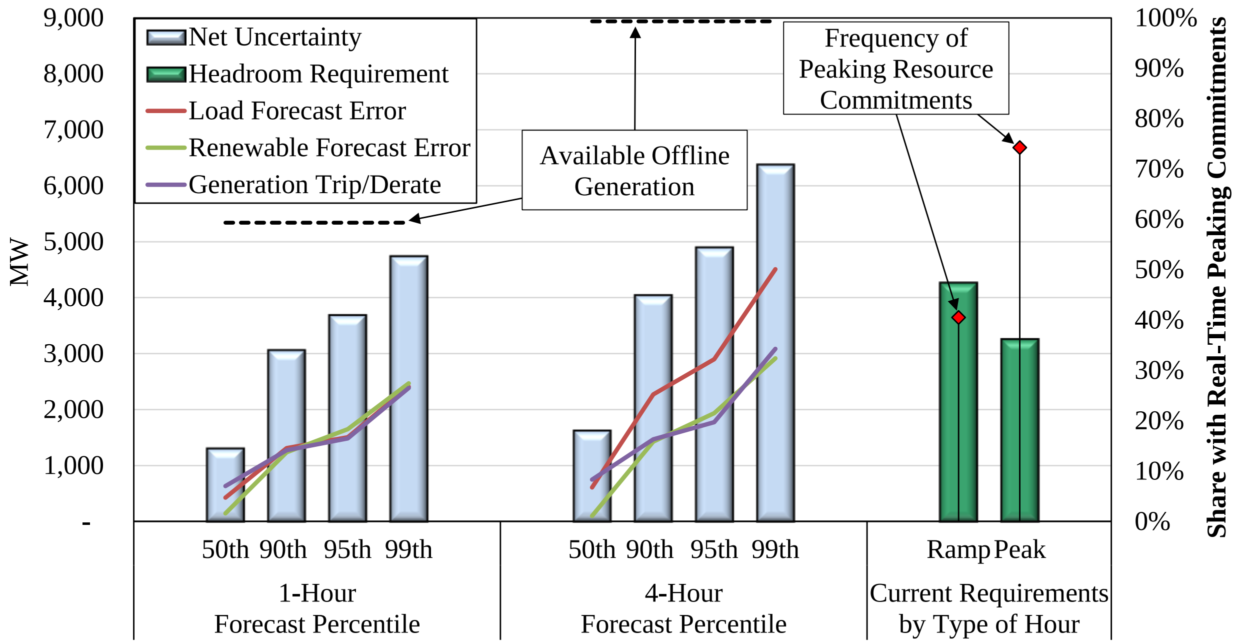
- Implementation of an uncertainty product to reflect MISO's current and future need to commit resources to have sufficient supply available in real time to manage uncertainty.
- Improvement of its shortage pricing to compensate the resources that are available and flexible that allow MISO to maintain 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.
- Reform of capacity accreditation to allow resources' capacity credit under Module E to match their reliability value.

***Uncertainty Product and Look-Ahead Dispatch***

As MISO transitions to a fleet that is far more dependent on intermittent resources, supply uncertainty will markedly increase. This uncertainty will affect both MISO's planning and operations. MISO has correctly concluded that the availability and flexibility of its non-intermittent resources will be paramount in maintaining its ability to operate the system reliably. Figure 14 shows the uncertainty that MISO currently faces on average and in the worst hours, both one hour ahead and four hours ahead. It also shows the amount of offline generation available within these timeframes that it can commit to address this uncertainty. In comparison, it shows the headroom MISO seeks to hold in reserve in different types of hours to be able to respond to the uncertainty and operate the system reliably. It also shows how frequently MISO commits peaking resources in these hours to meet these requirements. For additional details on this analysis, see Section III of the Analytical Appendix.

Figure 14 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, and the associated RSG would largely disappear.

**Figure 14: Uncertainty and MISO's Operating Requirements**
August 2019 to February 2021




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 that MISO consider implementing this product along with its existing products through a look-ahead dispatch (LAD) model that would optimize the dispatch of resources in future periods of up to four hours.

### *Shortage Pricing in MISO*

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 be embedded in all higher-value products, including energy. This 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 ultimately 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 that ranged from $3,600 to $3,900 per MWh, and a VOLL for manufacturing and non-manufacturing commercial customers that ranged from $32,000 and $73,000 per MWh, respectively.[15] Weighting these values based on the load data in MISO from 2018 yields an average VOLL of $23,000 per MWh. We recommend MISO adopt this VOLL or a comparable value.

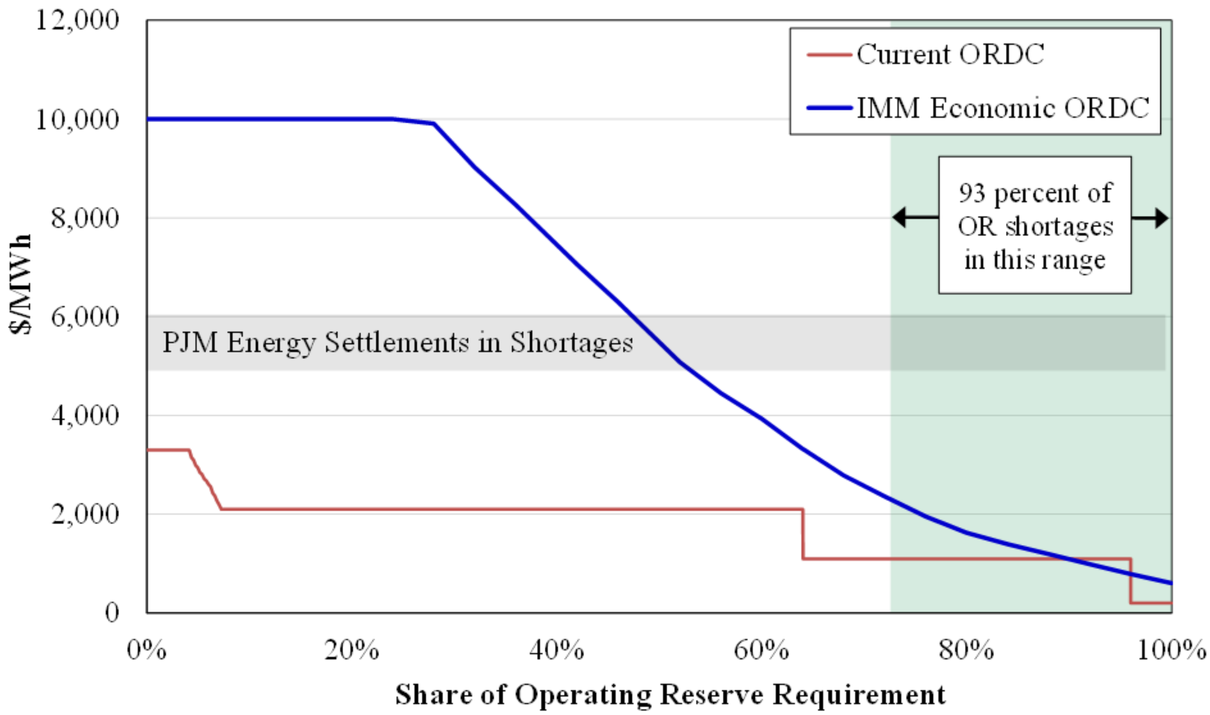
*Improving the Slope of the ORDC.* The slope of the ORDC is determined by how the probability of losing load changes as the level of operating reserves falls. The probability of losing load depends on accurately estimating the vast combinations of random contingencies and conditions that could occur when MISO is short of reserves. To model these random occurrences, we estimated the probability of losing load using a Monte Carlo simulation.[16] 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.

15 We did not include small commercial and industrial loads from the Berkeley model as the VOLL values were much higher and we did not find them to a reasonable reflection of the VOLL in MISO for reasons detailed in Section III.B of the Analytic Appendix.

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

The results of our recommended VOLL and improved ORDC slope is reflected in the IMM's Economic ORDC that is shown in Figure 15 as the royal blue line. The figure also shows MISO's current ORDC, which is significantly understated for almost all shortage quantities. This has prevented MISO's markets from pricing shortages efficiently.

**Figure 15: 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.

### *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 increase in distances 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 as "grid optimization." 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.[17] 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 markets systems. We recommend that MISO anticipate this need in the near term because the benefits of such improvements are likely to grow substantially as MISO's generating fleet transitions over the next decade.

### *Objectives for Accommodating Distributed Energy Resources*

In response to FERC Order 2222, MISO is engaging stakeholders and holding workshops to identify technical, reliability, and market 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 that these changes will result in efficient

[17] 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.

incentives for DERs and non-DERs. To achieve these two goals, we recommend that MISO address the following primary objectives:

- *Comparable and Verifiable Product Performance*. DERs participating in energy markets should have comparable performance and verification requirements to other types of resources. The settlements should reflect the relative value of the DERs.
- *Distinguish Between Controllable and Uncontrollable*. DERs that are not controllable (e.g., rooftop solar, energy efficiency) presents additional forecasting challenges and does not support reliability in the same manner as controllable DERs. Additionally, efficiently utilizing controllable DERs will require different processes and tools.
- *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. If MISO over-accredits DERs in the capacity market, it will increase the incentives to invest in DERs and reduce the incentive to invest in other types of resources that are essential for maintaining reliability.

DERs may present new challenges that arise because a larger percentage of the system's supply is not controllable on the same basis as MISO's current conventional generation. The evolving rules should provide efficient incentives to be controllable and require visibility and verification, which will be fundamental to integrating DERs reliably.

## C. Capacity Planning and Accreditation

As the system evolves, the availability and flexibility of resources throughout the year will be increasingly important. Tight market conditions are no longer occurring predictably in the summer season, a trend that is likely to continue as fluctuations in intermittent output and transmission constraints contribute to tight conditions in local areas. Resources provide value to the system to the extent that they can support reliability during these conditions. Unfortunately, MISO's current accreditation that considers only forced outages is becoming increasingly inaccurate in granting capacity credits that reflect resources' relative contributions to reliability.

The current UCAP values are determined by discounting a resource's total installed capacity using forced outages that participants self-report to GADS.[18] This is problematic because:

- Other types of outages and derates also reduce MISO's access to capacity resources and result in the same reliability impacts as forced outages;
- Suppliers do not completely report their outages and derates;
- Less reliable resources that are rarely needed are credited as fully available when they are not asked to run, inflating their UCAP levels; and
- Long-lead time resources that are frequently offline provide far less value than their UCAP level because when tight conditions arise unexpectedly, they cannot be utilized.

Energy-only markets do not face this problem because shortage revenues are received only by units that are producing energy or reserves during shortage conditions. In RTOs that rely on a capacity market to help facilitate long-term investment, capacity revenues should ideally be distributed in a manner that is comparable to the distribution of shortage revenues—i.e., to resources that are available and supporting the system during the tightest conditions.

Therefore, we recommend MISO improve its accreditation methodology by basing it 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. These changes would result in sizable accreditation improvements by causing the accreditation to reflect the relative reliability contribution of each resource. By rewarding flexible resources, this recommendation will help MISO maintain future reliability in the face of increased uncertainty related to intermittent output and other factors. We further analyze this accreditation methodology in Section VII.G.

This recommendation will improve the accreditation of MISO's conventional resources, but is not ideal for non-conventional resources, such as DERs, solar resources, wind resources, ESRs and hybrid facilities. Currently, MISO estimates the Effective Load Carrying Capability for wind resources, which 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. The ELCC methodology developed for wind resources allows them 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, we recommend that MISO develop ELCC methodologies for these resource types.

18 Exceptions exists for LMRs that receive additional capacity credit associated with the PRMR value and transmission losses, and intermittent resources whose accreditation is based on the ELCC methodology.

# IV. Day-Ahead Market Performance

MISO's electricity spot markets operate together in a two-settlement system, clearing once in the day-ahead market and resettling imbalances in the real-time market. The day-ahead market operates in advance of the real-time market and is largely financial, establishing financially-binding, one-day forward contracts for energy and ancillary services.[19] The real-time market clears based on actual physical supply and demand. Supply or demand cleared day-ahead settle any deviations at real-time prices.[20] Based on our evaluation herein, we have concluded the day-ahead market performed competitively in 2020. The performance of the day-ahead market is important for the following reasons:

- 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;[21]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market; 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).

## A. Summary of Day-Ahead Outcomes

Most of the settlements in MISO occur through the day-ahead market, as roughly 97 percent of MISO's load clears in the day-ahead market (net of virtual transactions and changes in net interchange). This small average difference in net load scheduling indicates that modeling in the day-ahead and real-time markets are consistent. The day-ahead energy prices averaged $22 per MWh in 2020, down 16 percent from 2019. Congestion caused prices at the day-ahead hubs to range from $18 per MWh at the Minnesota Hub to $25 per MWh at the Michigan Hub. These results converged well with the real-time market results as discussed in the next subsection.

The primary difference between the day-ahead and real-time markets is that 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 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 that MISO evaluate the feasibility of transitioning to a 15-minute day-ahead market.

19 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.

20 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.

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

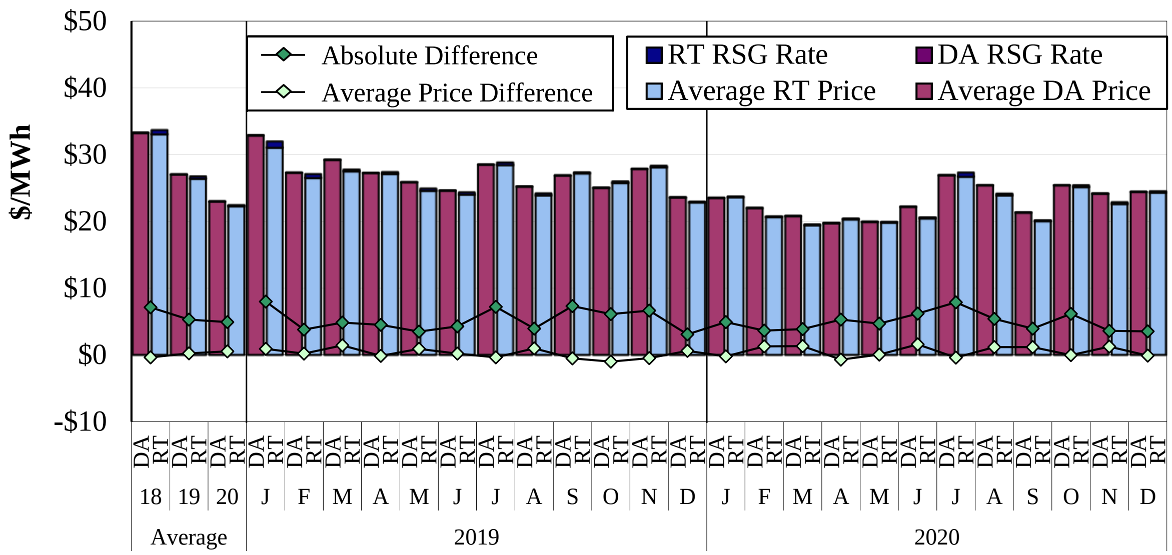
## B. Price Convergence with the Real-Time Market

Day-ahead market performance is primarily evaluated by the degree to which it converges with real-time market outcomes. 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 16 shows monthly and annual price convergence statistics. The upper panel shows the results for the Indiana Hub, while the table below shows seven hub locations in MISO. 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 table shows the average price difference adjusted to account for the difference in RSG charges.

**Figure 16: Day-Ahead and Real-Time Prices**

2019–2020




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

| | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Indiana Hub | -1 | 1 | 2 | 3 | 1 | 5 | -1 | 4 | 1 | -1 | 4 | -2 | -4 | -2 | 3 | -1 | 6 | 7 | -3 | 0 | 8 | -2 | 5 | 6 | 0 | 5 | -1 |
| Michigan Hub | -1 | -1 | 1 | -6 | 0 | 4 | -2 | 3 | 1 | -5 | 4 | 1 | -4 | -1 | 3 | -2 | 6 | 7 | -6 | 4 | 3 | -5 | 3 | 6 | -2 | 5 | -1 |
| Minnesota Hub | -1 | 1 | -2 | -4 | -1 | 4 | 0 | 4 | 2 | -3 | 6 | 1 | 0 | 2 | 5 | -4 | 7 | 3 | 1 | 0 | -5 | -3 | 1 | 0 | -4 | -3 | -7 |
| Arkansas Hub | -1 | 1 | 1 | 0 | -3 | 5 | 1 | 6 | 8 | -1 | 2 | -2 | -4 | -3 | 4 | 0 | 4 | 6 | 5 | 6 | 6 | -7 | 2 | 3 | -5 | 0 | 1 |
| Louisiana Hub | -2 | 5 | 2 | 3 | 0 | 15 | 9 | 11 | 10 | 0 | 6 | 2 | 1 | -3 | 2 | 0 | -2 | 12 | 4 | 5 | 6 | 1 | 0 | 8 | -5 | 1 | 3 |
| Texas Hub | -1 | -1 | 6 | 1 | 1 | 7 | 0 | 9 | 1 | 5 | -18 | 1 | -16 | -1 | 4 | 1 | 6 | 10 | 5 | 13 | 7 | 2 | 3 | 6 | 9 | 4 | 1 |

Convergence was good overall. Day-ahead premiums were less than one percent on average after adjusting for the real-time RSG, which averaged $0.20 per MWh. Divergence occurred because of transient conditions in 2020:

- In March, commitments for transmission in real time led to a high day-ahead premium at the Texas and Louisiana Hubs, since they are not reflected in the day-ahead market.

- In June, relatively high real-time wind during the first week contributed to a high day-ahead premium in the overall system marginal price.
- In May, an SPP market-to-market constraint that was binding in the day-ahead market and not in real time led to a 13 percent day-ahead premium at the Texas Hub.
- In October, MISO's modeling of the Reserve Procurement Enhancement (RPE) in the newly created Hurricane Laura Load Pocket in anticipation of Hurricane Delta contributed to a day-ahead premium at the Texas Hub.

The market can be slow to react to these periods of substantial real-time congestion, in part because participants must engage in high-risk day-ahead market trades (i.e., virtual load at some locations and virtual supply at others) to arbitrage these differences. We have recommended a virtual spread product discussed below to improve the market's performance in this area.

## C. 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 17 shows the average offered and cleared virtual supply and virtual demand in the day-ahead market.

**Figure 17: Virtual Demand and Supply in the Day-Ahead Market**
2020

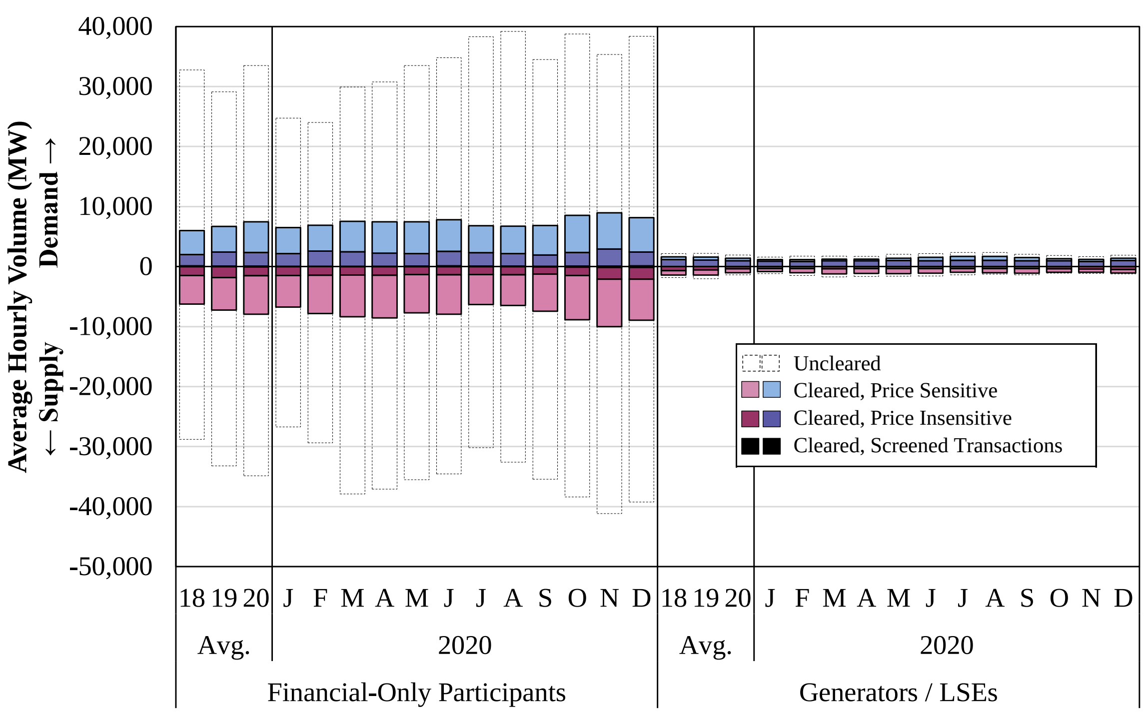


Figure 17 shows that offered virtual volumes increased by 9 percent over last year, driven by a 15-percent increase in virtual demand offers. Average cleared transactions also rose 5.3 percent, largely driven by financial-only participants whose cleared virtual demand increased by 12 percent over 2019. Average cleared virtuals in the Midwest grew by 14 percent, whereas average cleared virtuals in the South fell by 11 percent, driven by a 17 percent drop in cleared virtual demand. This was likely a response to the persistent day-ahead premium at the Texas and Louisiana Hubs.

Financial participants account for the vast majority of the virtual activity in MISO, as few generators and LSEs hedge their generation or load positions using virtual transactions. Financial participants, who tend to offer more price-sensitively, provided 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 clear. These transactions are beneficial because they mitigate particularly large day-ahead price movements.

Figure 17 distinguishes between bids and offers that are price-sensitive and those that are price-insensitive (i.e., those that are very likely to clear). Price-sensitive transactions provide more liquidity in the day-ahead market and facilitate price convergence. Price-insensitive transactions effectively indicate a preference for the transaction to clear regardless of the price.[22] These transactions constitute a large share of all virtual transactions, and occur for two primary reasons:

- To establish an energy-neutral position between two locations to arbitrage congestion-related price differences between the day-ahead and real-time markets. We refer to these transactions as “matched” transactions; and
- To balance the participant’s portfolio to avoid RSG deviation charges assessed to net virtual supply, which is deemed to cause RSG under MISO’s cost allocation.

The average hourly volume of matched transactions in 2020 fell by 4 percent from 2019 to 636 MW. Matched transactions are used to arbitrage congestion-related price differences while avoiding energy price risk. We continue to recommend MISO implement a virtual spread product that would allow participants to engage in such transactions price-sensitively. This product would allow participants to specify the maximum congestion between two points they are willing to pay for a transaction. Comparable products exist in both PJM and ERCOT.

Finally, price-insensitive bids and offers that contribute to a significant congestion divergence between the day-ahead and real-time markets are labeled “Screened Transactions” in the figure.

22 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).

We investigate these trades because they may be attempts to manipulate day-ahead prices. The screened transactions share was less than one percent and did not raise concerns in 2020.

## D. Virtual Activity and Profitability

To provide perspective on the virtual trading in MISO, Table 2 compares virtual trading in MISO to trading in NYISO and ISO New England.

**Table 2: Comparison of Virtual Trading Volumes and Profitability**
2020

| Market | Virtual Load | | Virtual Supply | |
|---|---|---|---|---|
| | MW as a % of Load | Avg Profit | MW as a % of Load | Avg Profit |
| **MISO** | 12.1% | $0.10 | 12.3% | $0.99 |
| **NYISO** | 7.9% | $0.39 | 13.8% | -$0.05 |
| **ISO-NE** | 2.8% | $0.43 | 4.8% | $0.78 |

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 efficient cost allocation of RSG 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 they are allocated the RSG they are deemed to have caused.

Gross virtual profitability increased by 29 percent in 2020 to average $0.55 per MWh, largely because of the increase in the profitability of virtual demand from -$0.07 in 2019 to $0.10 in 2020. Hurricane Laura in August and Hurricane Delta in October in the South contributed to significant differences between the day-ahead and real-time prices. Virtual profitability around those events was generally high.

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 net virtual supply. Virtual demand does not bear capacity-related RSG costs because they are a “helping deviation.” Virtual transactions by financial participants remained generally more profitable than transactions submitted by physical participants, averaging $0.63 per MWh compared to $0.04 per MWh.

The fact that virtual transactions are profitable on average is desirable because profitable transactions generally promote convergence between day-ahead and real-time prices. However, 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.

## E. Benefits of Virtual Trading

We conducted an empirical analysis of virtual trading in MISO in 2020 that evaluated the contribution of virtual trading to the efficiency of the market outcomes. We determined that 57 percent of all cleared virtual transactions in MISO were efficiency-enhancing and led to convergence between the day-ahead and real-time markets. The majority of efficiency-enhancing virtual transactions were profitable based on congestion modeled in the day-ahead and real-time markets and the marginal energy component (system-wide energy price).

A small share of the efficiency-enhancing virtual transactions were 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.H.

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 3 shows the total amount of efficient and inefficient virtual transactions by market participant type.

**Table 3: Efficient and Inefficient Virtual Transactions by Type of Participant in 2020**

| | Financial Participants | | | Physical Participants | | |
|---|---|---|---|---|---|---|
| | **MWh** | **Convergent Profits** | **Rent-Seeking** | **MWh** | **Convergent Profits** | **Rent-Seeking** |
| **Efficiency Enhancing (Profitable)** | 68,432,571 | $519.9M | $.6M | 9,815,793 | $57.1M | $1.1M |
| **Efficiency Enhancing (Unprofitable)** | 10,115,526 | -$37.4M | $4.3M | 1,689,348 | -$4.8M | $.6M |
| **Not Efficiency Enhancing (Profitable)** | 3,150,611 | -$6.2M | $18.5M | 707,249 | -$.8M | $2.0M |
| **Not Efficiency Enhancing (Unprofitable)** | 53,589,334 | -$411.8M | -$3.3M | 9,131,270 | -$54.6M | $.2M |
| **Total** | **135,288,041** | **$64.6M** | **$20.1M** | **21,343,661** | **-$3.1M** | **$4.0M** |

The table shows that 57 percent of all virtual transactions were efficiency-enhancing. Convergent profits were positive on net for all virtual transactions by $61.5 million, up from $32.7 million in 2019. 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 all of 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 2020.

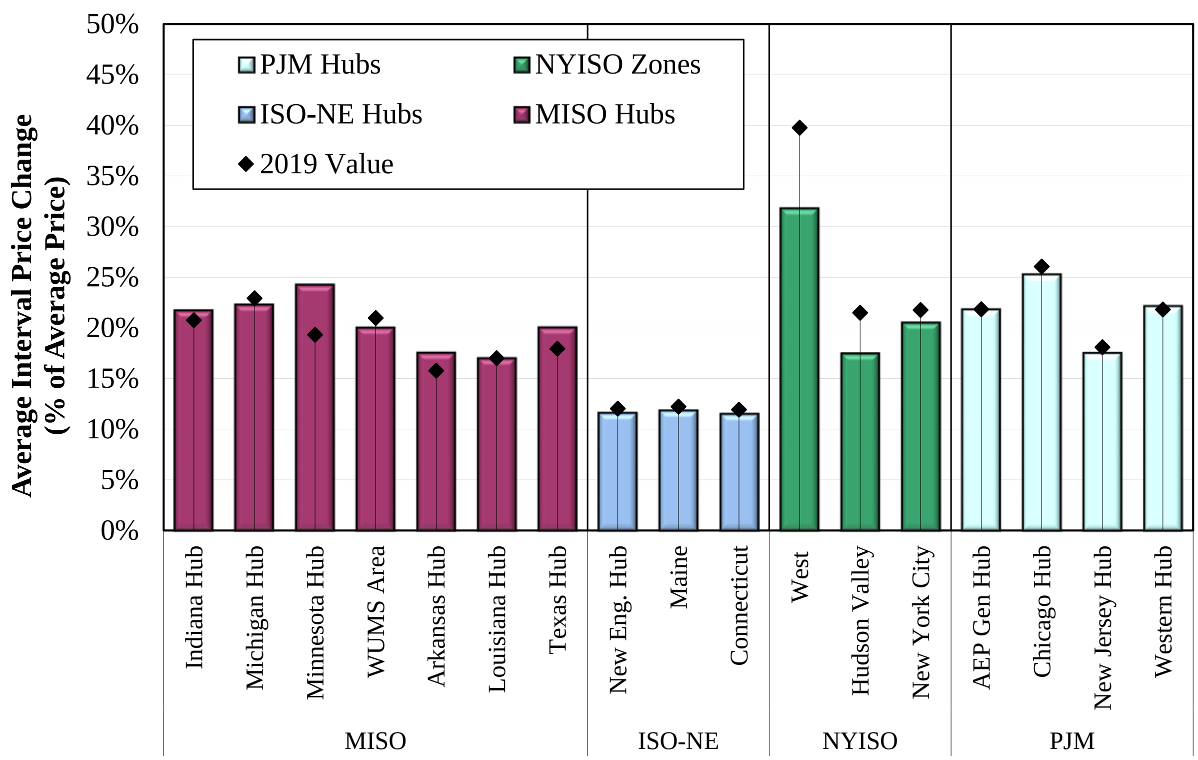
# V. Real-Time Market Performance

The performance of the real-time market is crucial because it governs the dispatch of MISO's resources and sends economic signals that facilitate scheduling in the day-ahead market and longer-term investment decisions. This section evaluates two broad aspects of the real-time market: real-time pricing and real-time market operations. In the pricing area, we summarize price volatility and the effectiveness of the Extended Locational Marginal Pricing (ELMP) model to allow peaking resources and emergency resources to set prices. Our review of operational issues includes: (a) uplift costs that are generally caused by operator actions, (b) the management of flows over the RDT interface between the Midwest and the South, (c) the dispatch of MISO's intermittent wind resources, and (d) outage scheduling.

## A. Real-Time Price Volatility

Substantial volatility in real-time energy markets is expected because system demands can change rapidly, and supply flexibility is restricted by physical generator limitations and network constraints. The day-ahead market operates on a longer time horizon with more commitment options and additional liquidity provided by virtual transactions. Because real-time flexibility is limited, the system is frequently "ramp-constrained" (i.e., units unable to move quickly enough to achieve their optimal output). This results in transitory price spikes. Figure 18 compares 15-minute price volatility at various locations in MISO and in three neighboring RTOs.

**Figure 18: Fifteen-Minute Real-Time Price Volatility in 2020**



The results in Figure 18 show that volatility in 2020 was similar at most locations to 2019. MISO generally experienced price volatility comparable to PJM and NYISO (apart from NYISO West) in 2020. Only the price volatility in ISO New England was lower than in MISO, generally because it experiences much less congestion than each of the other RTOs.

Volatility in MISO primarily occurs when ramp constraints bind and cause sharp price movements, which tends to happen when:

- Actual load is changing rapidly, including non-conforming load associated with industrial facilities that can change sharply and without advance notice;
- Net Scheduled Interchange (NSI) changes significantly;
- Wind output changes sharply; or
- The load-offset parameter (used to manage control-area performance) is not set optimally to manage anticipated ramp changes.

MISO has made significant efforts to improve the commitment, dispatch, and pricing of units in recent years. MISO implemented a "Ramp Capability" product in the spring of 2016 to hold additional ramp capability when the projected benefits exceed its cost. This product has improved MISO's management of the system's ramp demands and mitigated its price volatility. Additionally, MISO is planning to automate "offsets" completely by 2022, and we expect this will dampen the price volatility caused by operator offset selections.

## B. Fast-Start Pricing in ELMP

MISO implemented the Extended Locational Marginal Pricing algorithm in March 2015 and has made several incremental improvements since then. In May 2017, MISO expanded the set of resources eligible to set prices,[23] and in November 2019, MISO further expanded ELMP to allow Fast-Start Resources[24] (FSR) committed in the day-ahead market to participate in real-time price setting. In December 2020, MISO filed Tariff changes in response to our recommendation to remove ramp restrictions for FSRs that are operating at their dispatch minimum.

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 FSRs and emergency resources to set prices when they are:

- *Online* and deemed economic and needed to satisfy the system's needs; or
- *Offline* and deemed economic during transmission or energy shortage conditions.

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23 Prior to May 2017, the only online units eligible to set prices in ELMP were those that: a) could start in 10 minutes or less, b) had a minimum runtime of one hour or less, and c) were not scheduled in the day-ahead market. Phase II extended participation to include resources with up to a one-hour start up time.

24 Fast-Start Resource is a term defined in the MISO Energy Markets Tariff as a resource that can provide its output within 60 minutes and has a minimum run time of one hour or less.

The online resource component of these reforms was intended to remedy issues that caused real-time prices in some periods to be substantially understated. This led to increased RSG costs and poor pricing incentives to schedule generation and interchange. Although they may not appear to be marginal in the five-minute dispatch, the ELMP model recognizes that peaking resources are marginal and should set prices to the extent they are needed to satisfy the system's needs.

The second reform allows offline fast-start resources to participate in setting prices under transmission and reserve shortage conditions. In theory, it is efficient for offline resources to affect prices only when: a) they are feasible (can be started quickly to address the shortage) and b) they are economic for addressing the shortage. However, when units that are neither feasible nor economic to start are allowed to affect energy prices, the resulting prices will be inefficiently low. For several years, we have recommended that MISO suspend offline ELMP. MISO plans to limit offline ELMP participation to resources recommended for commitment in the Look-Ahead Commitment model. This change addresses our recommendation by helping restrict ELMP participation to economic and feasible offline resources.

In 2020, ELMP had a modest effect on MISO energy prices, increasing the average real-time prices by $0.70 per MWh, up from $0.33 per MWh in 2019. The largest ELMP impacts occurred in July, when the average increase was $3.43 per MWh. ELMP had larger effects at certain congestion locations—the average effects ranged from -$1.29 to $6.40 per MWh at the most affected locations each month. As expected, ELMP had almost no effect in the day-ahead market because the overall supply is much more flexible and includes virtual transactions.

#### *Evaluation of Online Pricing of Fast-Start Resources*

Our prior evaluations concluded that the relatively small effects of the online pricing occurred because a very small share of MISO's resources were initially eligible to set prices. This was expanded somewhat when MISO implemented ELMP Phase II in May 2017 and ELMP Phase III in November 2019. Currently, ELMP does not allow resources to set prices when the dispatch model seeks to ramp them down at their maximum ramp rate. However, MISO's December 2020 Tariff filing[25] will relax the down ramp rate limit on FSRs dispatched at their economic minimums so they can be considered marginal and set prices unless dispatched to zero.

In Table 4 below, we compare the average expected price increase in 2020 based on the current configuration of ELMP to the expected impacts from removing the ramp limitations. For both scenarios, we re-cleared the market from the ex-ante case solution in order to ensure comparability of the results. This heuristic approach explains why the current ELMP average price increase differs from the load-weighted average metric detailed above. The results below include the expected average price increase, the percentage of resources that would be eligible to participate, and the percentage of intervals affected by ELMP.

[25] Docket ER21-700-000

**Table 4: Evaluation of ELMP Online Pricing**

| Alternative ELMP Methods | Avg. Price Increase ($/MWh) | % of Fast-Start Peaker Eligible | % of Intervals Affected |
|---|---|---|---|
| Current ELMP Units | $0.41 | 40.0% | 17.2% |
| No Ramp Limitation | $0.89 | 67.9% | 29.6% |

Based on the current configuration, we estimate that ELMP only increased real-time prices by $0.41 per MWh in 2020, compared to an $0.89 per MWh expected impact that would have occurred had MISO already eliminated the ramp rate restrictions. Relaxing the downward ramp limitation on the peaking resources would have more than doubled the effectiveness of ELMP in allowing LMPs to reflect the costs of peaking resources needed to satisfy the system's demands. These more efficient prices will have large beneficial effects on high-load days, improving the commitment of resources and the scheduling of imports and exports.

#### *Emergency Pricing with the ELMP Model*

MISO's December 2020 Tariff filing addressed our recommendations to improve MISO's pricing during emergencies.[26] MISO's emergency pricing establishes an emergency offer floor price that is applied to all emergency resources and MWs in the ELMP model. In previous years, MISO's emergency offer floor prices ranged from $119 per MWh to nearly $700 per MWh, which is generally inefficiently low. MISO's filing will expand the set of resources that can set the price during an emergency event and established minimums on the Tier 1 and Tier 2 Emergency Offer Floor Prices at $500 per MWh and $1,000 per MWh, respectively. This will help ensure that MISO's emergency pricing will set more efficient pricing during emergencies.

### C. Uplift Costs

Uplift costs are very important because they are costs that are difficult for customers to forecast and hedge, and they generally reveal areas where the market prices do not fully capture the system's requirements. Most uplift costs are the result of guarantee payments made to participants. MISO employs two primary forms of guarantee payments in real time to ensure resources cover their as-offered costs and, therefore, have 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.
- 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 receive a day-ahead RSG payment as needed to recover their as-offered costs. Resources committed by MISO after the day-ahead

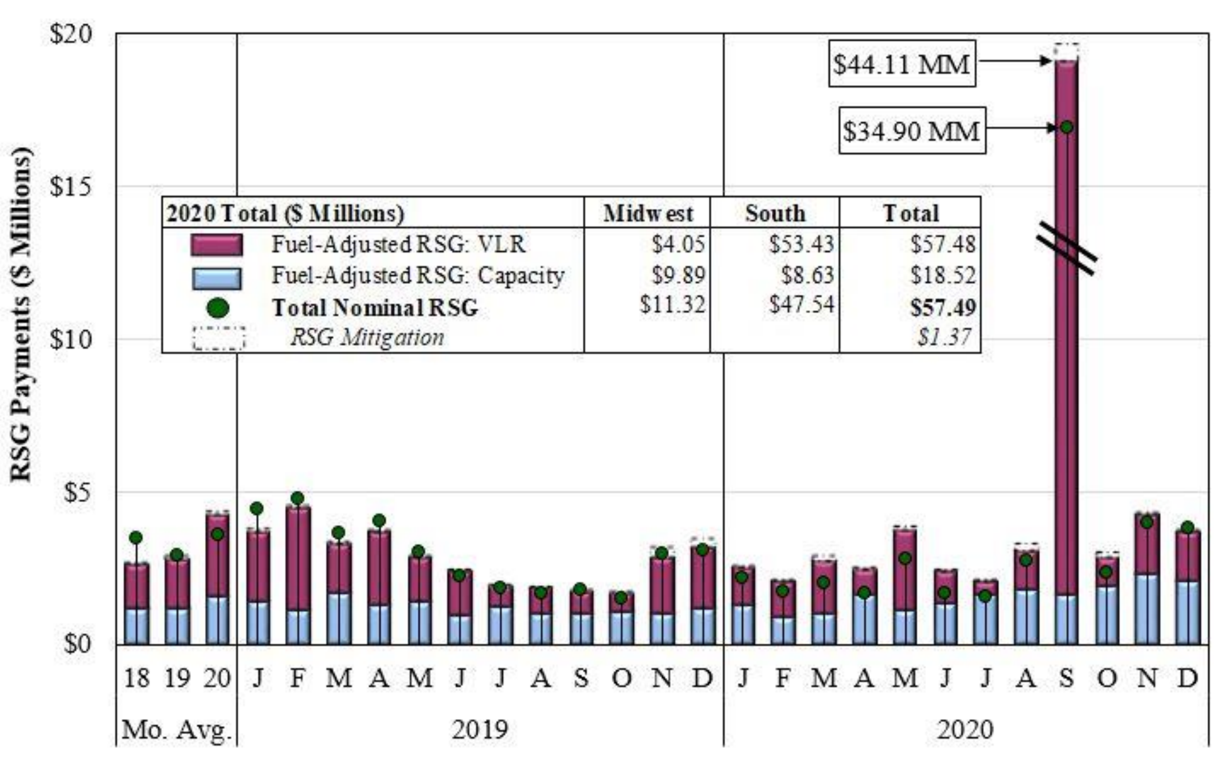
26 Id.

market receive a real-time RSG payment as needed to ensure they 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 participant actions that cause the costs, and the residual is charged to load. This allocation generates efficient incentives for participants.

### *Day-Ahead and Real-Time RSG Costs*

Figure 19 shows monthly day-ahead RSG payments by the underlying cause of the RSG. 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. Because fuel prices have considerable influence over suppliers' production costs, the figures show RSG payments in both nominal and fuel-adjusted terms.[27] The maroon bars show the RSG paid to units started for VLR before the day-ahead market.

**Figure 19: Day-Ahead RSG Payments**
2019–2020




Nominal day-ahead RSG rose 71 percent, but it increased by more than 125 percent on a fuel-adjusted basis day-ahead. This increase was largely driven by conditions that arose following Hurricane Laura in the South in August. In September, very high day-ahead RSG was incurred

27 Fuel-adjusted RSG payments are indexed to the average three-year fuel price of each unit. Downward adjustments are, therefore, greatest for periods when fuel prices were highest and vice versa.

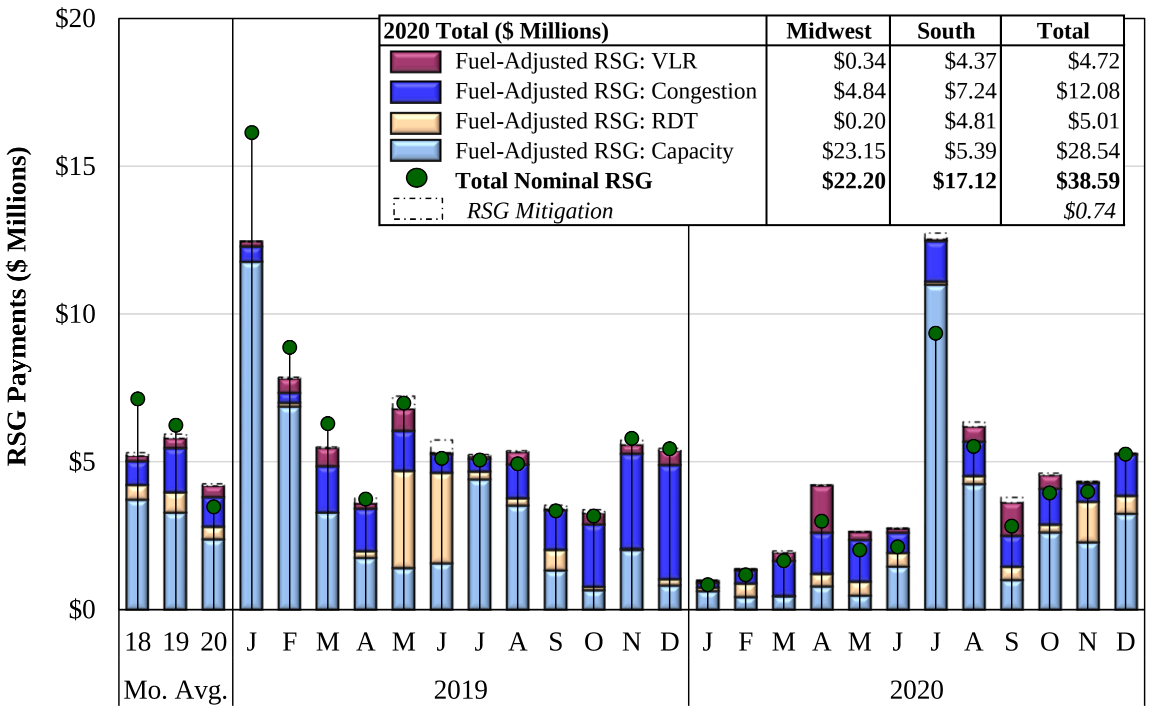
as units with high risk-related costs committed in East Texas in the newly formed Hurricane Laura Load Pocket received over $30 million in RSG payments. These units' offers reflected a significant risk of outage. This risk manifested when two units tripped after a few days online.

Almost all the 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 reduced the need for VLR commitments in that region. Excluding the significant VLR costs in the South in September to support the Hurricane Laura Load Pocket, average monthly fuel-adjusted VLR costs fell by almost 30 percent in 2020.

Figure 20 shows the comparable monthly RSG payments from the real-time market. This figure shows the same categories of RSG, although it also includes two categories of RSG that do not appear in the day-ahead RSG figure:

- Transmission congestion-related RSG associated with units committed after the day-ahead market to manage flows on a constraint; and
- RDT-related RSG associated with units committed after the day-ahead market to manage flows on the RDT or to create regional reserves (headroom) to be able to respond reliably to the largest contingency in the region without overloading the RDT.

**Figure 20: Real-Time RSG Payments**
2019–2020




This figure shows that nominal real-time RSG payments fell 48 percent in 2020 and by 44 percent adjusting for changes in fuel prices. The decrease in fuel-adjusted RSG costs were the result of a much lower need to commit resources to satisfy capacity requirements in January and

February as MISO did not experience emergencies in these months as it did in 2019. MISO also committed fewer resources to satisfy subregional capacity needs and manage the RDT flows. These changes were offset by high RSG incurred to satisfy capacity needs during the unusually hot conditions in July. Between July 1 and 10, MISO incurred over $6 million in RSG. Figure 21 shows the timeframes and locations of these commitments. The red diamonds show the RSG that would have been owed had resources offered at their reference costs.

**Figure 21: Uplift by Commitment Type**
July 1–10, 2020

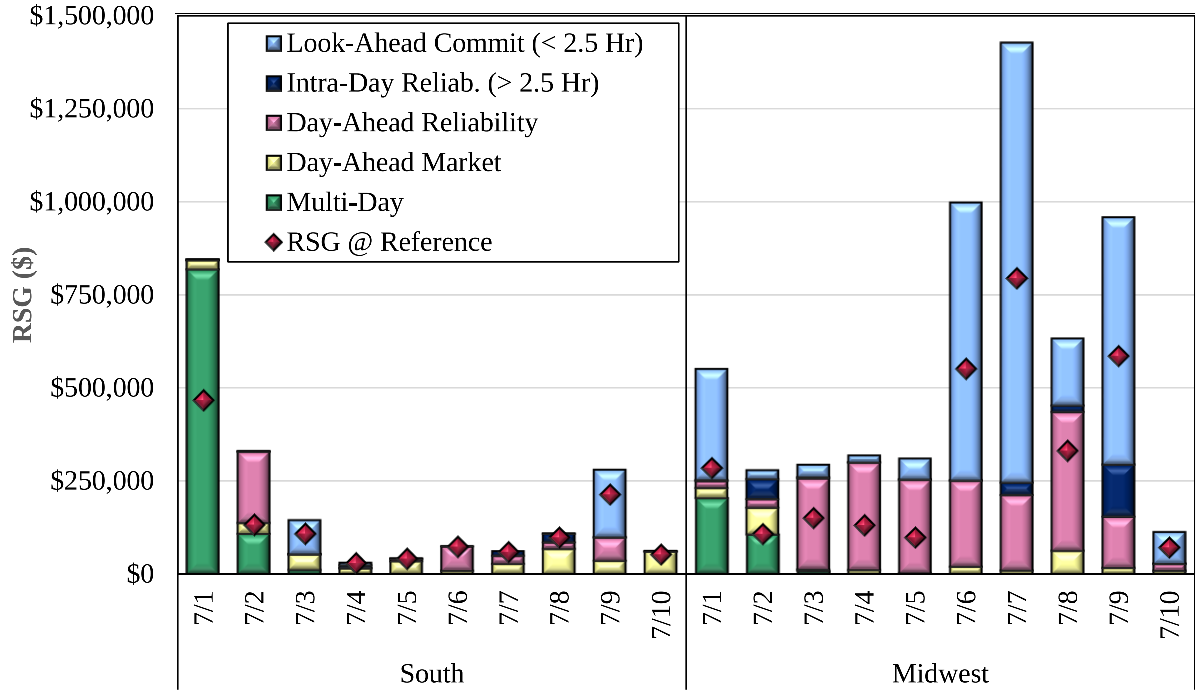



Figure 21 shows that MISO paid long-lead time units started in the South on July 1 roughly $800,000 (the green bars). During the peak hours, an average of 1,700 MW of this capacity was trapped in the South because of the RDT interface limit. The costs of these commitments equate to an implied Value of Lost Load of $40,000 per MWh, much higher than our recommended VOLL of $23,000. Additionally, of the more than $6 million in RSG during this period, roughly $1.3 million was incurred on July 7 when MISO declared a Maximum Generation Event (Step 1a). The emergency declaration led MISO to commit all available resources.

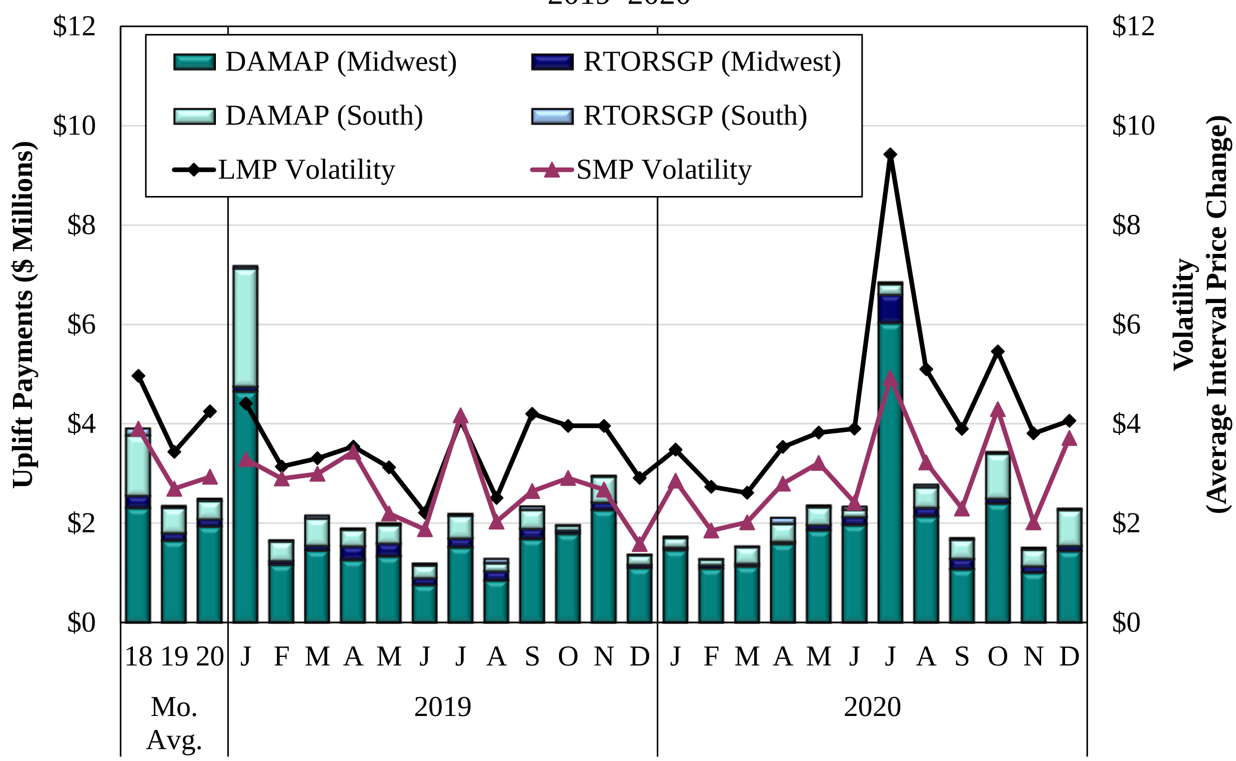
*Market Improvements that will Reduce RSG.* We previously recommended that MISO implement a regional 30-minute reserve product (short-term reserves or "STR") to allow the markets to procure the resources needed to satisfy these regional and VLR requirements that generate substantial day-ahead RSG costs. The STR product is scheduled for implementation in December 2021. We are currently working with MISO to develop appropriate demand curves to price shortages of short-term reserves consistent with sound economic principles.

Before STR could be implemented, MISO applied the Reserve Procurement Enhancement (RPE) to the RDT in August 2018 to satisfy the regional requirements with the 10-minute reserve capability. Additionally, to provide better pricing signals in the HLLP that was formed after Hurricane Laura occurred in August, MISO established a reserve zone and utilized the RPE into that area to set price that reflected the local reliability needs. These actions allowed MISO's market commitments to better satisfy the needs in those subregions. In the longer term, pricing these local reserve requirements with the STR product will provide efficient incentives for participants to invest in fast-starting generation that is well-suited to satisfy the requirements.

### *Price Volatility Make-Whole Payments*

PVMWPs address the concerns that resources can be harmed when 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. Figure 22 shows the monthly 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).

**Figure 22: Price Volatility Make-Whole Payments**
2019–2020



The highest DAMAP in 2020 occurred in July when emergency events and associated pricing resulted in DAMAP in the Midwest that exceeded $6 million. The figure shows that the overall PVMWP levels increased by 6 percent in 2020. While LMP volatility rose 24 percent in 2020 compared to 2019, this was partially offset by lower fuel prices that fell by 22 percent.

In prior *State of the Market Reports*, we expressed concerns that a large share of the DAMAP had been paid to units running at uneconomic output levels because they were not following dispatch instructions or because State Estimator model errors caused MISO to issue dispatch instructions that were less than optimal at some locations. MISO’s May 2019 changes to the UD threshold and PVMWP settlements were responsive to our prior IMM recommendations and has resulted in a significant decrease in unjustified DAMAP payments in the past two years.

## D. Regional Directional Transfer Flows and Regional Reliability

Since the integration of the South into MISO, the transfers between the South and Midwest have been constrained to adhere 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 305 MW below its contractual limit. During July, the RDT bound frequently in the South to North direction because much of the Midwest experienced higher than normal temperatures. In other months, the flows across the RDT were frequently correlated with wind output. Currently, all wind resources in MISO are in the Midwest Region so when MISO experiences high wind, the RDT flows tend to be in the North to South direction. Conversely, when wind falls sharply, flows tend to reverse to be in 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 had recommended that MISO introduce a 30-minute reserve product for each region. MISO filed the Short-Term Reserve product in October 2019, and FERC approved the filing in January 2020. Implementation is scheduled for December 2021.

Importantly, limiting interregional transfers that do not contribute to congestion on the SPP or the Joint Parties’ systems is inefficient. To reduce the inefficient costs in managing the transfers with the RDT, we recommend that MISO allow SPP and the Joint Parties to sell operating reserves using the capability on the RDT above its limit. MISO would then compensate SPP and the Joint Parties by paying them the clearing price for subregional reserves, which will be $500 per MWh (the RDT demand curve level) when the reserves are deployed.

## E. Generator Dispatch Performance

MISO issues energy dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. The performance of MISO's generators is essential to efficiently managing congestion and maintaining reliability in MISO. Therefore, it is very important that MISO's markets provide adequate incentives for its generators to perform well in following MISO's dispatch instructions. We evaluate and discuss generator performance in this subsection.

MISO had previously assessed penalties for deviations from this instruction when deviations remained outside of an eight percent tolerance band for four or more consecutive five-minute intervals within an hour. In May 2019, MISO altered the uninstructed deviation (UD) threshold calculations from an output-based tolerance to a tolerance that is a function of the offered ramp rate. The purpose of the tolerance threshold is to permit deviations to balance the physical limitations of generators with MISO's need for units to follow dispatch instructions. This was in response to recommendations that we made in previous *State of the Market Reports* for MISO to:

- Improve the tolerance bands for UD (i.e., deficient energy and excessive energy) to better identify units that are not following dispatch; and
- Modify the PVMWP rules to adjust the payment based on the generators' performance.

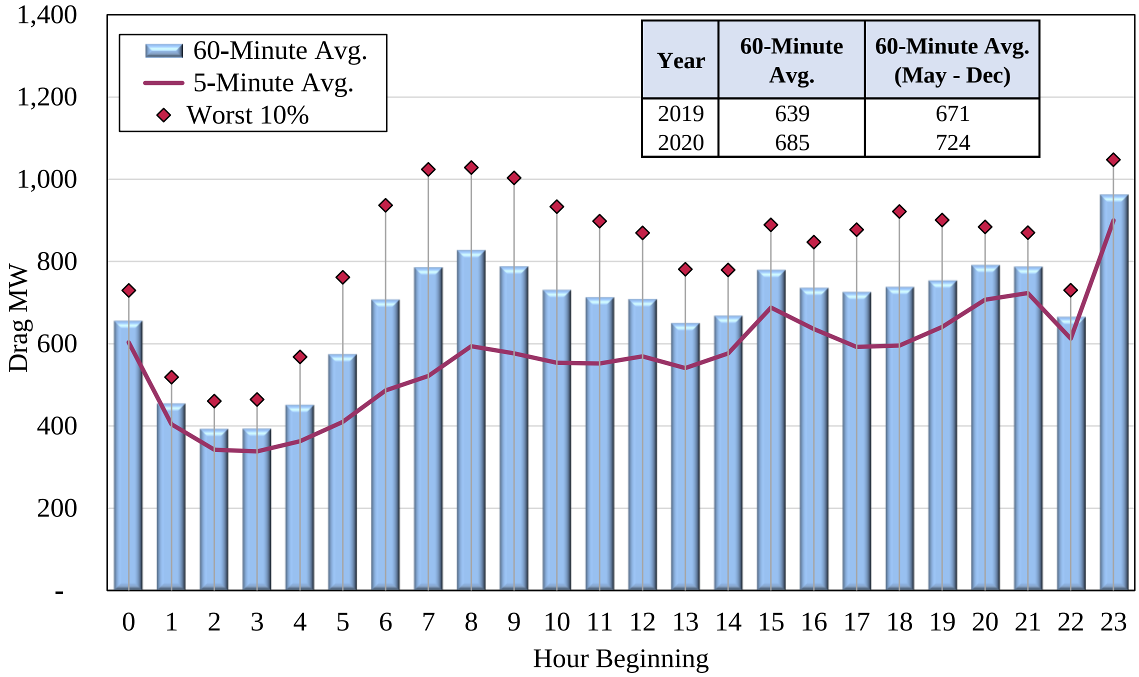
Additionally, MISO implemented a procedure in early 2018 to receive real-time alerts from the IMM that identify resources that are not following dispatch. This allows MISO to contact the generator and place it off-control when warranted. We are continuing to work with MISO to develop improved internal procedures to detect unreported derates or operational issues not reflected in resource offers, and to facilitate timely offer updates by market participants.

Together, these changes have significantly improved the performance of MISO's generators. We summarize this performance in Figure 23. This figure shows the average sixty-minute and five-minute average hourly dragging in 2020. The blue bars represent the average 60-minute dragging, and the red line represents the five-minute average dragging. The diamonds represent the worst 10 percent of dragging for each hour. The inset table indicates the average hourly dragging values in 2019 and 2020.

Figure 23 shows the average 60-minute dragging amount is highest in the morning ramp-up hours and during the evening ramp-down period. Dragging is high in the morning ramp hours because generators are asked to ramp up consistently as load rises. Dragging is high in the evening hours because online generators are asked to ramp up as other generators are going offline or as load is rising during the evening peak in the winter season.

The figure shows that the 60-minute dragging rose 7 percent in 2020, and it continues to raise substantial concerns because much of this capacity is effectively unavailable to MISO since the resources are not following the dispatch instructions. Almost 20 percent of the 60-minute deviations are scheduled in MISO's look-ahead commitment model. This is troubling because it indicates that MISO is not perceiving this effective loss of capacity and, therefore, may not be making commitments that are economic or needed for reliability.

**Figure 23: Average Five-Minute and Sixty-Minute Net Dragging**
2019–2020




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.

These findings indicate the importance of continuing to seek means to improve:

- Generator performance in following dispatch instructions; and
- The timeliness of suppliers' updates to their real-time offers, which should indicate their resources' true capabilities.

***Emergency Resources***

Emergency resources consist mainly of LMRs, Emergency Demand Response (EDRs), and internal generators that are only available during a declared emergency (Available Maximum Emergency or "AME"). While not required to submit economic offers, LMRs must submit their availability to the Market Communication System (MCS), an availability which may be substantially less than the quantity of capacity they cleared in the PRA. This becomes the basis for deployment during emergencies.

In recent years, MISO has made several Tariff changes requiring LMRs to provide shorter lead times and more availability throughout the year. MISO may now schedule LMRs in anticipation of an emergency event to access longer-lead resources, but curtailment is still only required if the emergency event is actually declared two hours prior to their scheduled deployment. In May 2020, MISO filed Tariff changes that would fully accredit LMRs with registered lead times under 6 hours and that provide curtailments at least ten times per year, beginning in the 2022–2023 Planning Year. Longer notification times and fewer maximum curtailments now need to be justified by the owner and such LMRs will receive lower accreditation values. This change increased the quantity of LMRs accessible within 2 hours from 39 percent to 62 percent.

Despite these improvements, we remain concerned that emergency resources are not comparable to other resources in satisfying MISO's reliability needs. Table 5 below quantifies the amount of LMRs and other emergency-only generation that was available based on when the emergency was called and offered notification times of each of the resources.

**Table 5: Availability of Emergency Resources during Events**
2018–2020

| Event | Lead Time to Event | Available Response (MW) | | |
|---|---|---|---|---|
| | | LMR-DR* | LMR-BTMG | AME |
| January 17, 2018 | 1.5 - 2 Hours | 1,033.2 | 939.1 | 1,648.8 |
| September 15, 2018 | Less than 15 Minutes | 439.4 | 871.7 | 143.0 |
| January 30, 2019 | 1 - 1.5 Hours | 1,698.8 | 934.8 | 521.0 |
| May 16, 2019 | | | | |
| Advance Schedule ** | 12 + Hours | 3,681.2 | 2,059.9 | N/A |
| Second Emergency | Less than 15 Minutes | 168.8 | 471.0 | 80.0 |
| May 17, 2019 ** | 12 + Hours | 3,702.1 | 2,043.4 | N/A |
| July 7, 2020 | 0.5 - 1 Hour | 1,379.2 | 1,534.9 | 183.3 |
| August 27, 2020 | Less than 15 Minutes | 284.4 | 1,366.4 | 132.0 |
| **Total Cleared Capacity in 2020/21 PRA** | | **7,557.4** | **4,334.3** | ***** |

* Includes LMRs that are offered or self-scheduled in DRR and EDR markets.

** Pre-Scheduled LMRs were cancelled in advance of event, no response required. Pre-scheduling of LMRs in advance of emergency declarations began after February 19, 2019, FERC Docket No. ER19-650-000

*** AME Resources are typically not designated as such in the capacity markets because they are only AME some of the time

Table 5 shows that the lead times vary significantly, and that MISO frequently declares emergencies less than 15 minutes prior to the beginning of the emergencies when conditions are generally the tightest. These short lead times are not surprising because emergencies tend to occur when there are multiple concurrent contingencies and/or higher than expected load that is not foreseen far in advance. For this reason, emergency resources with longer notification times provide much less value in most emergency events.

Examples of this diminished value occurred during both emergencies declared in 2020:

- During the August 27 event only 14 percent of LMRs and 11 percent of offered AME resources were available to help resolve the emergency.
- MISO was only able to access 3 GW of emergency-only resources during the July 7 event, including just 25 percent of the LMR resources that had cleared for capacity.

Even with the improvements described above, MISO's access to emergency-only resources remains a concern given MISO's reliance on them to meet its resource adequacy needs. For example, AME resources are only available after an EEA 1 has been declared and some AMEs have long notification times that prevent MISO from utilizing them. We recommend MISO modify the Emergency Operating Procedures to obtain access to longer-lead time AME in advance of anticipated emergencies, similar to the access to LMRs. We also recommend that MISO combine EEA Steps 1a and 1b. This change would allow MISO operators to deploy AME resources economically along with emergency ranges of online resources in an emergency. We are also recommending improvements in the accreditation rules to improve the accreditation of AME resources to reflect the differences in reliability value they provide the system. These issues are discussed in Section VII.G.

#### *Dispatch Operations: Offset Parameter*

The offset parameter is a quantity chosen by the MISO real-time operators to adjust the load to be served by the UDS. A positive offset value is added to the short-term load forecast to increase the generation dispatched, while a negative offset decreases the load and the corresponding dispatched generation. 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 are associated with increased 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 that in the five percent of hours with the largest changes in offset values, prices were significantly affected. Changes in offset values greater than 600 MW correspond to SMP changes greater than $35 per MWh.

We monitor offset values because large changes, although infrequent, can sometimes contribute to price spikes or mute legitimate shortage pricing. In the second quarter of 2020, MISO deployed a tool that improves the offset determinations and additional improvements are scheduled to be incorporated in 2021.

## F. Wind Generation

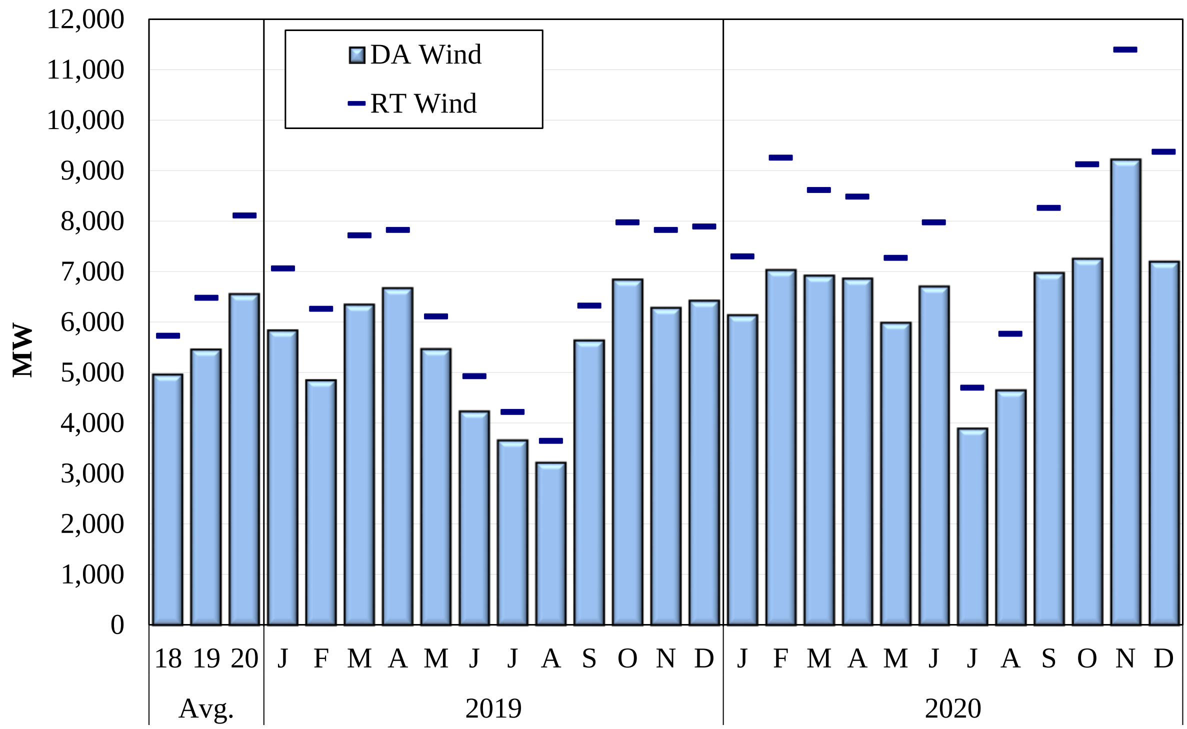
As discussed in Section III, wind capacity is continuing to grow in MISO. It now accounts for nearly 27 GW of MISO's installed capacity and produced 12 percent of all energy in MISO in 2020. Section III.A discusses the long-term challenges this will present and the market enhancements that we recommend. This subsection addresses near-term issues related to wind scheduling and forecasting.

### *Day-Ahead and Real-Time Wind Generation*

Figure 24 shows the average monthly wind output scheduled in the day-ahead market compared to the actual real-time wind output. This figure reveals the seasonal patterns of MISO's wind output, with output generally decreasing in summer months and at its highest levels in the spring and fall seasons. In 2020, average wind output was 25 percent higher than in 2019. Seven months in 2020 exhibited average wind output greater than 8 GW, compared to none in 2019. In November, average output exceeded 11 GW, the highest monthly average on record.

Figure 24 also shows that wind suppliers often schedule less output in the day-ahead market than they actually produce in real time. Underscheduling of wind averaged roughly 1,500 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-forecasted. Underscheduling can create price convergence issues and lead to uncertainty regarding the need to commit resources for reliability.

**Figure 24: Day-Ahead and Real-Time Wind Generation**
2019–2020



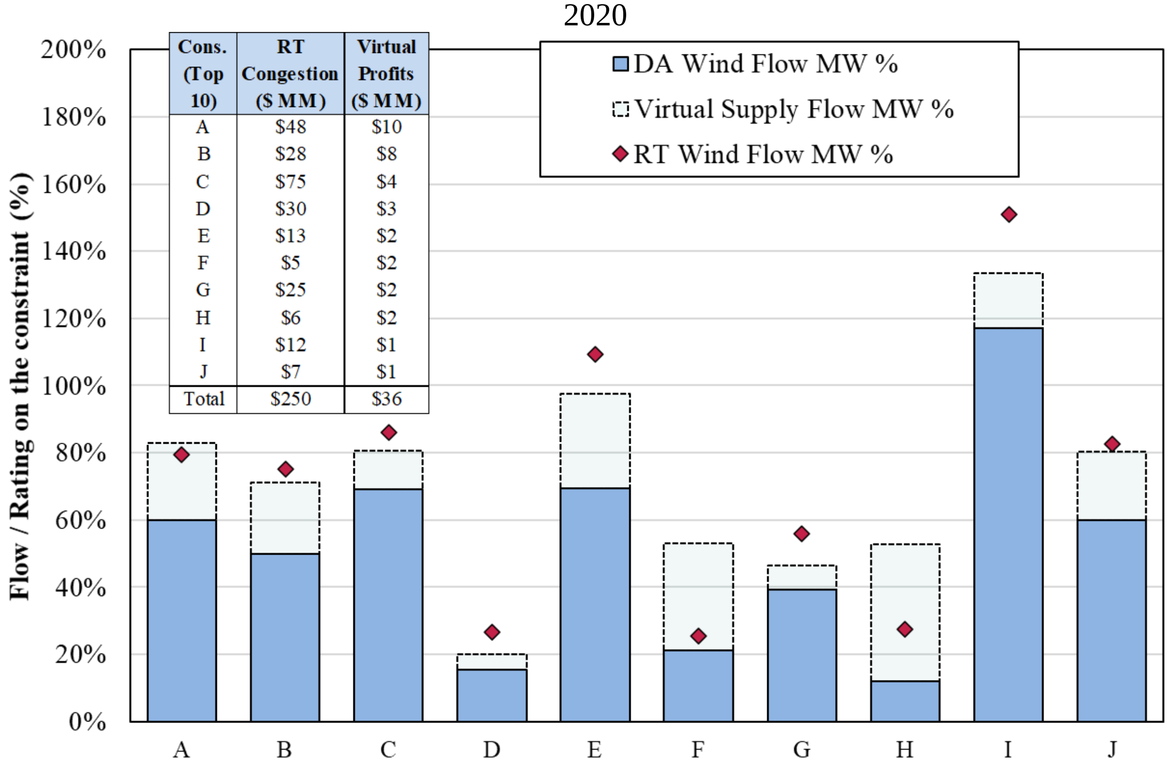
This convergence issue is partially addressed by net virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers. Since the most significant effect of underscheduling of wind in the day-ahead market is its effects on the transmission flows and associated congestion in the day-ahead and real-time markets, we evaluated the extent to which virtual transactions offset the flow effects of the wind underscheduling. In our analysis, 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 scheduling.

In Figure 25, 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. Since the majority of profits were realized on just 10 constraints, we limited the figure to the top 10 constraints and masked the constraint names.

Figure 25 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 $58 million on a total of 147 wind-impacted constraints, with more than 60 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.

**Figure 25: Top 10 Profitable Virtual-Impacted Wind-Related Constraints**

2020




| Cons. (Top 10) | RT Congestion ($ MM) | Virtual Profits ($ MM) |
|---|---|---|
| A | $48 | $10 |
| B | $28 | $8 |
| C | $75 | $4 |
| D | $30 | $3 |
| E | $13 | $2 |
| F | $5 | $2 |
| G | $25 | $2 |
| H | $6 | $2 |
| I | $12 | $1 |
| J | $7 | $1 |
| Total | $250 | $36 |

### *Wind Forecasting*

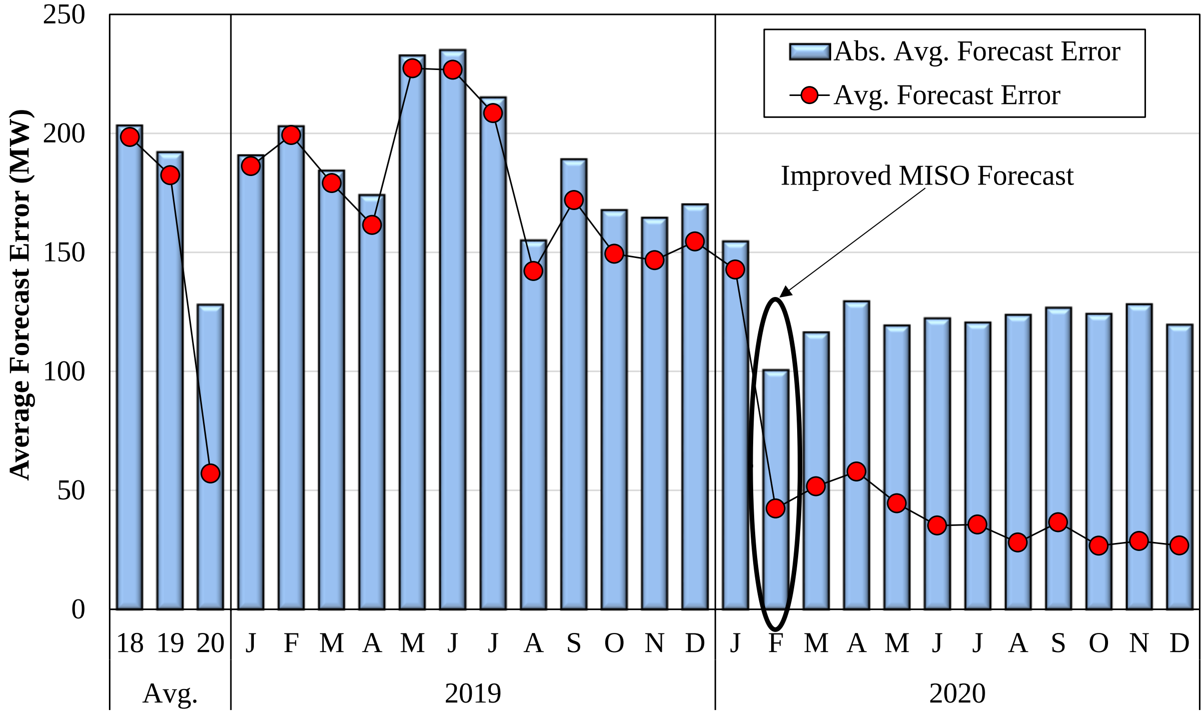
As intermittent wind generation grows, the importance of the near-term forecasts of wind output grows. The wind forecasts are important because MISO uses them to establish wind resources' economic maximum in the real-time market. Because wind units offer at prices lower than other units, the forecasted output also typically matches the dispatch instruction, absent congestion.

In 2017, we identified significant concerns with certain wind resources that frequently and substantially over-forecast their wind output in real time, and with the fact that wind resources in aggregate were over-forecasting their output most of the time. MISO implemented critical changes in May 2019 to its uninstructed deviation thresholds and PVMWP formulas that significantly improved its wind forecasting. The prior rules regarding uninstructed deviations created inefficient incentives for wind resources to over-forecast their output to avoid uninstructed deviations and associated penalties. These penalties potentially arise when a wind resource under-forecasts its output because it will generally receive a dispatch instruction matching its forecast. One of the key changes MISO implemented was to relieve wind resources of the uninstructed deviation penalties for resources that use the MISO wind forecast. This caused most wind resources to begin utilizing the MISO forecast beginning in May 2019.

Even though MISO's composite forecast was a significant improvement over the participant forecasts, we raised concerns that MISO's forecast was biased because it adopted the higher of: a) a resource's current output, and b) MISO's wind vendor forecast. This "higher of" methodology resulted in a biased forecast that distorted the MISO dispatch and its management of congestion. Hence, we recommended that MISO eliminate the higher of logic that was systematically over-forecasting the wind output. On February 3, 2020 MISO adopted this recommendation, eliminating the "higher-of" logic and adopting its vendor forecast exclusively. The impacts of this change are shown in Figure 26, which shows the average forecast error and averager absolute value of the forecast error monthly over the past two years.

The elimination of the "higher-of" forecast logic substantially reduced the persistent over-forecast bias and reduced the absolute wind forecasting error, particularly in periods when wind output is falling. As shown in the figure above, the average forecast error dropped 66 percent from 2019 to 2020 as a result of MISO's improved forecast, while the absolute average forecast error fell 33 percent. This was an excellent first step, and we encourage MISO to evaluate changes that could further improve its forecast accuracy.

**Figure 26: Average and Absolute Average Wind Forecasting Errors in MISO**
2019–2020




Lastly, we are concerned that MISO allows wind resources to provide its ramp product. We recommend that MISO disqualify wind resources from providing the ramp product. Wind resources clear ramp capability only in the up direction when curtailed for congestion management. Deploying this capacity as energy in subsequent periods would contribute to reliability problems by overloading constraints and negating any benefit in meeting the market-wide generation demand.

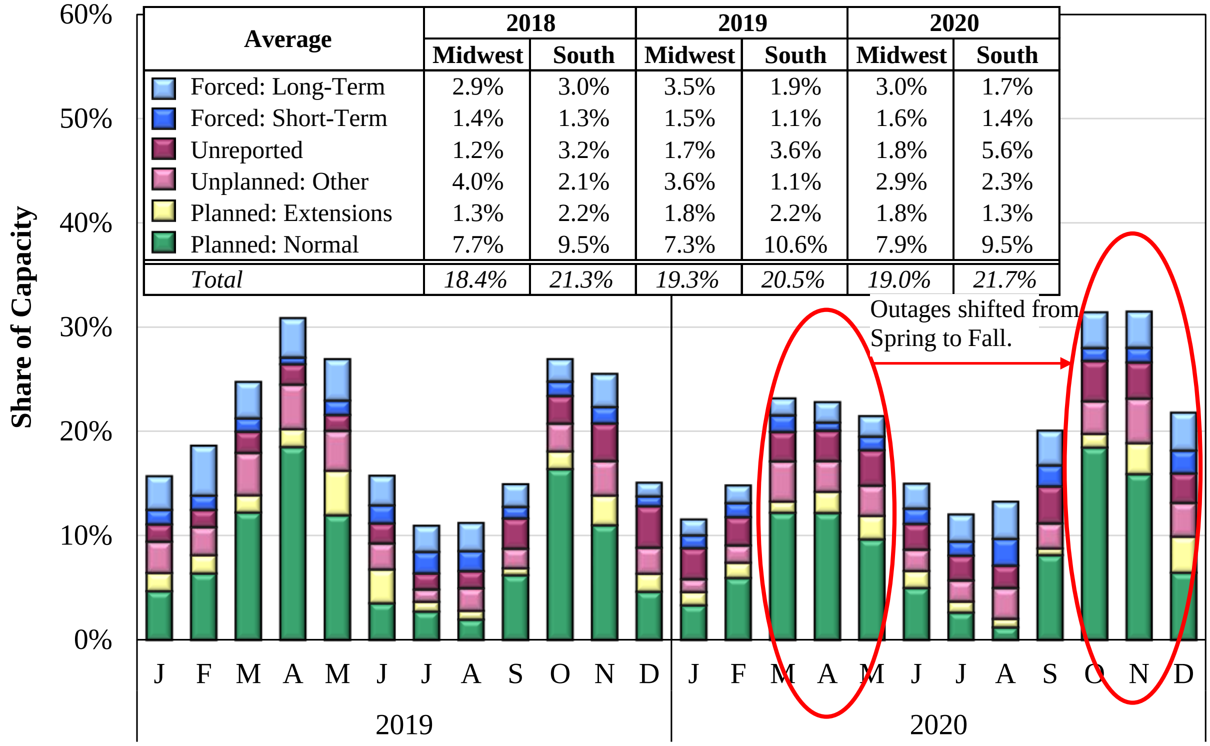
## G. Outage Scheduling

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 2020, Figure 27 shows MISO's available capacity, outages, peak load, and emergency conditions in MISO Midwest and MISO South.

Figure 27 shows that outage rates in 2020 were comparable to 2019. During the spring, more than 20 GW of planned outages were postponed or cancelled because of COVID issues. Approximately 2 to 3 GW of those planned outages were moved to the fall. As in prior years, true planned outages were low for most of the summer.

**Figure 27: MISO Outages**

2019–2020




| Average | 2018 | | 2019 | | 2020 | |
|---|---|---|---|---|---|---|
| | Midwest | South | Midwest | South | Midwest | South |
| Forced: Long-Term | 2.9% | 3.0% | 3.5% | 1.9% | 3.0% | 1.7% |
| Forced: Short-Term | 1.4% | 1.3% | 1.5% | 1.1% | 1.6% | 1.4% |
| Unreported | 1.2% | 3.2% | 1.7% | 3.6% | 1.8% | 5.6% |
| Unplanned: Other | 4.0% | 2.1% | 3.6% | 1.1% | 2.9% | 2.3% |
| Planned: Extensions | 1.3% | 2.2% | 1.8% | 2.2% | 1.8% | 1.3% |
| Planned: Normal | 7.7% | 9.5% | 7.3% | 10.6% | 7.9% | 9.5% |
| *Total* | *18.4%* | *21.3%* | *19.3%* | *20.5%* | *19.0%* | *21.7%* |

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.

- Twice weekly, MISO posts the Maintenance Margin that contains historical actual outages and projected outages by date and region.
- In December 2019, MISO began posting a daily Multiday Operating Margin Forecast indicating the forecasted system capacity margin in the peak hour for the next six days.

In January 2020, FERC approved Tariff language that disqualifies resources from capacity market participation that are expected to be on outage for 90 of the first 120 days of the planning year. This change was implemented for the 2020–2021 PRA and led to material impacts on the capacity auction clearing price in Zone 7.

We have also recommended that MISO improve its capacity accreditation rules to improve suppliers' incentives to schedule outages efficiently and be available when needed. MISO has made some changes to its accreditation rules, but these changes had very limited effects. Hence, we continue to recommend more substantial accreditation changes that would provide stronger incentives for generators to better plan and coordinate outages and to make resources available during tight conditions (see Section III.C for more detail).

### H. Conclusions

The operation of MISO's real-time market and associated real-time pricing is essential for achieving both the reliability and economic benefits that MISO provides to the region. This section of the report evaluates a wide array of real-time pricing and operational issues. Overall, we conclude that the MISO markets operated well in 2020, but this section also identifies a number of key improvements listed below.

- *Improve Shortage Pricing*: Section III.B describes recommended changes to MISO's shortage pricing that would substantially improve generators' incentives to be available when needed and reward generators for flexibility. This will also improve longer-term incentives to invest in new resources when needed and to maintain existing resources.
- *Eliminate Offline ELMP Pricing:* For MISO's pricing of operating reserve shortages and transmission shortages to be accurate, it must address the inefficient pricing effects of its offline ELMP pricing. MISO has committed to changes that will address these concerns.
- *Engage Joint Parties in Managing Regional Emergencies*: The primary risk of regional capacity deficiencies is that MISO may exceed the RDT after a contingency occurs. When this would not cause significant reliability issues, the joint parties could sell operating reserves above the RDT limit and be compensated based on the regional short-term reserve prices. We recommend MISO pursue this with the Joint Parties.
- *Actively Coordinate Outages*: We have seen numerous cases where simultaneous generation and/or transmission outages in an electrical area have led to severe transmission congestion. We recommend that MISO explore alternatives to improve 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.

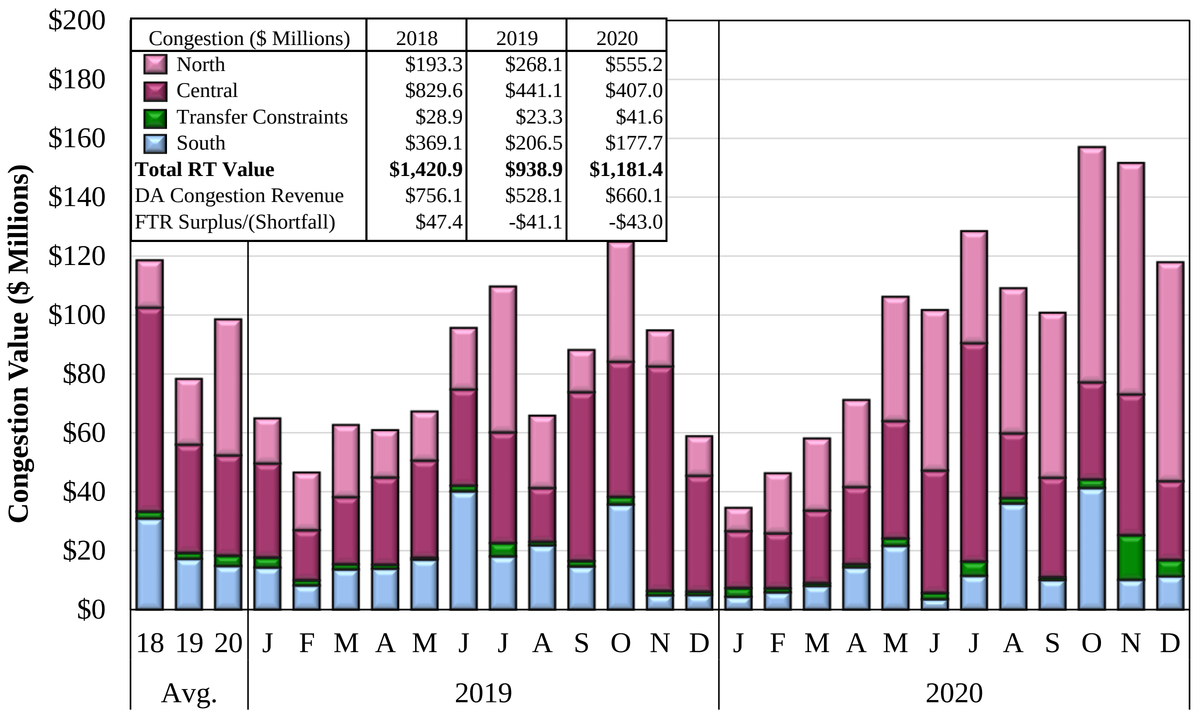
## VI. Transmission Congestion and FTR Markets

To avoid violating transmission constraints, MISO manages power flows over the network by adjusting resource dispatch levels and establishes efficient, locational prices representing 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 the three components of the LMPs. 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 congestion-related price signals are valuable not only because they induce changes in generation to efficiently manage network congestion, but also because they provide longer-term economic signals that facilitate efficient investment and maintenance of generation resources.

### A. Real-Time Value of Congestion in 2020

We calculate the value of real-time congestion by multiplying the physical flow over each constraint by the economic value of the constraint (i.e., the "shadow price", the production cost savings from increasing the constraint by one MW). This is the value of congestion that occurs as MISO dispatches its system. Figure 28 shows these results by month over the past two years.

**Figure 28: Value of Real-Time Congestion and Payments to FTRs**
2019–2020



The value of real-time congestion rose 26 percent relative to 2019, totaling $1.2 billion. Congestion in the South and Central Regions fell, but congestion in the North Region more than doubled as wind output increased substantially in 2020. Wind output was particularly high in the fall when wind resources set the price in 85 percent of constrained market intervals. More than half of the real-time congestion was related to wind. In addition to wind, multiple episodes of congestion contributed to the overall congestion increase in 2020:

- In May, a high-voltage transmission outage caused by a storm contributed to $13 million of congestion on one day in the South;
- During the summer, more than $45 million of the congestion increase was attributable to low generation availability in Michigan. MISO declared two transmission emergencies in Michigan that contributed to $35 million in congestion; and
- On August 27, Hurricane Laura impacted Eastern Texas and Western Louisiana. Impacted nodes were priced at VOLL to reflect the loss of firm load in the region, and this led to more than $90 million in balancing congestion.

Improved manageability offset some of the increase in congestion in 2020. 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 fell by $43 million in 2020. The figure also shows day-ahead congestion revenue and FTR accounting, which are discussed in detail in the next subsection.

We discuss several key issues below that continue to hinder congestion management in MISO, including:

- The use of very conservative ratings by most transmission operators;
- Procedural issues in defining, activating, and coordinating market-to-market constraints;
- Limitations of MISO's authority in outage coordination; and
- Congestion caused by TLR response on external constraints.

## B. Day-Ahead Congestion and FTR Funding

MISO's day-ahead energy market is designed to send accurate and transparent locational price signals that reflect energy costs, congestion, and losses on the network. MISO collects congestion revenue in the day-ahead market 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 (FTR), which are economic property rights to flow power over the transmission system.

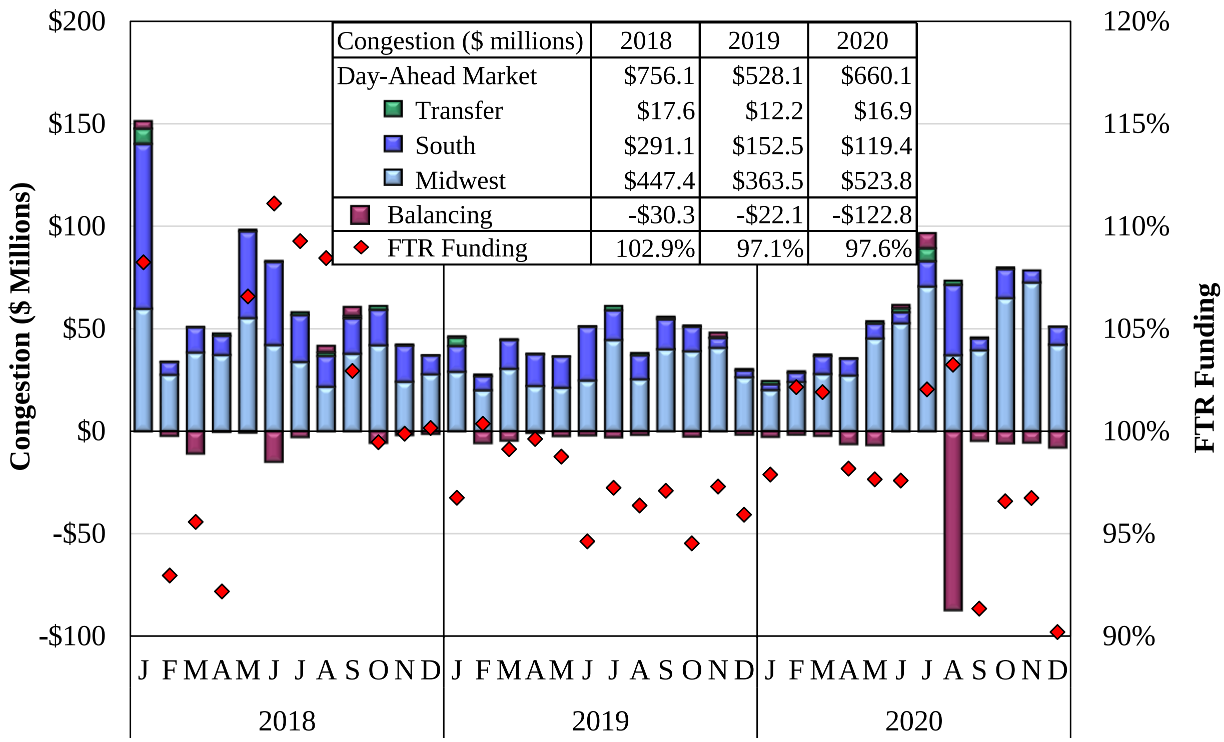
A large share of the value of these rights is allocated to participants based on historical firm use of the transmission network. Residual transmission capability is sold in the FTR markets, with this revenue contributing to the recovery of the costs of the network. FTRs provide a means for market participants 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 aspects of how 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 costs of doing so is uplifted to MISO customers as "balancing congestion".

Figure 29 summarizes the day-ahead congestion by region (and between regions), balancing congestion incurred in real time, and the FTR funding levels from 2018 to 2020.

**Figure 29: Day-Ahead and Balancing Congestion and FTR Funding**
2018–2020




*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 grew 24 percent to $660 million in 2020. The day-ahead congestion costs collected through the MISO markets were about 60 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 entitlements on the MISO system granted to SPP and PJM and other JOA parties that are not included in the day-ahead congestion settlement.

In early July, high temperatures in the Midwest contributed to high day-ahead congestion. MISO declared a Local Transmission Emergency on August 28 because of hurricane-related outages in Eastern Texas that led to more than $10 million in day-ahead congestion. In October and November, high wind and rescheduled outages from the spring due to COVID contributed to high congestion in the day-ahead market. FTRs were not fully funded in 2020 partly because of modelling differences between the FTR markets and the day-ahead markets, as described below.

### *FTR 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. In 2020, FTR obligations exceeded congestion revenues by $74.6 million—a shortfall of 4.1 percent before residual auction collections.

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 not to collect all the congestion revenue necessary to satisfy the FTR obligations. FTRs impacted by SPP constraints, for example, were underfunded by 50 percent in 2020.[28] 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 not to 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. This can cause funding levels to vary substantially by local balancing area (LBA).[29] The FTR obligations for transmission constraints in six LBAs were underfunded by 20 percent or more. 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.

28 Improvements to the GSF cutoff are discussed and recommended later in this subsection.

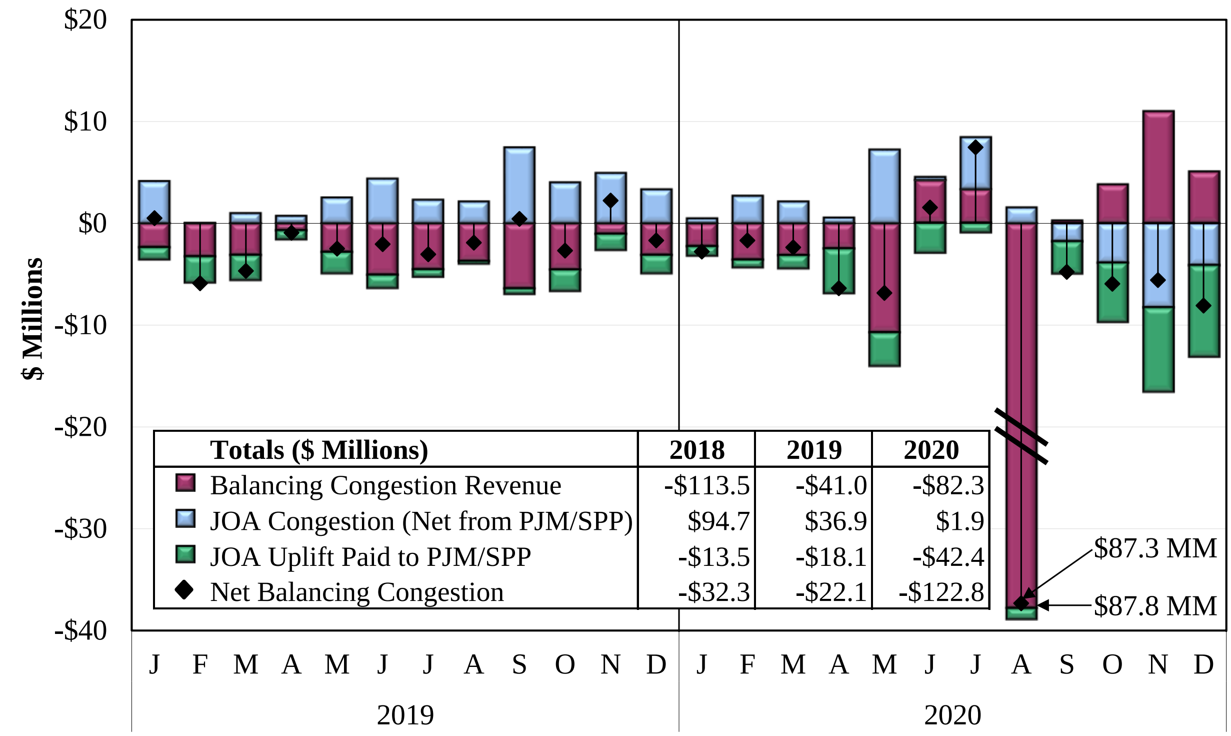
29 See Section VI.B in the Analytic Appendix.

### *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, the costs of re-dispatching generation to manage constraints in real time to reduce day-ahead scheduled flows are negative balancing congestion. Conversely, positive balancing congestion occurs when real-time constraints bind at flows higher than 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 30 shows the 2018 through 2020 monthly balancing congestion costs incurred by MISO.

**Figure 30: Balancing Congestion Costs**
2018–2020




Net balancing congestion grew by $100 million in 2020, including JOA uplift of $42 million. JOA uplift payments are made to pay for market flows that exceed entitlements on coordinated M2M constraints. Most of the increased balancing congestion accrued during the Hurricane

Laura load shedding event. For several hours on August 27, MISO priced the Hurricane Laura Load Pocket in east Texas at VOLL ($3,500 per MWh) during the period in which it directed firm load shed to stabilize the load pocket. Because transmission capability into the pocket was severely reduced in real time relative to the transmission flows scheduled in the day-ahead market, MISO incurred almost $90 million in balancing congestion to buy back the day-ahead scheduled flows at the real-time price of $3,500 per MWh. This was the correct and efficient outcome under these conditions, although these costs were unfortunately allocated to load throughout MISO. MISO should consider more equitable cost allocation rules for similar events in the future.

## C. Key Congestion Management Issues

Given that MISO generally experiences between $1 and $1.5 billion in real-time congestion each year, improvements aimed at the efficiency of its congestion management can deliver sizable savings. Some of these opportunities are discussed below in the subsection evaluating market-to-market coordination. This subsection identifies two key opportunities to improve the management of congestion more broadly.

### *Modifying GSF Cutoffs for Congestion Management*

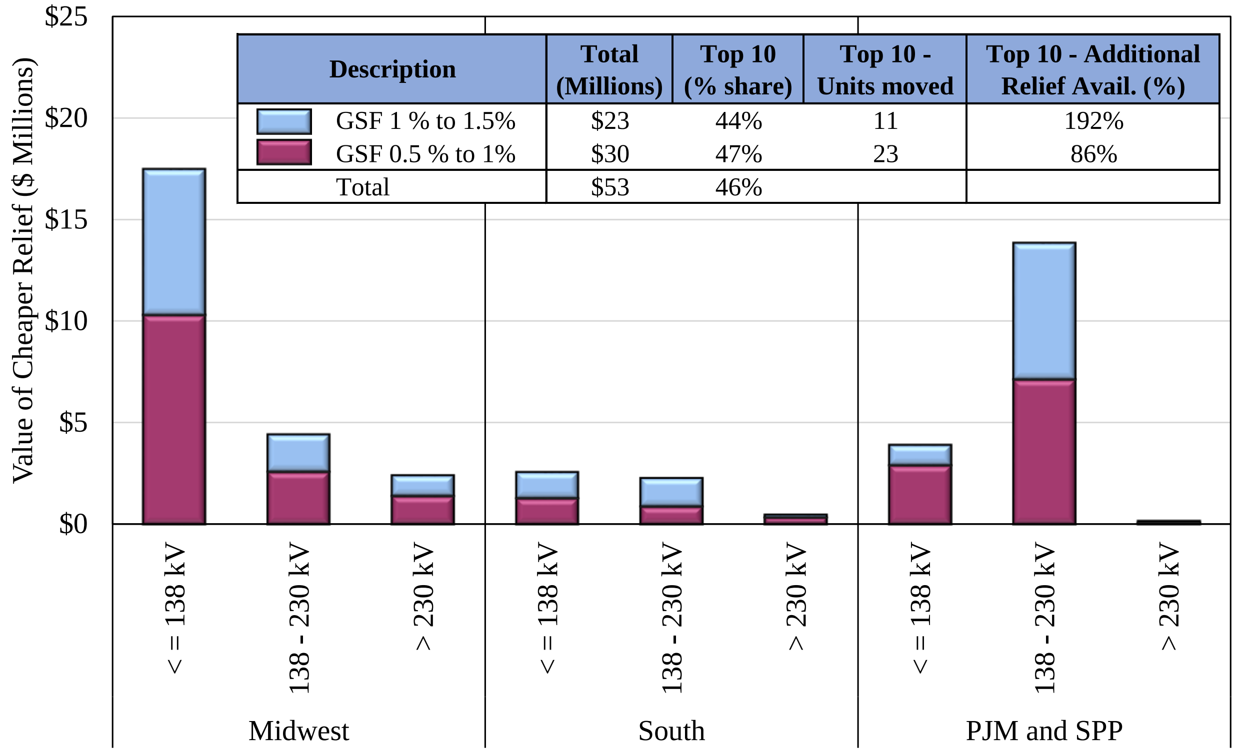
A generation shift factor (GSF) indicates how changes in net injections at a given node will impact flows on the constraint. We evaluate the economic benefits of modifying the GSF cutoff MISO uses in its market software. MISO employs a GSF cutoff of 1.5 percent so that electrically distant generators will not be re-dispatched to manage congestion. This reduces the complexity and solution time of MISO's market software.

Factoring performance implications into system design is a reasonable practice. However, the loss of congestion relief can adversely affect reliability, increase M2M settlements, and lead to FTR shortfalls. SPP and PJM both recognize these concerns and no longer apply a cutoff in their markets. While eliminating the cutoff entirely may be untenable, we evaluated the benefits of reducing the GSF cutoff down to 0.5 percent and believe this level would address our concerns.

In Figure 31, we show the economic value of the additional congestion relief that can be achieved by lowering the GSF cutoff, along with the portion of the benefits that can be achieved by lowering the cutoff on just ten constraints with the highest benefits.

This analysis shows $53 million of incremental economic relief would be available if the GSF cutoff were reduced to 0.5 percent. Most of the benefits were concentrated on a small number of low-voltage constraints and Market-to-Market (M2M) constraints. MISO could capture around half of the benefits if it implemented a 0.5 percent GSF cutoff for just ten constraints. This is key because it may not be feasible to reduce the cutoff on all constraints. Hence, we recommend MISO develop the capability to reduce the GSF cutoff on individual constraints.

**Figure 31: Value of Additional Available Relief**
2020




### *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 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 that 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 32 summarizes the effects of uncoordinated planned outages on congestion by showing the portion of the real-time congestion value incurred in 2019 and 2020 that occurred on internal constraints that were substantially affected (at least 10 percent of the constraints' flows) by two or more planned outages.

**Figure 32: Congestion Affected by Multiple Planned Generation Outages**
2019–2020

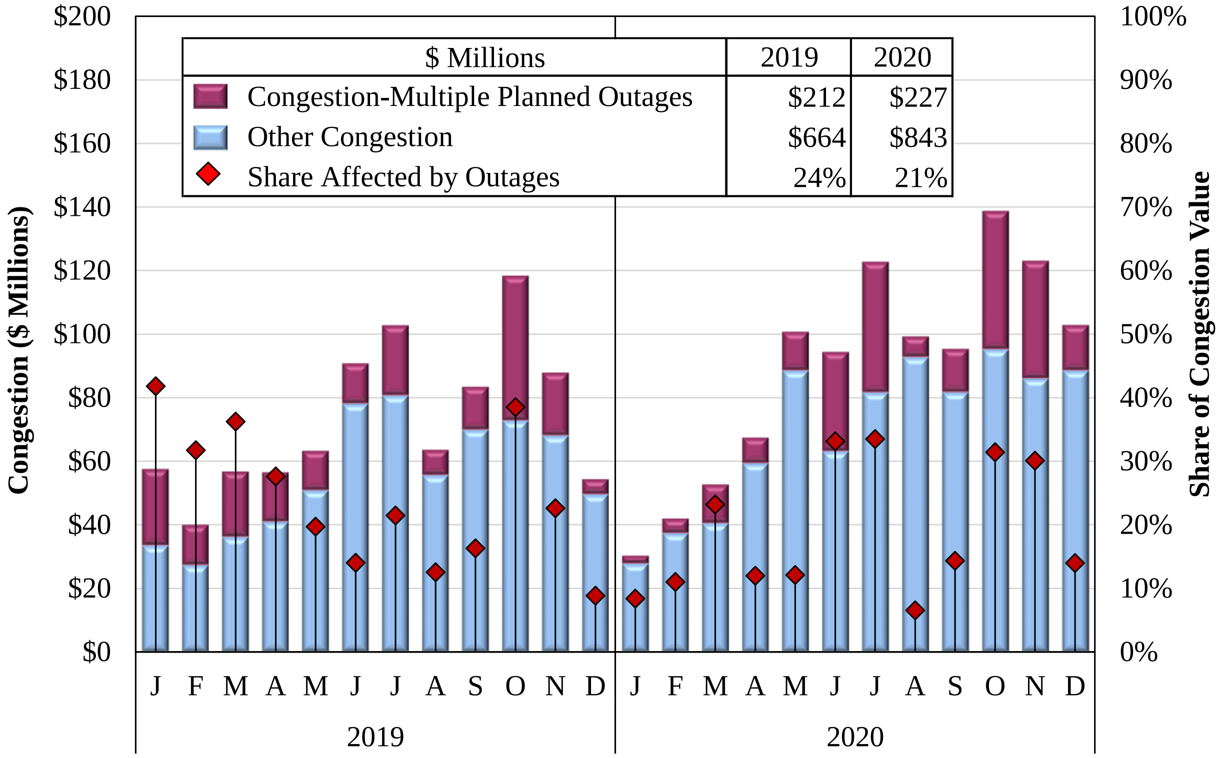



Figure 32 shows that 21 percent of the total real-time congestion on MISO's internal constraints in 2020 ($227 million) was attributable to multiple planned generation outages. In several months, planned outages caused significant congestion, including almost a third of all congestion in a number of months. Figure 32 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.

## D. 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.[30] Therefore, if transmission owners develop and submit ratings adjusted for

30 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 benefit from the absence of solar heating. Our analysis evaluates only ambient temperature impacts.

temperature or other relevant ambient conditions, they would allow MISO to operate to higher transmission limits and achieve substantial production costs savings. Most transmission owners 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, although the Commission has recently proposed to require TOs to provide AARs in its Notice of Proposed Rulemaking (Docket No. RM20-16), which we support.

Additionally, ratings for contingency constraints should be the emergency rating level (i.e., the flow level that the monitored facility could reliably accommodate temporarily (e.g., 2–4 hours) if the contingency occurs. After the contingency, the flow would rise to the emergency rating level. MISO would then enforce the normal rating and redispatch the system to bring the flow down. Many transmission owners do not provide MISO with both normal and emergency limits as called for under the Transmission Owner's Agreement, which substantially increases congestion as shown below.[31]

#### *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.[32] This analysis is described in detail in Section VI.E of the Analytic Appendix and summarized in Table 6.

**Table 6: Benefits of Ambient-Adjusted and Emergency Ratings**
2019–2020

| | | Savings ($ Millions) | | | # of Facilites for 2/3 of Savings | Share of Congestion |
|---|---|---|---|---|---|---|
| | | **Ambient Adj. Ratings** | **Emergency Ratings** | **Total** | | |
| **2019** | **Midwest** | $62.5 | $37.00 | $99.5 | 21 | 14.7% |
| | **South** | $4.0 | $11.12 | $15.1 | 3 | 7.6% |
| | **Total** | **$66.5** | **$48.1** | **$114.6** | **24** | **13.1%** |
| **2020** | **Midwest** | $57.0 | $43.07 | $100.1 | 18 | 10.8% |
| | **South** | $4.5 | $8.80 | $13.3 | 2 | 9.3% |
| | **Total** | **$61.5** | **$51.9** | **$113.4** | **20** | **10.6%** |

31 The TO Agreement calls for TOs to submit normal ratings on base (non-contingency) constraints and emergency ratings on contingency constraints ("temporary" flow that can be reliably accommodated for two to four hours). Because most constraints are contingency constraints (i.e., the limit is less than the rating to prepare for additional post-contingency flows), it is generally safe to use the emergency ratings.

32 We used temperature and engineering data to estimate the increase in transmission ratings that would result from temperature adjustments. To estimate the effects of using emergency ratings for facilities for which only normal ratings have been provided, 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.

Across the past two years, the results show average benefits equal to 12 percent of the real-time congestion value, including an average of $64 million per year for ambient temperature-adjusting the ratings and $50 million per year for using emergency ratings. 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, as one would expect. The Analytic Appendix details how these estimated benefits in 2020 are distributed in the areas served by transmission owners.

#### *Actual Saving 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 transmission owner adjusts its ratings on an hourly basis to maximize the benefits, and the benefits are substantial, as shown in Table 7. These benefits are estimated by multiplying the rating increases (from the static rating level) by the marginal value of the transmission capacity as measured by the prevailing shadow prices.

**Table 7: Estimated Achieved Savings by Two Transmission Owners**
2019–2020

| | Savings ($ Millions) | Share of Congestion | Facilities in Program |
|---|---|---|---|
| **Midwest** | $10.2 | 4.8% | 48 |
| **South** | $14.7 | 4.8% | 122 |
| **Total** | **$24.9** | **4.8%** | **170** |

The table shows that from 2019 to 2020, the actual savings totaled about $25 million—almost 5 percent of the congestion cost on these transmission facilities. This methodology is a conservative estimate of savings, 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.

In June 2020 MISO made a change to the EMS Model to enable TOs to use pre-defined nodes for use in the Dynamic Rating Software. If used, this will reduce the lead time for adding facilities to be adjusted. Unfortunately, a sizable portion of the benefits would still be lost by not being able to more quickly adjust a constraint when it begins to bind. In addition, MISO does not currently have a process to calculate AARs for its day-ahead market.

Therefore, we recommend that MISO work to improve the flexibility of its systems and processes to enable more dynamic and accurate ratings. We recommend improvements in three areas:

- *System flexibility*: Allow more rapid addition of facilities for which TOs can provide AARs or dynamic line ratings (reflecting factors other than temperature), including those identified in the outage coordination process.
- *Forecasted ratings*: New systems are needed to accept or calculate forecasted ratings for use in the day-ahead market, reliability assessments, and FTR markets.
- *Improving Validation and Transparency*: MISO should more actively validate transmission ratings, which will require new processes and the collection of key data (e.g., limiting elements, post-contingent actions, and times associated with the STEs).

Together, these changes will substantially improve the utilization of MISO's transmission network and ultimately lower the costs to MISO's customers. These recommended changes have been introduced in the MISO Integrated Roadmap and initially have been prioritized as a high priority. 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 VI.E of the Analytic Appendix estimates the increase in benefits associated with these improvements in system flexibility.

***Progress in 2020***

Progress to achieve these benefits has been slow since our initial recommendation in 2015. In 2019, we worked with MISO to develop a program concept for TOs to provide AARs and emergency ratings that we shared that with TOs and other stakeholders. In 2020, MISO facilitated a working group with TOs to develop an alternative voluntarily framework for providing AARs, but it does not address or encourage the use of emergency ratings. In the meantime, both FERC and the MISO States have strongly encouraged progress in this area.

The OMS issued a position Statement on Enhanced Line Ratings in 2020 that calls for greater transparency and the submission of AARs and emergency ratings by TOs.[33] Likewise, FERC issued a NOPR in late 2020 that would require TOs to provide AARs that would vary on an

[33] See *OMS Position Statement Enhanced Line Ratings* (https://www.misostates.org/index.php/about/position-statements)

hourly basis on all transmission facilities and requested comments on the provision of emergency ratings. The markets would benefit from a Commission mandate, which would facilitate the achievement of the sizable benefits we have been identifying in these areas.

## E. 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 and Convergence*

Congestion on M2M constraints within and outside of MISO increased in 2020:

- Congestion on MISO M2M constraints rose 37 percent to total $530 million in 2020.
- Congestion on external M2M constraints (those monitored by PJM and SPP) rose 50 percent to $51 million in 2020.
- Net payments totaling $45 million flowed from PJM to MISO in 2020, a 24 percent increase from 2019. Net payments generally flowed from PJM because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system.
- MISO's M2M settlements with SPP in 2020 resulted in net payments of $80 million from MISO to SPP, a 400 percent increase from 2019. High wind along the seams and generator retirements contributed to the increase.

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.

We also evaluate three aspects of the M2M process critical to its effectiveness: a) how competently it is administered; b) the quantities of relief the MRTOs request; and c) the criteria used to identify new M2M constraints. These three areas are discussed below.

### *Evaluation of the Administration of Market-to-Market Coordination*

Competent administration of the M2M process is essential because failing to identify or activate a M2M constraint raises:

- *Efficiency concerns*. The savings of coordinating with the NMRTO to relieve the constraint are not achieved and congestion costs are increased.
- *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 8 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 8: Real-Time Congestion on Constraints Affected by Market-to-Market Issues**
2017–2020

| Item Description | PJM ($ Millions) | | | | SPP ($ Millions) | | | | Total ($ Millions) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2017 | 2018 | 2019 | 2020 | 2017 | 2018 | 2019 | 2020 |
| **Never classified as M2M** | $85 | $5 | $1 | $4 | $109 | $15 | $14 | $34 | $194 | $21 | $15 | $38 |
| **M2M Testing Delay** | $19 | $22 | $8 | $2 | $11 | $8 | $10 | $18 | $31 | $29 | $17 | $20 |
| **M2M Activation Delay** | $6 | $11 | $1 | $3 | $12 | $7 | $1 | $2 | $18 | $18 | $2 | $5 |
| **Total** | $110 | $38 | $10 | $9 | $133 | $30 | $25 | $54 | $243 | $68 | $34 | $62 |

Historically, the largest congestion occurred on constraints that would likely pass the M2M tests, but were never tested. This prompted 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. Unfortunately, congestion associated with failure to test constraints or delays in testing constraints more than doubled in 2020, most of which is in the M2M process with SPP. Hence, we encourage MISO to evaluate ways to improve its M2M processes and timeliness of the testing process, particularly with SPP.

### *Market-to-Market Relief Software*

When a M2M constraint binds, coordination is initiated by the MRTO that is responsible for the constraint. The MRTO coordinates management of the constraint with the NMRTO by sending its marginal cost of providing relief on the constraint (i.e., the "shadow price") and the quantity of relief it would like the NMRTO to provide (at a cost not to exceed the shadow price).

Hence, a key component of successful M2M coordination is optimizing the amount of relief that the MRTO requests from the NMRTO. If the request is too low, then the NMRTO will not provide all its economic relief, resulting in higher congestion costs and potentially higher settlement costs for the NMRTO. If the request is too high, it can result in congestion oscillation (binding and unbinding repeatedly in successive intervals) that can raise costs and cause volatility in dispatch signals to resources impacting the constraints. Table 9 shows the frequency of sub-optimal relief request outcomes.

**Table 9: Frequency of Substantial Relief Request Issues**

| | MISO Flowgates | | SPP Flowgates | | All Flowgates | |
|---|---|---|---|---|---|---|
| | **Intervals** | **Share** | **Intervals** | **Share** | **Intervals** | **Share** |
| **Total Coordinated Intervals** | **13,857** | **100%** | **32,201** | **100%** | **46,058** | **100%** |
| Undersized Relief Request | 149 | 1.1% | 1,315 | 4.1% | 1,464 | 3.2% |
| Oscillation | 75 | 0.5% | 1,590 | 4.9% | 1,665 | 3.6% |
| Volatile Relief Request | 2,529 | 18.3% | 7,523 | 23.4% | 10,052 | 21.8% |
| **Intervals Exceeding Limit** | **317** | **2.3%** | **6,133** | **19.0%** | **6,450** | **14.0%** |

The current methodology results in one or more of these three flawed or inefficient relief request outcomes in 29 percent of intervals.

- *Volatile relief requests.* Volatile requests affect 22 percent of coordinated intervals, some of which occur when the NMRTO cannot provide the requested relief. There is little efficiency loss in these cases as the NMRTO is providing all available economic relief.
- *Undersized relief requests*. SPP constraints accounted for 90 percent of these intervals. We attribute this to the much greater frequency that flows exceeded the limits of SPP's constraints—19 percent versus 2 percent of MISO's constraints. Violations often result in understated relief requests because of the "Discretionary Relief Amount" flaw. Poor price convergence and higher costs is the result of requesting too little relief.
- *Oscillation*. SPP-monitored constraints were more subject to oscillation than MISO constraints, accounting for 95 percent of all oscillation intervals. The worst oscillation occurred on constraints where the MRTO has almost no redispatch capability, or when the NMRTO has a high proportion of the fast-ramping, inexpensive relief capability.

Oscillation has occurred on SPP constraints heavily impacted by MISO wind generation. On a constraint-by-constraint basis, the RTOs may choose to activate "Power Swing" software as needed to reduce or dampen the oscillation power swings. This software holds the shadow price used by the NMRTO constant based on the average shadow price of the MRTO for prior intervals. Although an improvement, it is not a long-term solution.

We continue to recommend that MISO implement improvements to its relief request software. In our prior study of the coordination between MISO and SPP from June 2018 through May 2019, we found that requesting the optimal amount of relief would have reduced the real-time congestion on M2M constraints by $41 million.

#### *Market-to-Market Test Criteria Software*

Identifying the constraints to coordinate 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 (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.[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 VI.F in 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

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.

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 most costly 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 agreed to use this software and currently only allows such transfers in limited circumstances. Hence, we recommend that 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/exchange FFE in the day-ahead market in late January 2016, but they do not actively utilize this process. Further, we 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.

## F. 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 call for a 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, 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, these external constraints often bind severely and produce substantial costs in MISO. 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 the relief of congestion 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:

- $63 million of congestion on constraints TVA generation could economically relieve;
- $43 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 much more frequent. We are investigating the justification for these TLRs, which 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.

## G. 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 in order 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:

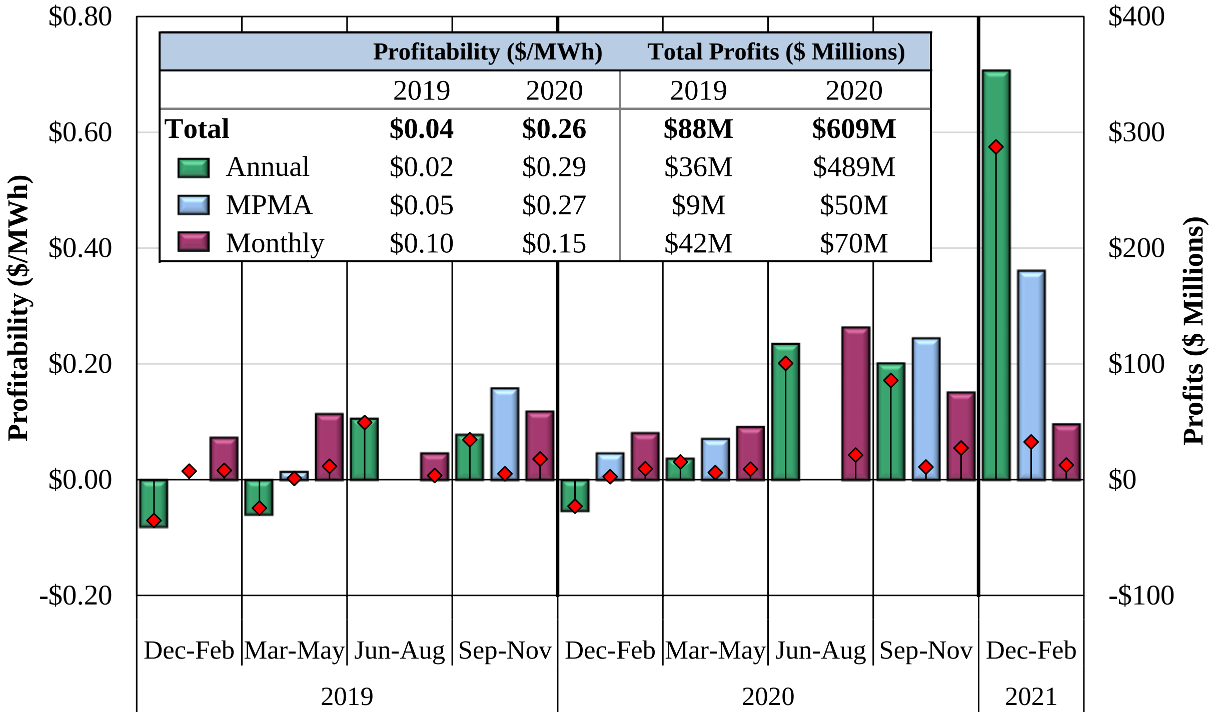
- An annual auction from June to May that includes seasonal and peak/off-peak resolution of bids, offers, and awards; and
- A Multi-Period Monthly Auction (MPMA) that yields monthly and seasonal peak/off-peak awards and facilitates FTR trading for future periods in the current planning year.

### *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 $489 million, up from $36 million in 2019. A significant portion of the increase is attributable to and extreme congestion event that occurred in February 2021.[35] However, hurricane-related events in the South that were priced in the day-ahead market in August and October were contributing factors. In prior years, FTR losses were partly attributable to market participants nominating and self-scheduling ARRs along historically unprofitable paths. This practice has steadily declined over the past four years.

**Figure 33: FTR Profits and Profitability**
2019–2020



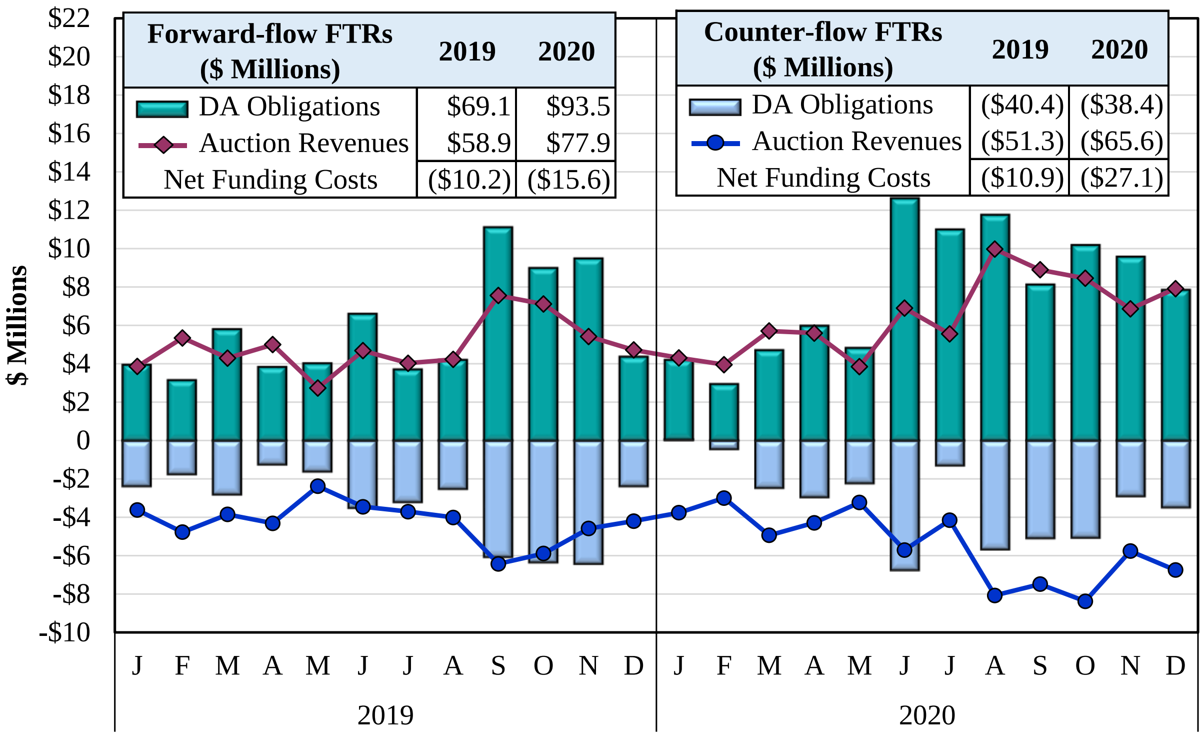

*FTR Profitability in the MPMA*. Figure 33 shows that the FTRs purchased in the MPMA and prompt month auction roughly doubled from $21 million to more than $42 million over last year. In general, the MPMA markets should produce prices that are more in line with anticipated congestion than the annual auction because they occur much closer to the operating timeframe when better information is available to forecast congestion. However, these results indicate that

35 For details on the event, see the IMM Winter 2021 Quarterly Report.

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**
2019–2020




| Forward-flow FTRs ($ Millions) | 2019 | 2020 |
|---|---|---|
| DA Obligations | $69.1 | $93.5 |
| Auction Revenues | $58.9 | $77.9 |
| Net Funding Costs | ($10.2) | ($15.6) |

| Counter-flow FTRs ($ Millions) | 2019 | 2020 |
|---|---|---|
| DA Obligations | ($40.4) | ($38.4) |
| Auction Revenues | ($51.3) | ($65.6) |
| Net Funding Costs | ($10.9) | ($27.1) |

The analysis shows that the percentage discount in the sale for forward-flow FTRs was comparable in 2019 and 2020 at a little over 15 percent, although the overall congestion was higher. In addition to selling forward-flow FTRs in the MPMA FTR auction, MISO often buys back capability on oversold transmission paths. MISO buys back capability by selling counter-flow FTRs, which are negatively priced FTRs on oversold paths. In essence, MISO is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on a constraint.[36]

36 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.

The primary reason that the FTR profits from the MPMA increased in 2020 was that the divergence in the costs incurred to buy counter-flow FTRs compared to the day-ahead congestion increased substantially. MISO paid participants 71 percent more to accept counter-flow FTRs than the value of these obligations in 2020, up from 27 percent in 2019. Much of this was related to market-to-market constraints.

Overall, these results indicate that the MPMA is less liquid than is necessary to erase the systematic differences between FTR prices and values. The best option for addressing this issue is to examine the rules and requirements that may be limiting participation in the FTR markets. If barriers to participation can be identified and eliminated, we would expect better convergence between the auction revenues and the associated day-ahead FTR obligations. Additionally, if liquidity and performance can be improved, we recommend that MISO eliminate the arbitrary negative auction residual restriction since there is no need to require each auction strip to have a positive residual. MISO could consider applying positive residuals from prior MPMA cycles to resolve infeasibilities for the prompt month. This will allow MISO to enter the day-ahead market with a feasible set of FTR obligations. Alternatively, 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.

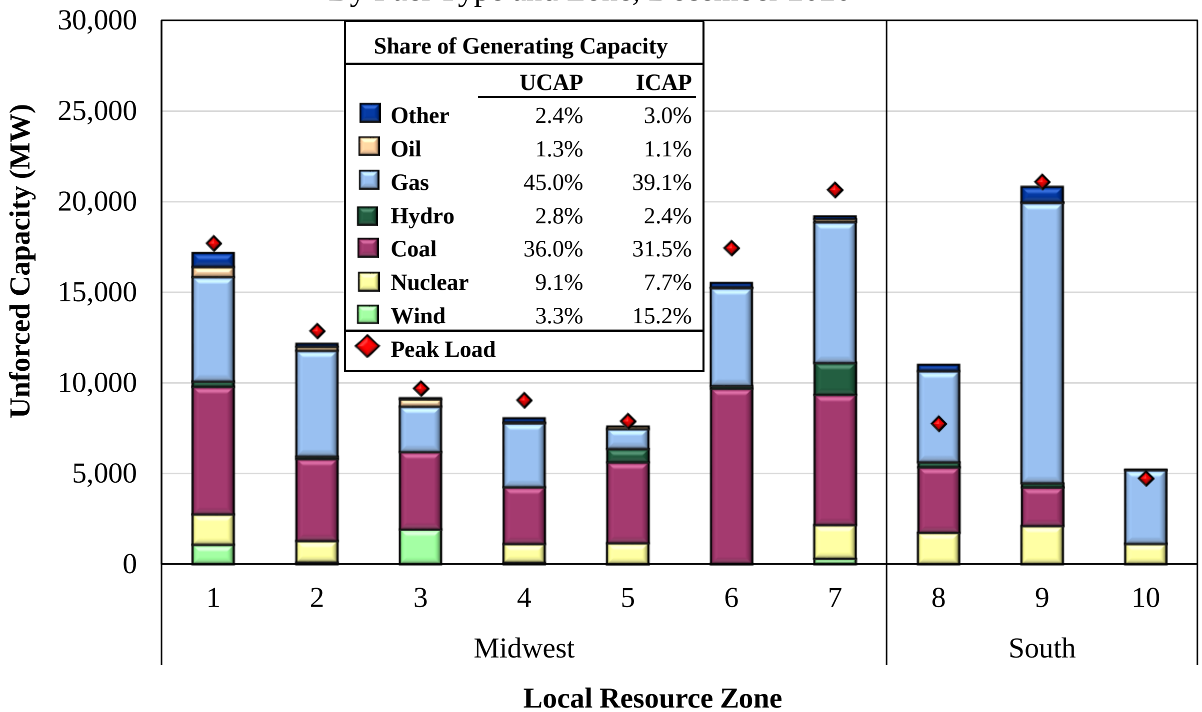
# VII. RESOURCE ADEQUACY

This section evaluates the performance of the markets in facilitating the investment and retirement decisions necessary to maintain the 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 35 shows the distribution of Unforced Capacity (UCAP) at the end of 2020 by zone and fuel type, along with the coincident peak load in each Local Resource Zone (LRZ).[37] 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 35: Distribution of Existing Generating Capacity**
By Fuel Type and Zone, December 2020



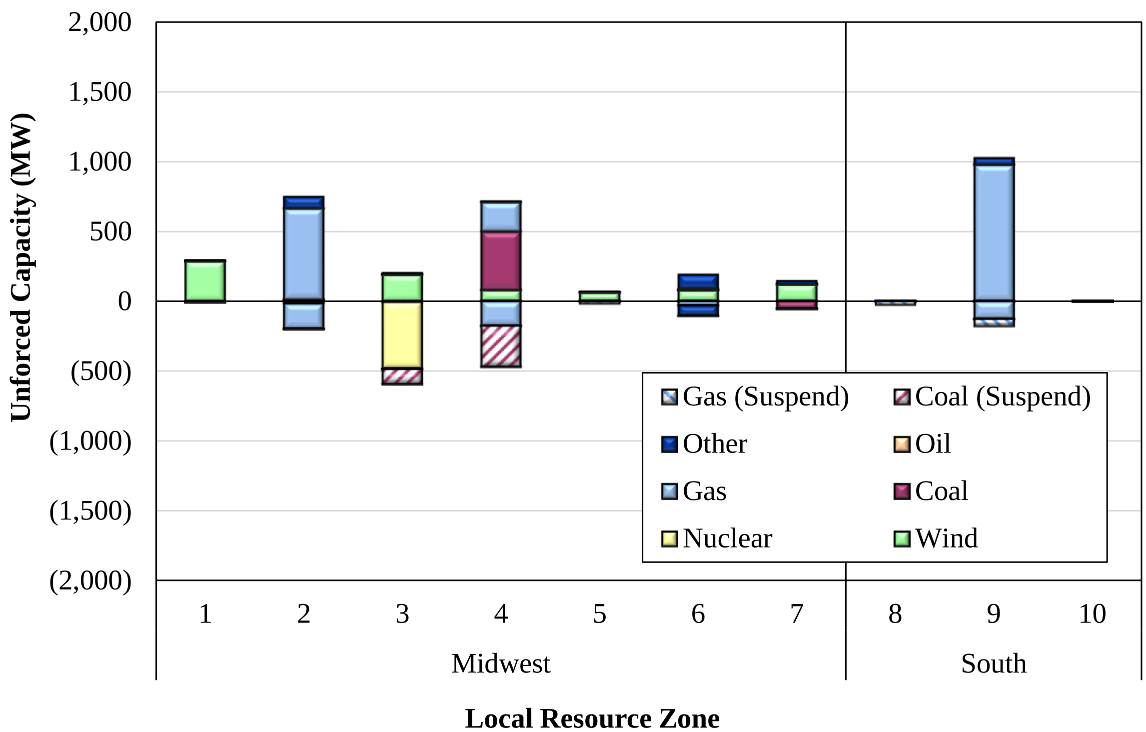

This figure shows that gas-fired resources account for a larger share of MISO's capacity than any other capacity type, including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from the MISO South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

37 UCAP was based on data from the MISO PRA for the 2020-2021 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. However, this trend reversed in 2020. Figure 36 shows the capacity additions (positive values) and losses during 2020. The hatched bar indicates suspended resources, which rarely return to service.

**Figure 36: Distribution of Additions and Retirements of Generating Capacity**
By Fuel Type and Zone in 2020




### *Capacity Losses*

In 2020, 2 GW of resources retired or suspended operations in MISO, a nearly 50 percent decline from both 2018 and 2019. These retirements include a nuclear unit that was unable to cover its going-forward costs with market revenues. These retirements produced a net unforced capacity loss of 1.6 GW. While coal resource retirements were not significant in 2020, we expect baseload retirements to continue in the near term because of sustained low natural gas prices and the weak economic signals provided by MISO's current capacity market.

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, MISO may then designate a resource as a System Support Resource (SSR) and provide compensation. An SSR cannot retire or be suspended until a reliability solution, such as transmission upgrades, can be implemented or the reliability condition no longer exists. SSR status has been granted infrequently, and currently no resources in MISO are designated SSR.

### *New Additions*

More than 8 GW of new capacity entered MISO in 2020. A large, 1 GW natural gas-fired combined-cycle resource entered in MISO South in a key constrained area. More than 5 GW (nameplate) of wind capacity entered, but their total UCAP value is roughly 750 MW because they provide less reliability than conventional resources. Additional investment in wind resources is likely to occur given continued Federal subsidies and the estimated $6.5 billion in Multi-Value Projects (MVP) to expand transmission from favorable wind areas.

## C. Planning Reserve Margins and Summer 2021 Readiness

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted summer peak loads in 2021. 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 10 presents a base case and four additional scenarios that more realistically represent the range in MISO's summer peak reliability margin.

**Table 10: Summer 2021 Planning Reserve Margins**

| | | Alternative IMM Scenarios* | | | |
|---|---|---|---|---|---|
| | | | | High Temperature | |
| | Base Scenario | Realistic Scenario | Realistic <=2HR | Realistic Scenario | Realistic <=2HR |
| **Load** | | | | | |
| Base Case | 122,397 | 122,397 | 122,397 | 122,397 | 122,397 |
| High Load Increase | - | - | - | 7,528 | 7,528 |
| **Total Load (MW)** | 122,397 | 122,397 | 122,397 | 129,925 | 129,925 |
| **Generation** | | | | | |
| Internal Generation Excluding Exports | 134,953 | 134,953 | 134,953 | 134,953 | 134,953 |
| BTM Generation | 4,463 | 4,463 | 3,167 | 4,463 | 3,167 |
| Unforced Outages and Derates** | (920) | (10,141) | (10,141) | (17,741) | (17,741) |
| Adjustment due to Transfer Limit | (3,519) | (431) | - | - | - |
| **Total Generation (MW)** | 134,977 | 128,845 | 127,980 | 121,676 | 120,380 |
| **Imports and Demand Response***** | | | | | |
| Demand Response | 7,152 | 5,364 | 3,123 | 5,364 | 3,123 |
| Firm Capacity Imports | 3,929 | 3,929 | 3,929 | 3,929 | 3,929 |
| **Margin (MW)** | 23,661 | 15,741 | 12,634 | 1,044 | (2,493) |
| **Margin (%)** | **19.3%** | **12.9%** | **10.3%** | **0.8%** | **-1.9%** |
| **Expected Capacity Uses and Additions** | | | | | |
| Expected Forced Outages | (6,971) | (6,971) | (6,971) | (6,971) | (6,971) |
| Non-Firm Net Imports in Emergencies | 4,293 | 4,293 | 4,293 | 4,293 | 4,293 |
| **Expected Margin (MW)** | 20,983 | 13,063 | 9,956 | (1,634) | (5,171) |
| **Expected Margin (%)** | **17.1%** | **10.7%** | **8.1%** | **-1.3%** | **-4.0%** |

* Assumes 75% response from DR.

** Base scenario shows approved planned outages for summer 2021. Realistic cases use historical average unforced outages/derates during peak summer hours. High temp. cases are based upon MISO's 2020 Summer Assessment.

*** Cleared amounts for the 2021/2022 planning year.

*Base Case*. We have worked closely with MISO to align our Base Case with MISO's assumptions in its *2021 Summer Resource Assessment*, including the 1,900 MW transfer limit assumption between MISO South and Midwest.[38] This case 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, 2020. The planning reserve margin in this case is 19.3 percent, which exceeds the Planning Reserve Margin Requirement (PRMR) of 18.3 percent.

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

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

In this Realistic Scenario, the planning reserve margin falls to 12.9 percent, well below the 18.3 percent capacity requirement. 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 the shortages when they occur. Hence, the table includes additional imports that reflect the average amount of additional imports during emergency conditions.[39] 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 to a modest 5 percent forced outage rate. When offset by the non-firm imports, the realistic margin falls to roughly 11 percent.

Unfortunately, even the realistic scenario is likely to be excessively optimistic because it assumes all resources will be available when an emergency occurs. However, since emergencies are often precipitated by unforeseen events, MISO has historically detected and declared emergencies between 10 minutes and 4 hours in advance. Because a large quantity of emergency resources have 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

38 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.

39 Our additional imports are consistent with the non-firm external support assumptions in MISO's sub-annual construct proposal. See November 2020 RASC Item 4a, *Reliability Requirements and Sub-Annual Construct (RASC010, 011, 012)*.

reduces estimated emergency demand response capacity and behind-the-meter generation. This lowers the planning reserve margin to 10.3 and further to 8.1 percent after accounting for expected forced outages and non-firm summer imports.

*High Temperature Cases*. We include two additional cases that modify the Realistic Scenarios to include the effects of hotter than normal summer peak conditions. The high-temperature cases are important because hot weather can significantly affect *both* load and supply. High ambient 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.[40] 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 -1.3 to -4.0 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 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 2021 but may run short if the peak demand conditions are much hotter than normal. Going forward, planning reserve margins will likely continue to decrease as fossil and nuclear resources retire and are replaced by renewable resources. Additionally, we are concerned that an increasing amount of the capacity reserve margin is being provided by LMRs whose availability is limited. Therefore, it remains important for the capacity market and shortage pricing to provide the efficient economic signals to maintain an adequate resource base.

## 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, including decisions to build new resources, make capital investments in or retire existing resources, and import or export capacity.

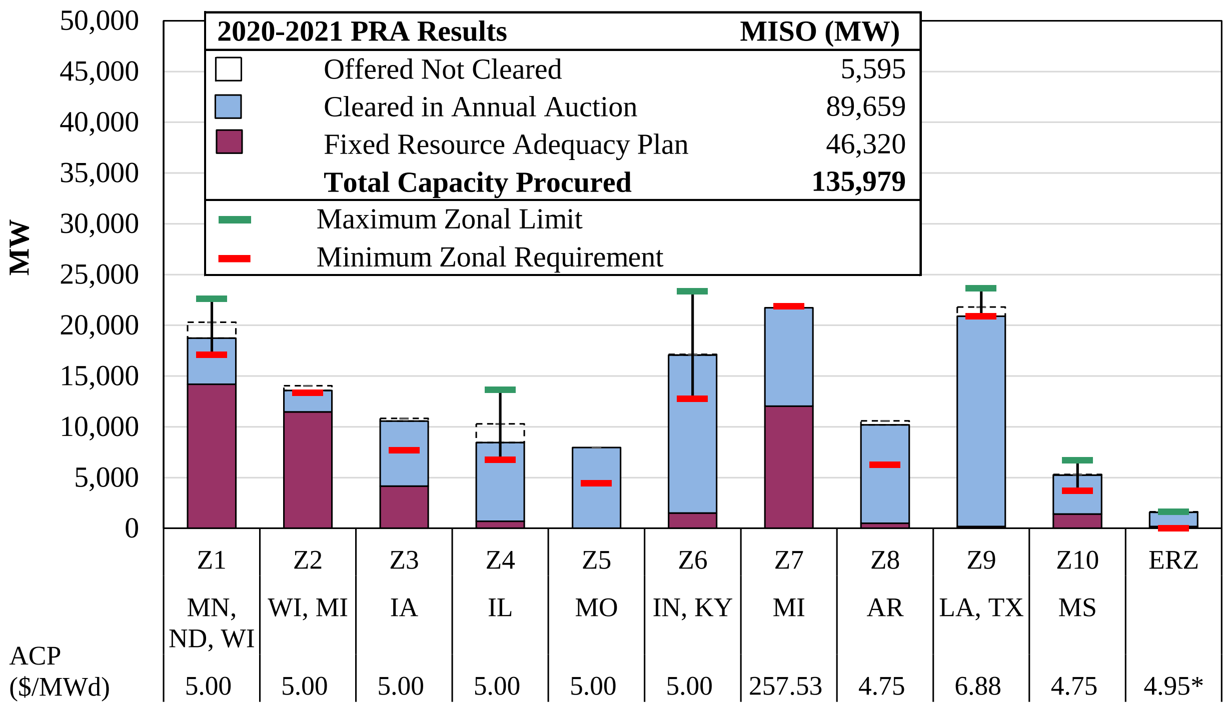
MISO's Resource Adequacy Construct allows load-serving entities (LSEs) to procure capacity to meet their Module E requirements either through bilateral contracts, self-supply, or the PRA. Resources clearing in MISO's PRA receive capacity revenues that, in addition to energy and ancillary services market revenues, should signal when new resources are needed.

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

### *PRA Results for the 2020–2021 Planning Year*

Figure 37 shows the outcome of the PRA held in late March 2020 for the 2020–2021 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 37: Planning Resource Auctions**
2020–2021 Planning Year




*Weighted Average Clearing Price

*Prices.* Zone 7 was short of the local clearing requirement and cleared at the $257.53 per MW-day price cap set at the Cost of New Entry (CONE) in that zone.[41] Zones 1 through 6 and 8 through 10 cleared at clearing prices between $4.75 per MW-day and $6.88 per MW-day. The prices outside of Zone 7 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 the Subsection G, discussing capacity market design.

41 In January 2020, FERC accepted MISO's Tariff revisions (Docket No. ER20-129-000) that disqualify resources that will be on outages that exceed 90 days during the first 120 days of the planning year. This resulted in some capacity being disqualified because of extended outages across the summer months.

### *Qualification of Supply in the PRA*

MISO's PRA rules allow some resources that provide little reliability value to provide capacity, such as Load-Modifying Resources (LMRs) with long notification times. Additionally, MISO does not procure capacity for all of its firm load. Resolving these concerns would allow prices to better reflect the value of capacity in MISO. In Table 11, we show the effects that addressing these issues would have had on prices in the 2021–2022 PRA.

Starting with the actual PRA clearing prices in the 2021–2022 auction, we produce scenarios that show the PRA clearing prices that would have resulted if the supply were adjusted to:

a) disqualify LMRs that require more than six hours of notification time to deploy[42], and

b) reflect the requirement to serve firm behind-the-meter load.[43]

The individual scenarios were then combined to show the impact of implementing both recommendations together. We evaluate the scenarios against the current capacity auction construct that relies on a vertical demand curve. We also cleared the resources assuming a sloped demand curve, a long-standing recommendation intended to allow the PRA to facilitate efficient investment and retirement decisions.

**Table 11: Alternative Capacity Auction Clearing Prices**
2021–2022 Planning Resource Auction

| **Alternative Capacity Auction Scenarios** | **Affected UCAP** | **Vertical Demand Curve Prices** | | **Sloped Demand Curve Prices** | |
|---|---|---|---|---|---|
| | | **South** | **Midwest** | **South** | **Midwest** |
| Base Scenario | | $0.01 | $5.00 | $28.31 | $172.86 |
| - LMR > 6 hr Notification Time | 1,077.6 | $0.10 | $12.88 | $55.57 | $190.54 |
| + Procurement for BTM Firm Load | 261.7 | $0.05 | $5.00 | $45.11 | $173.33 |
| **Combination of Alternative Scenarios** | 1,339.3 | $0.50 | $14.90 | $72.37 | $191.00 |

42 FERC accepted Tariff changes regarding LMR accreditation on May 18, 2020, Docket No. ER20-1846-000. Effective for the 2022-2023 PRA, LMRs get only 50 percent capacity credit if notification times are over 6 hours (but not more than 12 hours) and a minimum of 10 interruptions must be allowed. Effective for the 2023-2024 PRA, resources with notification times over 6 hours will get no capacity credit.

43 We estimate the additional MW needed to serve BTM firm load by increasing the process load served for each generating station by the PRM margin (9.4 percent) and then converting the total to an ICAP basis. The difference between this total and actual GVTC is converted back to a UCAP basis to determine the excess ZRCs included in the auction that are needed for BTM firm load. We assume that all process load is firm for this analysis. MISO would need to verify the actual portion that is firm on a plant specific basis when implementing this recommendation.

These scenarios show that improving the qualification of LMRs and procuring for all of MISO's firm load together would have tightened the capacity margin by 1,339 MW. Prices in the Midwest region would have cleared at roughly $15 per MW-day under the vertical demand curve. Improving the representation of demand in the capacity market has much greater effects. The sloped demand curve cases show that the prices would have been $191 per MW-day in the Midwest and $72 in the South after implementing our recommended improvements. These prices efficiently reflect the underlying supply and demand for capacity as discussed below in Subsection G.

***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 limited the transfer capability in the South to North direction to 1,900 MW in the 2020–2021 PRA. This constraint bound and caused a small amount of price separation between MISO South and MISO Midwest. This limit was held at 1,900 MW for the 2021–2022 PRA, and it again separated prices with MISO South being export constrained. Increasing the limit to an expected limit 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 coordinated 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. 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 2020.

Net revenue is the revenue a new 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 38 and Figure 39 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.

**Figure 38: Net Revenue Analysis**
Midwest Region, 2018–2020

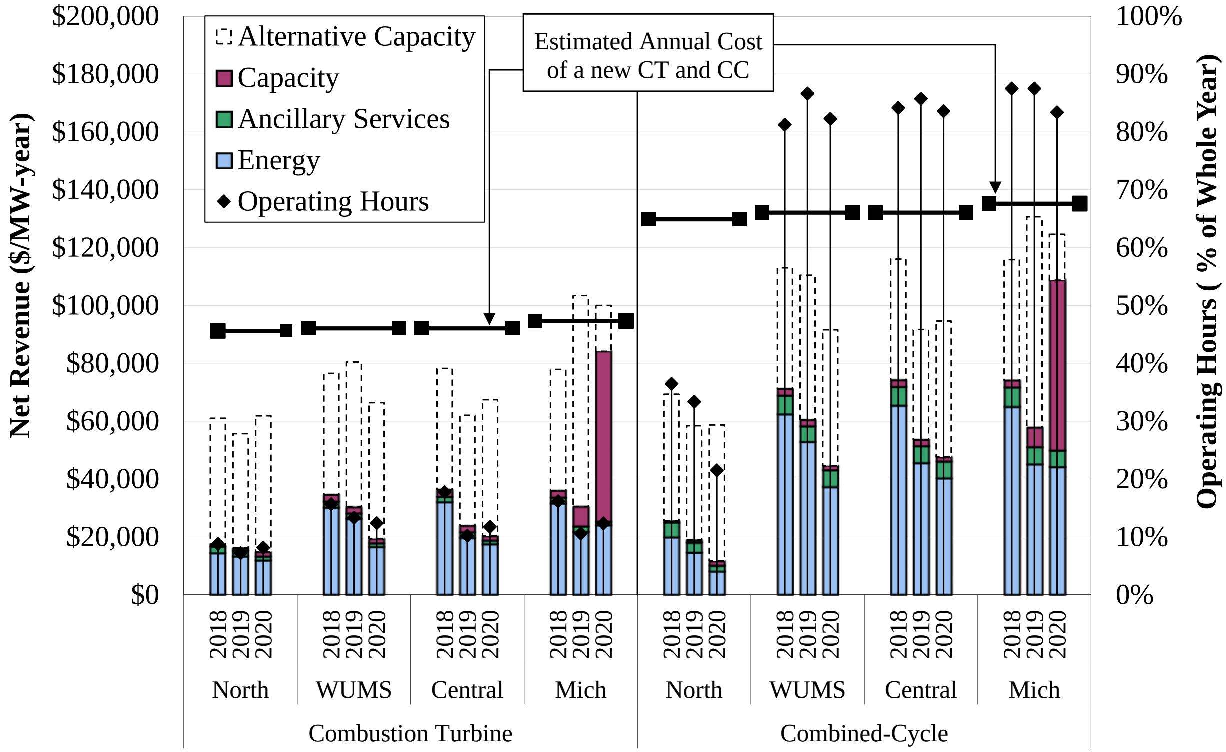
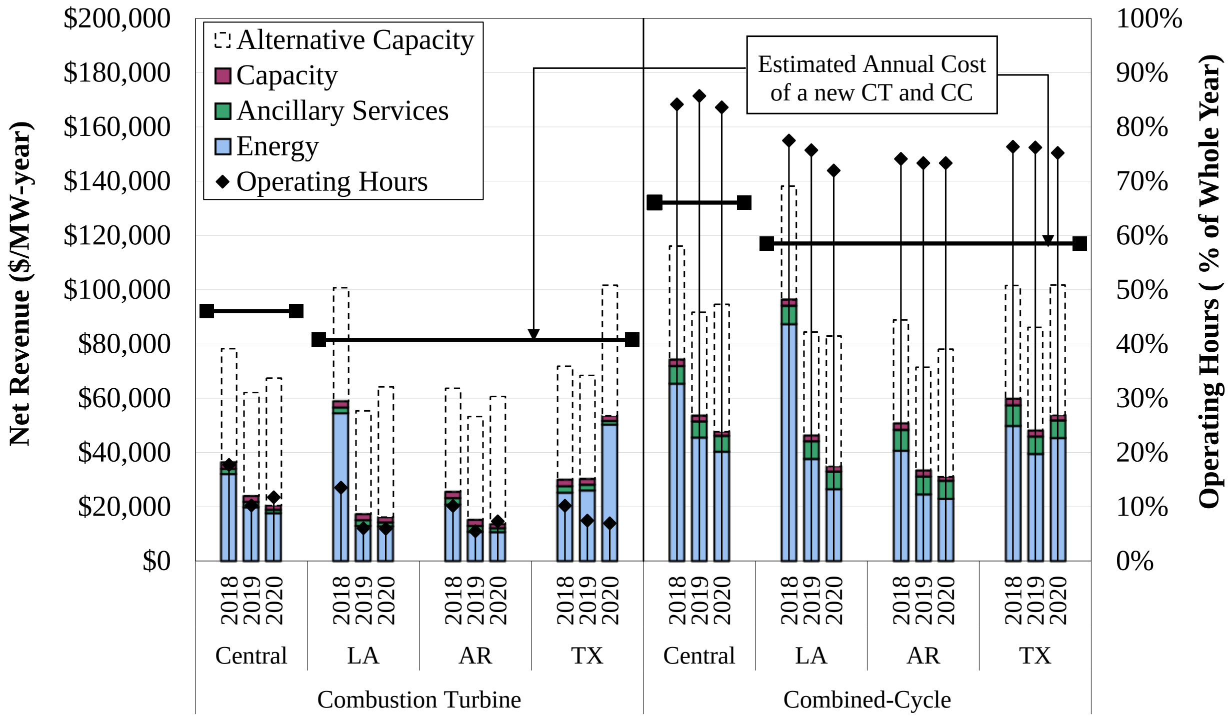



**Figure 39: Net Revenue Analysis**
South Region, 2018–2020




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

Net revenues fell in most regions in 2020, as lower natural gas prices contributed to lower energy and ancillary services prices throughout MISO. Net revenues were not sufficient to motivate investment in a CT or a CC in any location. The relatively low net revenues are consistent with expectations because of low natural gas prices, infrequent shortages, the prevailing capacity surplus, and capacity market design issues. Lower capacity auction clearing prices in almost all zones in the 2020–2021 PRA was a contributing factor to the lower net revenues. In 2019 and 2020, two new 1,000 MW combined-cycle resources came online in Louisiana, which led to fewer congestion-related price spikes in the past two years. Combustion turbine net revenues increased significantly in Texas. This was primarily due to VOLL prices in that region on August 27 after MISO instructed a firm load shed in response to Hurricane Laura.

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 sloped demand curve in the Planning Resource Auctions, the annual net revenues would have increased year over year for both resource types in all regions. This would have made CTs profitable to build in Michigan and Texas.

The lack of the sloped demand curve raises particularly timely concerns. MISO's capacity surplus is dissipating as resources face substantial economic pressure. Competitive suppliers are facing increasing incentives to export capacity to PJM or retire. To improve these price signals, we recommend a number of changes to both the energy and capacity markets in this Report. The capacity market design recommendations are discussed in Subsection G.

## 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 to suspend or retire 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 technology in MISO: coal, nuclear, and wind. Our analysis compares the annual resource net revenues to the GFCs and is shown in Figure 40. 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 VII.F.

**Figure 40: Capacity at Risk by Technology Type**
2020

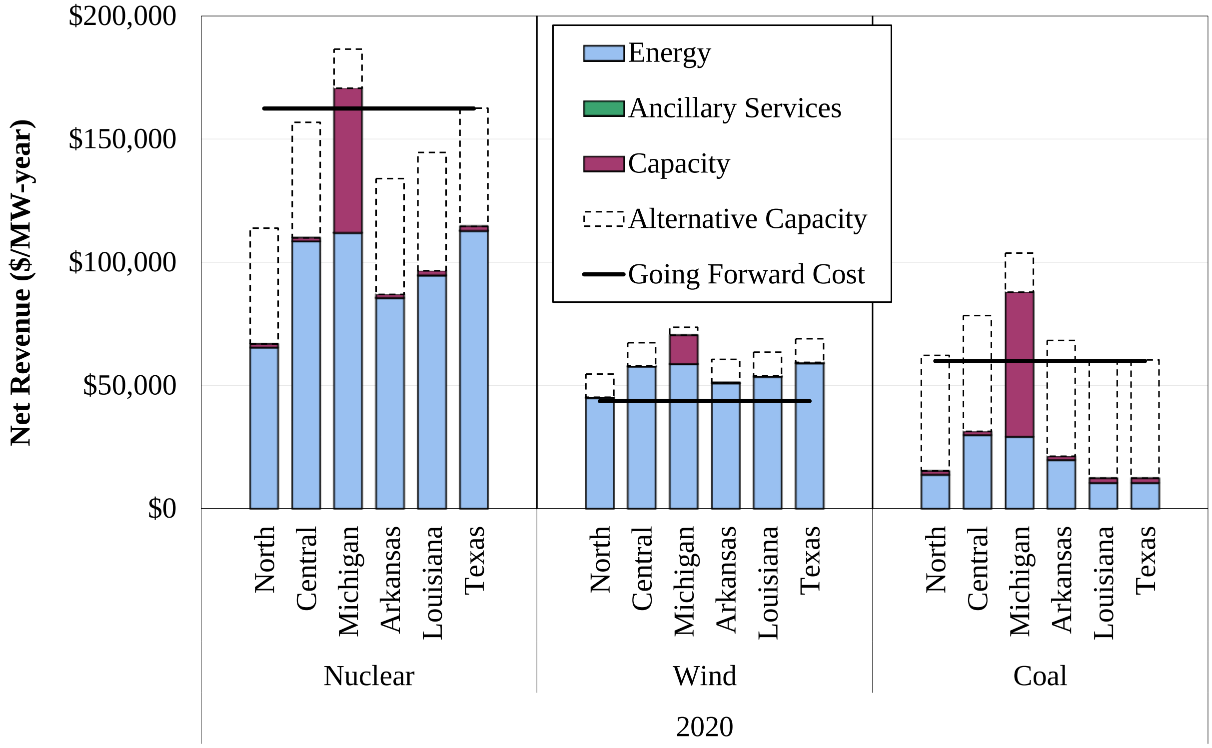



Figure 40 shows that while wind resources are more than revenue adequate, even without including tax credits, typical coal and nuclear resources exhibit revenue shortfalls under the current capacity construct. Persistent low natural gas prices have suppressed energy prices in the past few years, and revenues from the capacity auction do not offset lower energy prices. 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, these resources would be uneconomic to continue operating at prevailing prices. In fact, were MISO's coal resources to base retirement decisions on economic signals from MISO's current energy and capacity markets, 39 GW of coal resources would retire. This is unrealistic in the near term because resource retirements would result in higher capacity prices once shortages begin to occur.

Figure 40 also shows that were MISO to price capacity efficiently (by adopting a sloped demand curve), typical coal resources would be able to recover their GFCs in most regions. However, typical nuclear resources in a number of zones would still be unable to recover their GFCs. Overall, this analysis underscores how MISO's poorly designed capacity market can distort market signals and 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 VII.F of the Analytic Appendix.

## G. Capacity Market Design

We have consistently expressed concern in the past about the low clearing prices in the PRA and have explained that it is attributable to a fundamental design flaw. The PRA is adversely affected by at least two factors discussed in this subsection:

(1) The design of the PRA demand curve; and

(2) The local resource zones that do not adequately reflect transmission limitations.

### *PRA Demand Curve*

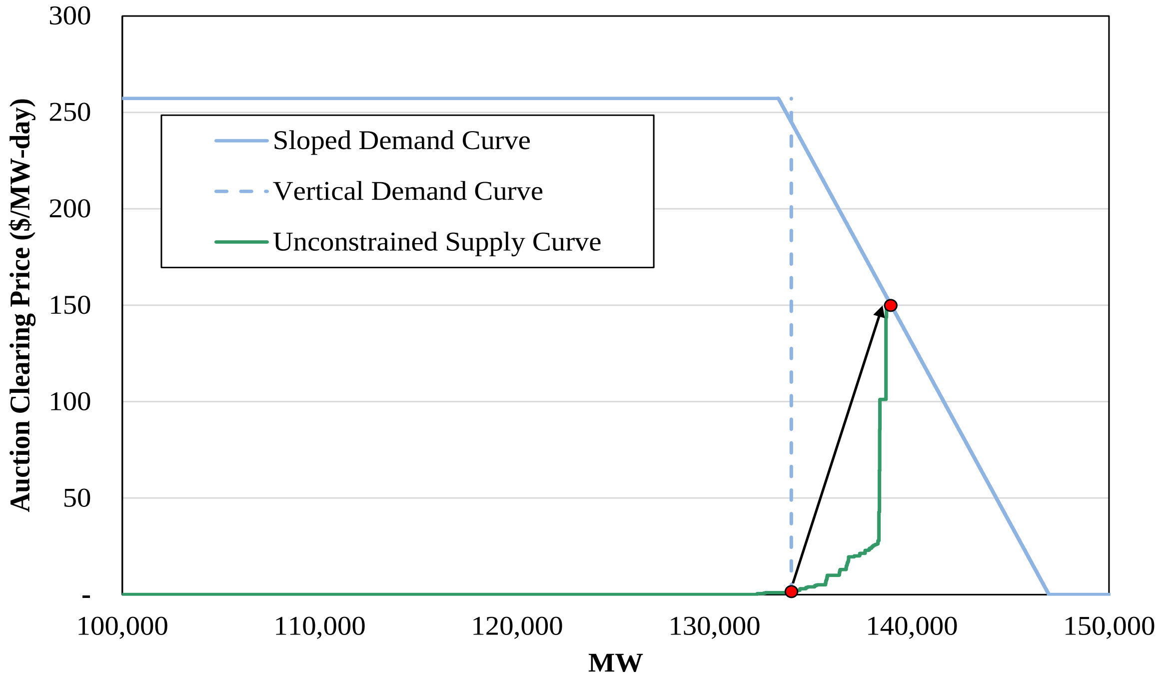
The demand for capacity in the PRA continues to poorly reflect the true reliability value of capacity and undermines the market's ability to provide efficient economic signals. The demand in MISO's PRA is set at the single level necessary to satisfy MISO's minimum planning reserve requirements with the price capped at a deficiency price based on the cost of building a new resource. This single-quantity demand 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 will increase system reliability and lower real-time energy and ancillary services costs for consumers, although these effects diminish as the surplus increases. The contribution of surplus capacity to reliability can only be captured by a sloped demand curve. The fact that a vertical demand curve does not reflect the underlying value of capacity to consumers is the source of our major concerns associated with the PRA market design.

We have sought to address this flaw by recommending that MISO implement a sloped demand curve. A sloped demand curve would produce more stable and predictable pricing, which would increase the capacity market's effectiveness in providing incentives to govern investment and retirement decisions. A sloped demand curve also reduces the incentive to exercise market power because a market with a vertical demand curve is highly sensitive to withholding. Clearing at the deficiency level creates a strong incentive for suppliers to withhold resources to raise prices. Withholding in such a market is nearly costless because the foregone capacity sales would otherwise be priced at close to zero. The benefits of a sloped demand curve will increase as planning reserve margins fall due to competitive resources continuing to retire.

To demonstrate the significance of the design flaw, we simulated the clearing price in MISO that would have prevailed in the 2021–2022 PRA if MISO employed sloped demand curves in the PRA (Appendix Section VII.G describes the assumptions underlying this curve). Figure 41 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 each resource's offered capacity. Resources that are self-supplied in accordance with Fixed Resource Adequacy Plans are represented with $0 offers.

**Figure 41: Supply and Demand in 2021–2022 PRA**




In the actual 2021–2022 MISO PRA, Zones 1 through 7 cleared at $5.00 per MW-day, and Zones 8 through 10 cleared at $0.01 per MW-day. Almost 134 GW of capacity cleared in the 2021–2022 auction. Alternatively, in our sloped demand curve simulation, we found that nearly 140 GW of capacity cleared and roughly 700 MW of offered capacity would not have cleared. Auction clearing prices by zone would have been:

- $172.86 per MW-day in Zones 1 through 7 (Midwest); and
- $28.31 per MW-day in Zones 8 through 10 (South), with external zones falling between the two.

While the Sub-Regional Power Balance Constraint still bound in the South to North direction, 2.9 GW more capacity cleared in the South compared to the actual auction. The prices in the Midwest zones are roughly 35 times higher than the actual clearing prices. While the sloped demand curve prices are a more accurate reflection of the marginal reliability value of capacity in MISO, they are still roughly 70 percent of the CONE for new resources in the Midwest and 10 percent for new resources in the South. Importantly, however, this price would motivate competitive suppliers to keep economic resources from retiring or exporting to other RTOs because it would cover the GFCs for most of the existing resources. This enormous difference in price highlights the serious impact of the flaw in the current market design and the benefits of remedying the flaw by implementing a sloped demand curve.

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

Based on the simulation described in the prior subsection, we estimated 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 12.

**Table 12: 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 | $185.6M | -$65.8M | $119.8M |
| Municipal/Cooperative | $89.1M | -$50.3M | $38.8M |
| Merchant | $349.8M | -$61.4M | $288.4M |
| Retail Choice Suppliers | | -$447.0M | -$447.0M |

This table shows that the vertically-integrated utilities would have benefited in aggregate by $119.8 million from the use of the sloped demand curve across 17 entities in that category. 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.

Municipal and cooperative entities also would have benefitted from the adoption of a sloped demand curve in the 2021–2022 auction, with a net gain across the class of $38.8 million per year. The gain is much smaller because some municipal utilities are net buyers in the PRA and others are net sellers.

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 $349.8 million revenue through the PRA, providing more efficient signals to maintain existing resources and build new resources. This increase is offset by $61.4 million in costs for those that serve load in MISO.
- Likewise, costs borne by competitive retail load providers would have risen by $447 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.

### *Reforming the Accreditation of Capacity in MISO*

MISO's historic accreditation methodology is not aligned with the reliability value provided by different resources because: a) it does not account for unreported outages and derates or any type of outage other than a forced outage; and b) it does not recognize that inflexible resources with long lead times are less valuable than more flexible resources. This will be increasingly true as MISO's fleet transitions to rely more heavily on intermittent resources.

MISO filed a Tariff change approved by FERC in March 2019 that reduces the accredited capacity of resources taking short-notice planned outages that occur during emergency conditions.[44] However, this change had an extremely small effect because emergency events are very infrequent and because it does not include unreported outages and derates. Hence, it does little to address the accreditation concerns discussed above.

Therefore, we continue to recommend additional changes to resource accreditation based on resources' Available Capacity (ACAP) during the tightest margin hours of the year. This methodology would include all types of outages and derates including those that are not reported to MISO. We credit offline resources with availability based on their startup and notification times with longer times deemed to be less available.[45] This reflects reality because MISO often does not see tight conditions coming day-ahead or many hours in advance, which causes long-lead time offline units to contribute less to overall reliability than online or quick start resources.

The ACAP methodology would measure resource availability at times when the system needs them the most—when the real-time supply margin (total available supply minus total demand, including reserves) is smallest (we use the tightest 5 percent of hours). We calculate the supply margins on a subregional basis since tight conditions and capacity emergencies are most often called subregionally. We recognize the RDT capability to the extent that the other subregion has headroom on its resources.

The estimated impact of the proposed ACAP changes is shown in Table 13. The table shows the capacity-weighted average value of the current UCAP-based availability rate (1 minus the XEFORd) and the ACAP-based availability rate under the IMM proposed methodology. The table shows the values for each major resource category and by subregion and the entire MISO market. We exclude renewables, which should be accredited under the ELCC methodology. This analysis is discussed in further detail in Section VII.G of the Analytic Appendix.

44 Docket No. ER19-915-000.

45 Sliding scale is 100% available for lead time of 2 hours or less, 10% less per additional hour up to 11 hours, and 0% for 12 hours or more.

**Table 13: Alternative Capacity Accreditation Derates by Resource Class**

| Resource Class* | Weighted Availability Rate | | | | | |
|---|---|---|---|---|---|---|
| | Midwest | | South | | MISO | |
| | UCAP | ACAP | UCAP | ACAP | UCAP | ACAP |
| Coal | 92.6% | 80.3% | 92.7% | 62.2% | 92.6% | 78.5% |
| Combustion Turbine | 93.4% | 85.3% | 95.1% | 79.6% | 93.7% | 84.1% |
| Combined Cycle | 96.9% | 84.8% | 95.0% | 74.5% | 96.0% | 80.1% |
| Nuclear | 98.4% | 91.0% | 92.4% | 74.1% | 95.8% | 83.7% |
| Other Steam Turbine | 93.7% | 70.8% | 87.3% | 57.3% | 88.7% | 60.2% |
| Hydro | 99.1% | 84.1% | 99.5% | 88.7% | 99.2% | 85.7% |

* Includes accredited generation resources in the 2021/22 PRA that were in operation prior to 9/1/2020. A few resources are excluded due to anomalous outage patterns and low hours in the study period.

Table 13 shows that the changes proposed by the IMM would have a significant impact on the accreditation of resources. The IMM's ACAP proposal is more effective in estimating resources' expected contribution to maintaining reliability in the most critical hours than the existing accreditation methodology. This is particularly true for older peaking resources that are rarely needed but frequently fail when committed, as well as older gas steam and coal-fired resources that have long notification and start-up times. These resources provide much lower reliability value to the system because they cannot be utilized if fluctuations in intermittent resources, unexpected changes in loads, or generation outages lead to tight conditions when they happen to be offline. Our proposed accreditation changes address all these issues.

Other resources would benefit from this change because their accreditation would increase relative to the accreditation of all resources. These resource classes include most nuclear resources, most combustion turbines, and most combined-cycle generators. This is expected because these units are almost always able to provide their capacity during tight market conditions, either because they are generally running or because they can start quickly. Since the aggregate demand would be scaled down by the aggregate effect of the ACAP accreditation reduction, resources whose accreditation reduction is smaller than average should generally earn more capacity revenue.

Likewise, the fact that the accreditation of resources would fall would not likely increase capacity expenses significantly. This is true for at least three reasons:

1. The demand curve would be reduced by the translation from UCAP to ACAP,
2. MISO would be procuring more reliable ZRCs under this methodology so its capacity requirements would fall significantly; and
3. Suppliers would likely make changes in their maintenance and outage scheduling patterns to avoid being unavailable in tight hours, which we believe would significantly change accreditation levels for some of the resource types shown in Table 13:

- Combined-cycle generators show a decrease in availability under the ACAP proposal from 96 to 80 percent, which can be substantially mitigated by altering the timing of planned outages during shoulder periods, particularly in the South.
- Nuclear generators schedule planned outages more than 3 years in advance and have very little flexibility in maintenance schedules. These generators show a decrease in availability from 95 to 84 percent. A large portion of this decrease is from the scheduling of these planned outages during tight periods.

On the basis of these results, we recommend that MISO modify the current capacity accreditation construct to adopt changes that would be consistent with the IMM's ACAP proposal.[46] An additional benefit of this approach is that it would resolve all concerns with the accuracy and completeness of the reported outages and derates because the accreditation would include all outages and derates, whether they are reported or not.

***Other Recommended Improvements to the PRA***

Although a sloped demand curve 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.

*Seasonal Capacity Market.* A seasonal market would better align the revenues and requirements of capacity with the value of the capacity. In its recent RAN proposals on a sub-annual capacity construct[47], MISO has proposed four seasons, which would facilitate savings for participants by:

- Allowing high-cost units to suspend during the shoulder months or not keep the unit staffed in the months when they are unlikely to be economic to dispatch; and

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46 In 2019, MISO began exploring a similar ACAP methodology based on availability during the tightest RA hours. MISO has since rolled its ACAP proposal into one for a sub-annual (seasonal) auction construct and has presented its findings to stakeholders. MISO plans to make a FERC filing for this proposal in September 2021. See RAN Reliability Requirements and Sub-annual construct (RASC010-12).

47 See RAN Reliability Requirements and Sub-annual construct (RASC010-12).

- Allowing suppliers to retire or suspend units at four points in time during the year (between seasons) without having to purchase replacement capacity.

*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 X.D, 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.

### *Evolution and Development of MISO’s Demand-Side Resources*

In December of 2018, MISO began to evolve the LMR resource qualification process in its Tariff. The first of these changes was implemented in the 2019–2020 planning year, requiring resources to (1) offer based upon their actual seasonal availability, (2) deploy on the shortest notification times, the longest permitted limited to 12 hours, and (3) give MISO the ability to notify LMRs in advance of an emergency being called. In the 2020–2021 planning year, Demand Resources were brought more into parity with generation resources by being required to perform an annual Real Power Test, although exceptions were made subject to RERRA restrictions, and resources could choose to opt out of the tests and could elect to take a higher penalty for non-performance.

Phase II of RAN addressed the fact that many LMRs have not been available during the tightest periods as we described in Section V.E. MISO’s May 2020 filing reduced the accreditation value of resources available for fewer than 10 calls per year or registering lead times of more than 6 hours. The implementation of these changes will be phased in completely by 2023. Further Tariff changes filed in December 2020 clarify the requirements regarding LMR performance, including ensuring that LMRs are providing up-to-date information in the MISO Communication System. MISO intends to have improvements to its software in place before these Tariff changes become effective.

# VIII. External Transactions

## A. Overall Import and Export Patterns

Imports and exports play a key role in MISO because it has 12 interfaces with neighboring systems with 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 2020:

- Day-ahead and real-time net scheduled interchange (NSI) averaged 5.9 and 7.2 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 2020.
  - Hourly average real-time imports from PJM were 3.7 GW, up 54 percent from 2019.
  - 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 the interregional price differences captures substantial savings as lower-cost resources in one area displace higher-cost resources in the other area.
Significant events in 2019 that we reported last year still stand as examples that underscore this:

- On January 30, 2019, MISO declared a Maximum Generation Event in the North because of extremely cold temperatures. Prices in MISO were consistently above $600 per MWh between 8 a.m. and 11 a.m. Net imports increased by almost 10 GW above the day-ahead scheduled interchange by noon in response to the price signals.
- On November 13, 2019, record cold temperatures that affected much of the Southeast and SPP resulted in an RDT limit reduction and very high prices in the South. Exports from the South were as high as 1,000 MW when prices spiked to $1,000 per MWh. In response, exporters cut the majority of their exports and caused prices to fall in the South.

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 2020, more than 75 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.

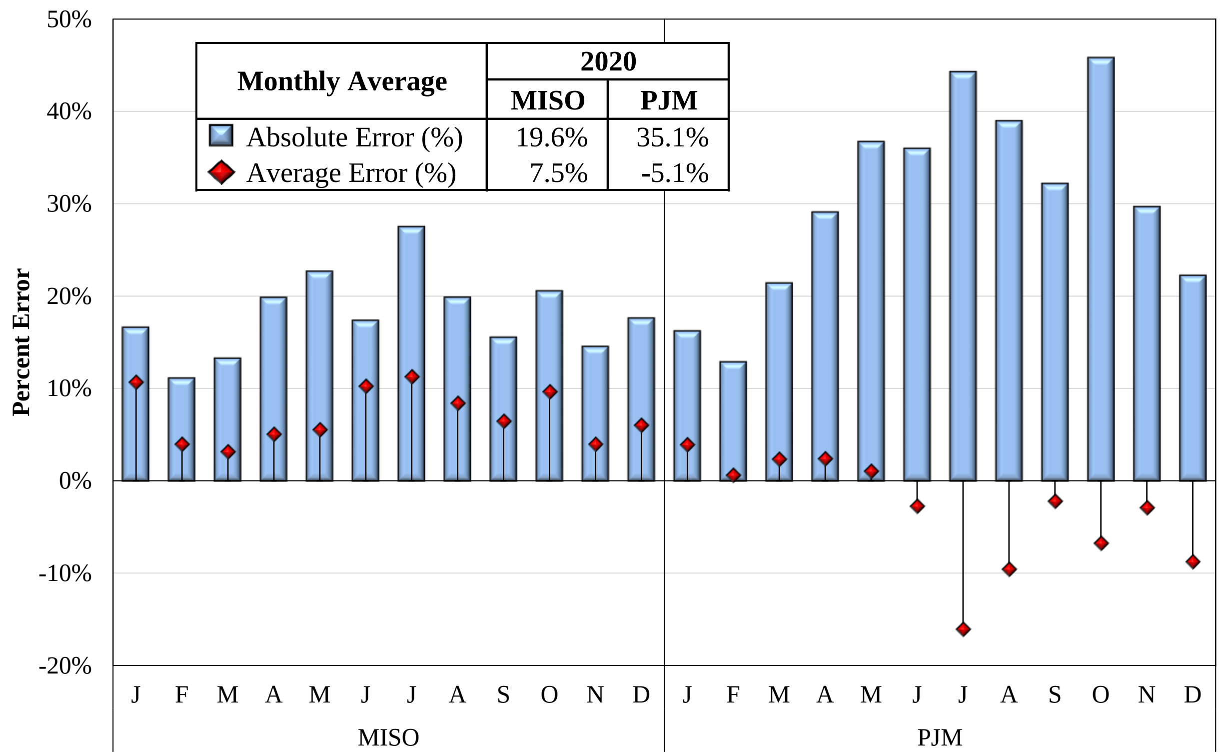
## B. Coordinated Transaction Scheduling

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 the summer of 2018, MISO identified a forecasting error that was addressed in March 2019. In 2020, the hourly average quantity of CTS transactions offered and cleared were 140 MW and 60 MW, respectively, down from 220 MW and 65 MW in 2019. Over 99 percent of these transactions 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 42, 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 42: MISO and PJM CTS Forecast Errors**
2020



This analysis shows significant inaccuracies in the forecast prices used for CTS, particularly in PJM. In 2020, the average difference between PJM's real-time LMPs and its forecast prices for the interface was -5.1 percent, and the average of the absolute difference was 35.1 percent.[48] For the same period, the average difference between MISO's real-time LMPs and its forecast prices for the interface was 7.5 percent, and the average of the absolute difference was 19.6 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.

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 5 minutes through UDS based on the most recent five-minute prices in the neighboring RTO area, which we evaluate below.

***CTS with Five-Minute Clearing***

We ran a simulation for all of 2020 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 adjust the optimal adjustment, accounting for any changes in the actual scheduled NSI, and apply 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. Table 14 summarizes these results for 2020. Table 14 summarizes these results for 2020.

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

**Table 14: CTS with Five-Minute Clearing Versus Current CTS**
2020

| | Percent of Intervals Adjusted | Production Cost Savings | Profits | Percent Unprofitable |
|---|---|---|---|---|
| **Current CTS** | 8.1% | $279,651 | -$1,294,204 | 28.3% |
| **5-Minute CTS with Fees** | 70.3% | $12,180,638 | $6,889,809 | 9.5% |

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 would have achieved more than $12 million in production costs savings versus less than $300,000 under the current process. These savings do not require large adjustments in most intervals—which average roughly 70 MW per interval.

The improvement in the incentives for participants to utilize the CTS process is also notable. The CTS participants would have earned nearly $7 million from the cleared CTS transactions compared to the losses in 2020 of $1.3 million under the current process. In fact, more than 28 percent of the current CTS transactions are ultimately unprofitable versus less than 10 percent under the recommended process. These losses are evidence of the poor price forecasts that govern the adjustments currently. Using the most recent five-minute prices is a substantial improvement and leads to more optimal CTS adjustments. Therefore, we recommend MISO pursue this improvement in the CTS process with PJM and implement this approach with SPP.

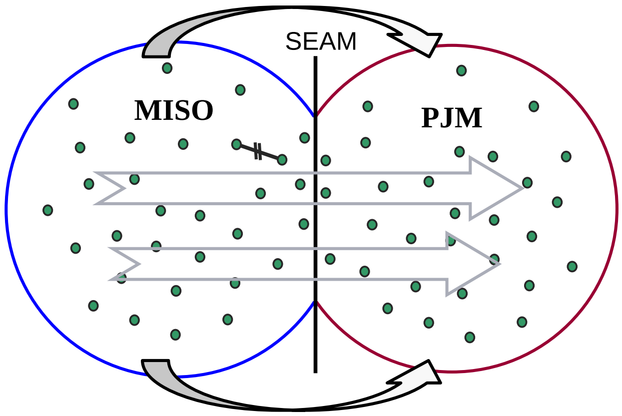
## C. Interface Pricing and External Transactions

Each RTO posts its own interface price at which it will 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.

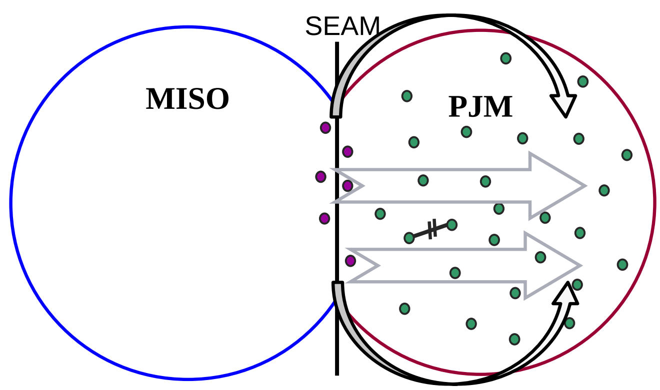
Establishing efficient interface prices would be simple in the absence of transmission congestion and losses—each RTO would simply post the interface price as the cost of the marginal resource on its system (the system marginal price, or "SMP"). Participants would respond by scheduling from the lower-cost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

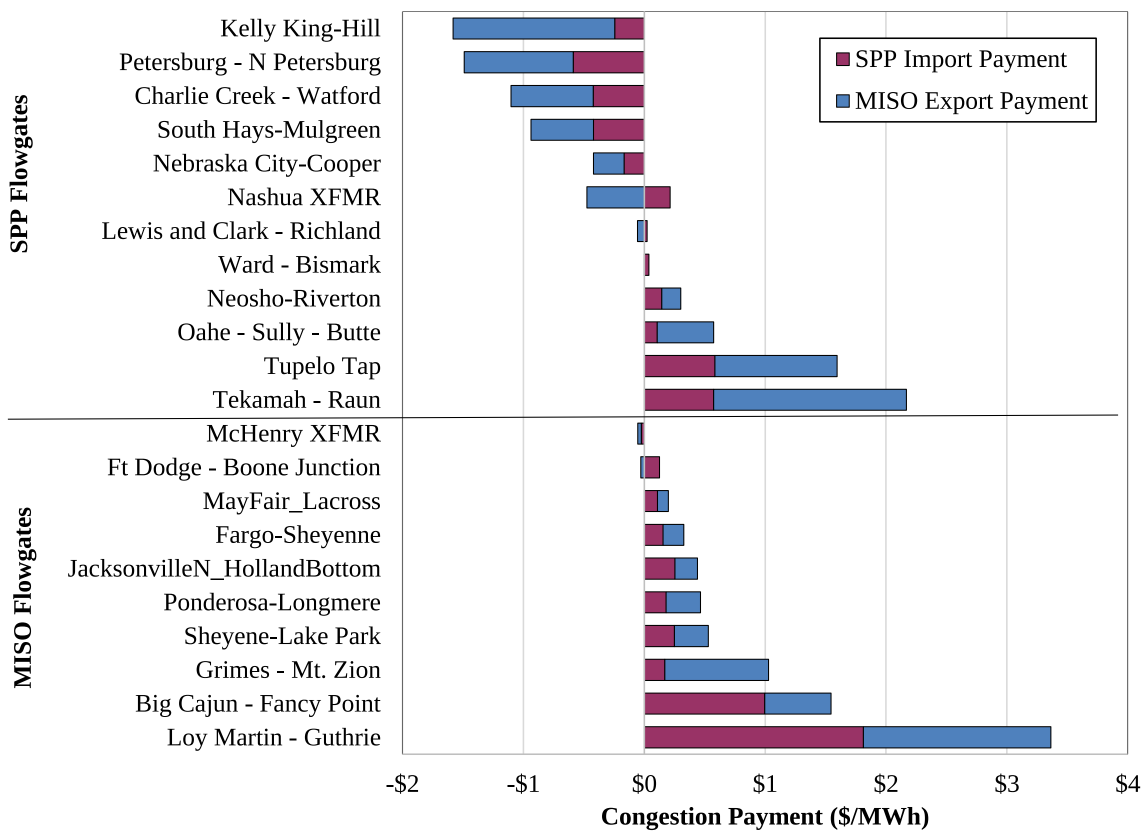



We have identified the location of MISO's marginal generators and confirmed that they are distributed *throughout* MISO, so we are concerned that the common interface definition sets inefficient interface prices. Our interface pricing studies show that in aggregate, the common interface has led to larger 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 of 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 43 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 43: 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, that 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 RTO's 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 all of the interface pricing issue associated with external constraints on all of MISO's other interfaces (excluding the PJM and SPP interfaces).

# IX. 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 2020. 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 (637) but very high in some local areas, such as WUMS (3881) and the South Region (4110), 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, 67 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 three Midwest NCAs had at least one pivotal supplier.

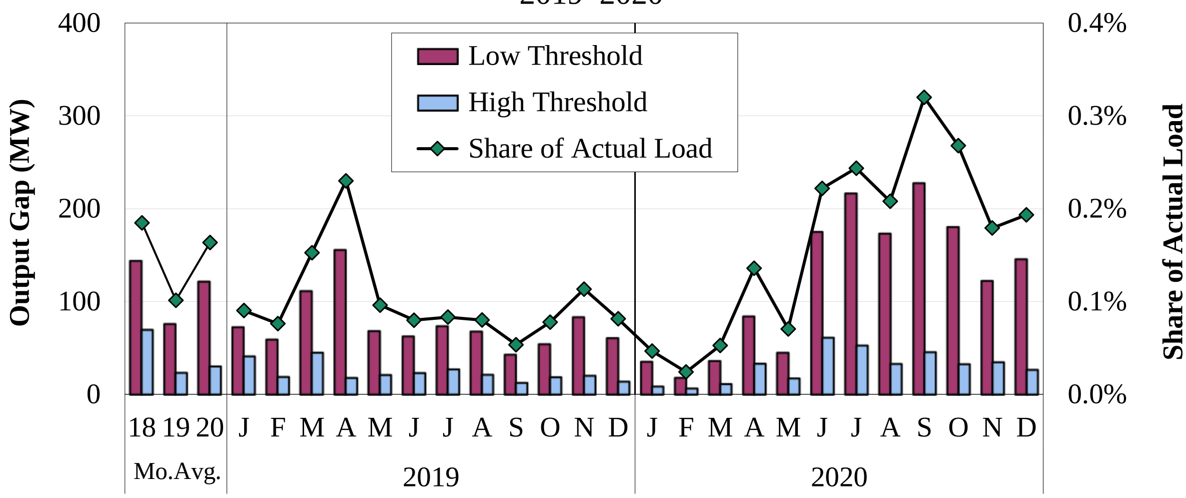
Overall, these results indicate that local market power persists, with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

## 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 2020, varying monthly from a high of 2.0 percent to a low of -2.5 percent. The negligible average mark-up indicates that MISO's energy markets produced very competitive results.

Figure 44 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 44: Economic Withholding – Output Gap Analysis**
2019–2020




**Low Threshold Results by Unit Status (MW)**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Offline | 17 | 12 | 8 | 30 | 2 | 29 | 4 | 16 | 8 | 8 | 9 | 7 | 15 | 10 | 5 | 0 | 0 | 0 | 0 | 3 | 12 | 36 | 18 | 4 | 8 | 10 | 2 |
| Online | 126 | 64 | 114 | 42 | 58 | 82 | 151 | 53 | 55 | 65 | 58 | 36 | 39 | 73 | 55 | 36 | 18 | 36 | 84 | 42 | 163 | 180 | 156 | 223 | 172 | 112 | 144 |

**High Threshold Results by Unit Status (MW)**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Offline | 14 | 10 | 7 | 24 | 2 | 26 | 4 | 10 | 7 | 8 | 9 | 6 | 12 | 10 | 5 | 0 | 0 | 0 | 0 | 3 | 11 | 31 | 16 | 4 | 7 | 7 | 2 |
| Online | 55 | 13 | 23 | 17 | 17 | 19 | 14 | 11 | 16 | 19 | 12 | 7 | 7 | 10 | 9 | 9 | 7 | 11 | 33 | 15 | 50 | 21 | 17 | 41 | 25 | 28 | 25 |

The figure shows that the average monthly output gap level was .16 percent of load in 2020, which is effectively *de minimus*. 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 2020 effectively limited the exercise of market power. Mitigation in the energy market remained infrequent, and RSG mitigation fell 23 percent. 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 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 2020, one Dynamic NCA was defined from October 23 through November 22. 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 2020, 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 2020. 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.

RSG mitigation declined 23 percent in 2020. Day-ahead RSG mitigation increased 40 percent, offset by a 58-percent decrease in real-time RSG mitigation. VLR requirements are a frequent cause of commitments and RSG. Most VLR commitments are in MISO South and are subject to tighter mitigation thresholds because competition to satisfy these requirements is limited.

# X. Demand Response and Energy Efficiency

Demand Response (DR) involves actions taken to reduce consumption when the value of consumption is less than the marginal cost to supply the electricity. DR 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 it into the MISO markets in a manner that promotes efficient pricing and other market outcomes.

## A. Demand Response Participation in MISO

DR resources can be divided into one or more of the following three categories:[49]

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

Table 15 compares the total DR participation in MISO, NYISO, and ISO-NE in the prior three years. The table shows that MISO had more than 13.5 GW of DR capability available in 2020, similar to 2019. This total will likely drop over the next few years as a result of MISO's recent and proposed accreditation changes to LMRs discussed below. MISO's demand response capability constitutes more than ten percent of peak load, which is a larger portion than in NYISO but slightly less than in ISO-NE. MISO's capability exhibits varying degrees of responsiveness. Approximately 90 percent of the MISO DR is in the form of LMRs that are interruptible load developed under regulated utility programs and behind-the-meter-generation (BTMG). The MISO DR capability also includes two types of Demand Response Resources (DRRs) that can participate in MISO's markets.

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

**Table 15: Demand Response Capability in MISO and Neighboring RTOs**
2018–2020

| | | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| **MISO[1]** | | **13,006** | **13,686** | **13,675** |
| | LMR-BTMG | 4,496 | 4,480 | 4,334 |
| | LMR-DR | 5,524 | 5,828 | 6,989 |
| | LMR-EE | 173 | 312 | 650 |
| | LMR-EDR | 1,440 | 1,544 | 568 |
| | DRR Type I | 621 | 811 | 793 |
| | DRR Type II | 78 | 88 | 101 |
| | Emergency DR | 674 | 624 | 239 |
| **NYISO[2]** | | **1,314** | **1,288** | **1,199** |
| | Special Case Resources - Capacity | 1,309 | 1,282 | 1,195 |
| | Emergency DR | 5 | 6 | 4 |
| | Day-Ahead DRP | 0 | 0 | 0 |
| **ISO-NE[3]** | | **2,988** | **3,309** | **3,686** |
| | RT DR Resources/DR Assets | 262 | 321 | 433 |
| | On-Peak Demand Resources | 2,214 | 2,440 | 2,672 |
| | Seasonal Peak Demand Resources | 512 | 548 | 581 |

[1] Registered as of December 2020. All units are MW.

[2] Registered as of July 2020. 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, 2020. Source: ISO-NE Demand Response Working Group Presentation.

## B. Demand Response Resources

Only a small portion of MISO's total DR resources can respond to MISO real-time dispatch signals and qualify as DRRs. These resources can participate in the energy, ancillary services, and capacity markets. DDRs 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.[50]

- Type II: These resources can supply varying levels of energy or operating reserves on a five-minute basis and, like generating resources, can set prices.

50 A resource can qualify 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.

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.

Thirty-one active DRRs in 2020 cleared an hourly average of 97 MW of energy in the form of demand reduction and 221 MW of contingency reserves in 2020. Type I resources accounted for 98 percent of this DRR scheduling; however, the nearly 300 percent increase in demand reduction during 2020 brought to light concerns regarding the baseline calculations that factor into DRR Type I compensation. As large baseload resources continue to retire and be replaced by renewable resources, DRRs are expected to be deployed more frequently to lessen peak loads and respond to system contingencies. It is important, therefore, to ensure that real-time markets produce efficient prices when DR resources are deployed and to ensure that the contributions of these resources are measured accurately and compensated fairly. MISO should re-evaluate its DRR measurement and verification provisions to address inefficiencies and eliminate gaming opportunities before DRR contributions rise.

## C. LMRs and EDRs

While DRRs are valuable for their ability to respond to prices, they are a very small portion of the DR in MISO. The majority of DR in MISO participate as emergency resources, including the LMR and EDR categories. MISO can deploy these resources only during a declared emergency. These resources generally are legacy demand-side programs 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).

LMRs are planning resources and thus have an obligation to curtail as instructed during emergencies. These resources do not submit an economic offer price, but deployment of LMRs 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 we show in Table 15 above, LMRs make up a large majority of DR in MISO.

In contrast to LMRs, EDRs do not have a must-offer requirement and only reflect a small portion of DR in MISO. Resources that clear MISO's PRA have the ability to 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 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. Some LMRs may participate as EDRs.

Finally, Module E of MISO's Tariff allows DR resources to count toward fulfillment of an LSE's PRMR if the resource can curtail load within 12 hours and is available during the summer months.[51] As part of the RAN initiatives, FERC-approved Tariff changes that reduce the allowable lead time for qualifying LMRs to 6 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.

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 February 2021, LMRs were deployed eight times in MISO South and twice 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 due to extremely cold weather in MISO South. We discuss the 2020 emergency events in detail in Section II.E of this Report.

## D. Energy Efficiency in MISO's Capacity Market

When demand response assets 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 has been growing rapidly and is playing a more pivotal role in satisfying MISO's resource adequacy needs. Table 16 summarizes the EE quantities over the past four PRAs. In the 2020–2021 auction the EE measures cleared 650 MW, equivalent to about one-fifth of accredited wind resource capacity.

**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 |

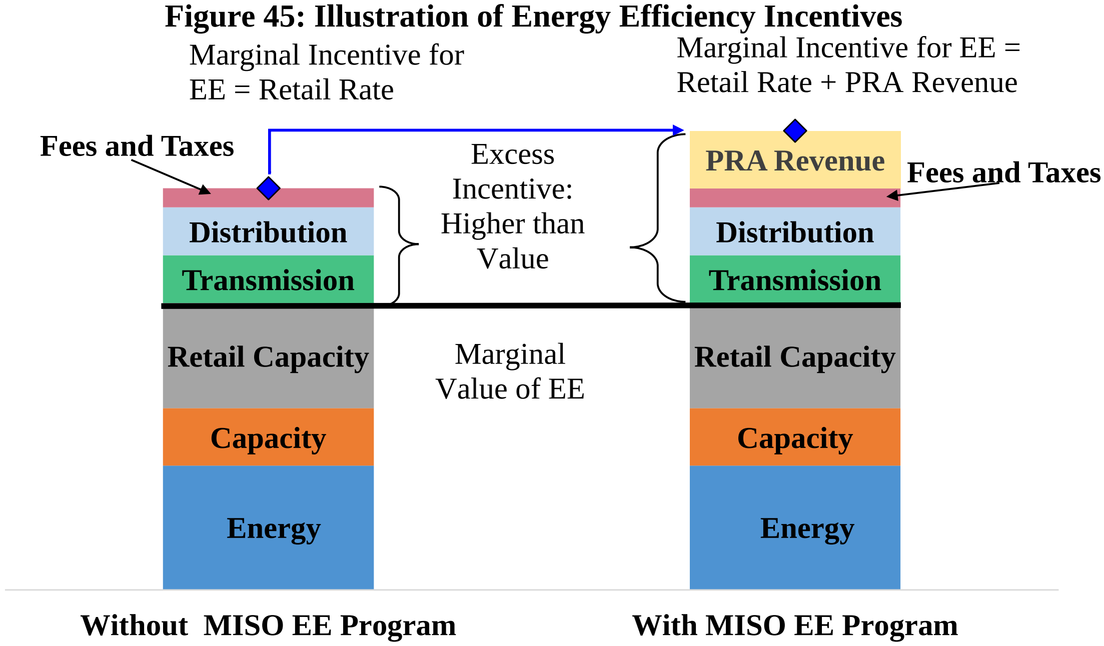
In contrast to other LMRs, EE measures do not provide a dispatchable product and do not provide any other operating flexibility to assist MISO in maintaining reliability during emergency events. Given the rapid increase in EE capacity, it is important that providing credits to EE is justified and that the accreditation of EE is accurate. Our evaluation raises concerns in both regards.

51 Beginning in the 2022-2023 PRA, LMRs that register with 6 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.

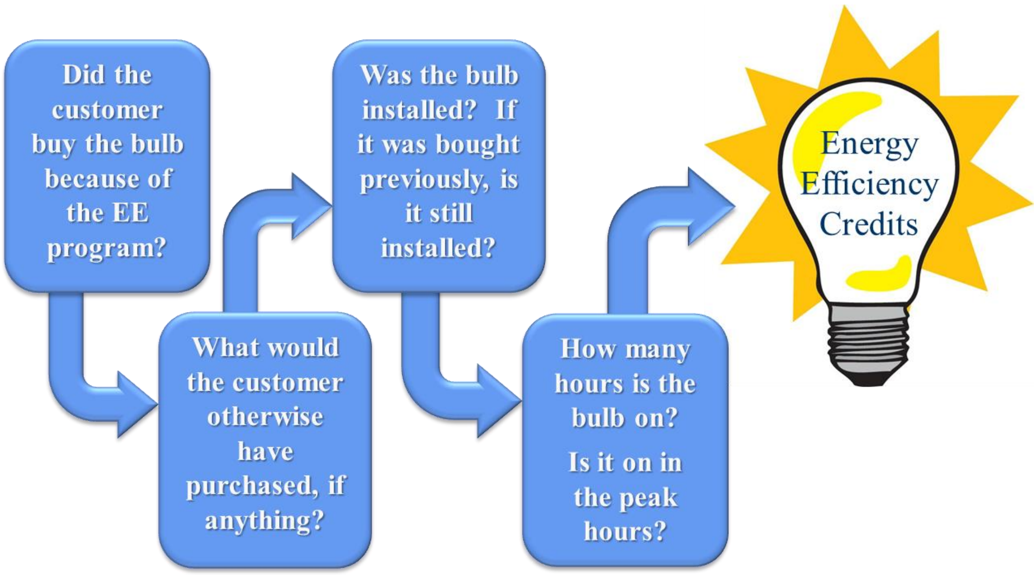
*Economic Justification for EE.* Making payments to customers directly or to intermediaries that facilitate EE investments is justified to the extent that such payments are efficient and lead to more economically efficient EE investments. Absent MISO's EE program, customers that reduce energy consumption by purchasing energy efficient technologies will receive savings via lower electricity bills. Some states provide a further incentive for such savings via tax credits and rebates. 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 capacity savings. Therefore, making capacity payments for assumed load reductions essentially double-compensates such customers and is, therefore, not efficient or necessary.

This is illustrated in Figure 45 below. The two columns compare the incentives for consumers to purchase EE, both with and without EE participation in MISO's capacity auction. This figure assumes that the PRA revenues are directly or indirectly paid to consumers to induce additional EE, although this is often not the case, as discussed below. Both columns show that the marginal value of EE to MISO is based on the energy, capacity, and retail capacity savings for peak load reduction. The incentive for consumers to invest in EE is represented by the blue diamonds, which is equal to the full retail rate. The left column shows that even without the PRA revenues, the incentive to invest in EE is higher than the value of the EE to MISO. The right column shows that making PRA revenues available to customers through the EE tariff increases the divergence between consumers' incentives and the true value of EE to the system.

**Figure 45: Illustration of Energy Efficiency Incentives**




*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 it can, the resulting capacity credits are unlikely to be accurate. To address this concern, 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 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 resource 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.
- Unlike the type of program illustrated above, the capacity payments were not used to provide meaningful incentives to customers increase the sales of EE products.
- The claimed savings were not reasonably verified as required under Attachment UU of the MISO Tariff.

These findings are unfortunate because MISO's customers paid more than $17 million to these resources and received nothing in return.

*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.

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.

# XI. Recommendations

Although MISO's markets continued to perform competitively and efficiently in 2020 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, 0 new.
- Operating Reserves and Guarantee Payments: 2 total, 1 new.
- Dispatch Efficiency and Real-Time Market Operations: 7 total, 2 new.
- Resource Adequacy: 9 total, 1 new.

Twenty-four 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 four 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. We also discuss one recommendation we removed that has not been fully resolved.

## 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.

### 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 late 2020, MISO and SPP agreed to modify M2M processes to address oscillations. This issue is being tracked on the Issue Tracking Tool under MSC014.

Next Steps: Continue to evaluate potential improvements and monitor the effectiveness of improvements that are implemented in the near term.

### 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.

Next Steps: MISO and SPP will resume these discussions in 2021 and consider the IMM M2M study recommendations. MISO should also initiate discussions with PJM to pursue comparable improvements for the M2M coordination with PJM.

### 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 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 of 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 that 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. MISO and the IMM have been working with TOs to promote voluntary development of AAR Programs, which may require development of new processes by MISO and the TOs. In 2020, MISO implemented changes to shorten the lead-time on adding AARs. MISO is scoping additional solutions under the MSE project, but no solutions have been prioritized for development.

Next Steps: MISO should complete its evaluation and scoping of improvements that can be implemented through the MSE project or through other means.

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

MISO currently employs a 1.5 percent generator shift factor cutoff 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. In most cases, this is a reasonable cutoff. However, there are some constraints where employing a

1.5 percent cutoff fails to engage most of the economic relief available to manage the constraint and, in some cases, raise reliability concerns. This can greatly increase the costs of managing the constraints and diminish reliability. In 2020, $53 million in congestion occurred on such constraints.

To improve the management of congestion on these constraints, we recommend that MISO implement the capability to reduce the GSF cutoff in the dispatch model for certain constraints. In addition to improving economic efficiency, this will also address some M2M settlement and FTR funding issues because the market flows calculated for M2M settlements and the FTR market do *not* employ a GSF cutoff. MISO's M2M coordination partners, PJM and SPP, have both eliminated their GSF cutoffs when dispatching and pricing coordinated flowgates. MISO could significantly reduce its costs on both M2M constraints and other constraints by reducing or eliminating its cutoff, at least on some constraints. Such changes should not affect the performance of its software.

Status: We continue to assign this a high priority because it would produce benefits that exceed most other roadmap items.[52] MISO currently has this prioritized as "low," but has indicated that it will continue to frame and evaluate this recommendation in 2021. MISO should complete its evaluation of this recommendation to allow it to prioritize this recommendation higher.

### 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 the 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

52 Lower Generation Shift Factor Cutoff for Constraints with Limited Relief, IR078.

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 level may seem very 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.[53] Stakeholder discussions regarding VOLL levels and scarcity pricing began in 2020. An evaluation whitepaper is expected in 2021.

Next Steps: MISO plans to complete an evaluation of improvements to the ORDC and VOLL, and to file any proposed enhancements with FERC in the first half of 2021.

### 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 2020, multiple simultaneous generation outages contributed to more than $225 million in real-time congestion costs—nearly 20 percent of real-time congestion costs.

Most of the other RTOs in the Eastern Interconnect have limited authority comparable to MISO's, with the exception of ISO-New England. The 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.[54] We recommend that MISO expand its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages.

Status: MISO has not sought additional outage coordination authority, and this is currently listed as Inactive in the Integrated Roadmap. Economic considerations for outage coordination continue to be in the RAN work plan, but the current target within MISO to start scoping is 2024.

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

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

54 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.

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

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 most 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 congestion cost savings of AARs of $66 and $61 million in 2019 and 2020, 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 $48 and $52 million in 2019 and 2020, respectively.

<u>Status</u>: In late 2020, FERC issued a notice of a proposed rule (NOPR) that included making Ambient-Adjusted Ratings a requirement.[55] MISO and the IMM continued to work with transmission owners to voluntarily provide AARs and emergency ratings, but progress was limited. The costs to implement such programs should be minimal because they should require very little additional telemetry and utilize existing systems and communications.

<u>Next Steps</u>: The IMM will continue to work with MISO and the TOs to implement AAR programs and solicit agreements from the TOs to provide emergency ratings.

### 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.

<u>Status</u>: 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 in MISO's

55 See Dockets No. RM20-16 and AD19-15 Managing Transmission Line Ratings.

Roadmap as a Parking Lot item pending performance enhancements expected from the MSE.[56] The IMM encourages MISO to reconsider this recommendation upon completion of the MSE.

### 2014-3: Improve external congestion related to TLRs by developing a JOA with TVA and IESO

As noted in prior years, the integration of MISO South has increased the frequency of TLRs called by TVA. In 2020, there were also a number of costly TLRs called by IESO, resulting in substantial curtailments of imports from PJM. These curtailments resulted in costly price spikes in MISO and were a very inefficient means to manage the constraints in IESO. Substantial benefits for MISO could be achieved by developing joint operating 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 met with both IESO and TVA to address these transmission-coordination and TLR issues in recent years. MISO has proposed a JOA to TVA that would allow MISO and TVA to provide economic redispatch under certain circumstances, but no agreement has been reached. MISO is also working to implement the Parallel Flow Visualization (PFV), which is targeted for the first quarter of 2022. Likewise, MISO has been actively working with IESO to develop procedures to ensure better coordination.

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 JOAs 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 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 with this recommendation but has not begun work to address the pricing issues at all of MISO's other interfaces, and it is currently inactive in the MISO

56 Introduce a Virtual Spread Product, IR005.

Roadmap. We continue to recommend that MISO take any necessary steps to remove external congestion from its interface prices at all other interfaces. 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 has indicated this topic will be reviewed in the Seams Management Working Group in the first Quarter of 2021, and MISO will develop the workplan necessary to modify its interface prices as part of its Market Systems Enhancement.

## 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 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.

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

We recommend that 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.

We recommend MISO consider this effort in two timeframes. First, we recommend MISO establish a real-time capacity product or uncertainty product that would be implemented under MISO's current market software. In the longer term, we recommend that MISO consider implementing this product along with its existing products through a look-ahead dispatch (LAD) model that would optimize the dispatch of resources in future periods of up to four hours.

Status: This is a new recommendation.

### 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 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. MISO is currently discussing a revised RDT Agreement with SPP and the Joint Parties and this proposal is included in these discussions.

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.

### 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 needs of the systems. 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 where MISO declared a capacity emergency during Hurricane Laura on August 27, 2020 that resulted in load shedding and prices being set at VOLL ($3,500 per MWh). This outcome was efficient because the decision not to serve the load was on the margin during this period so prices should reflect the value of the load not served. In contrast, MISO declared a transmission emergency during the Arctic Event on February 15-16, 2021 and shed load in the same load pocket after losing 1,300 MW of generation in the pocket. This resulted in prices well below VOLL. As a result, the market-based charges to the generators that tripped and caused the emergency were $23 million less than under VOLL pricing and compensation to the loads in the pocket was $29 million less.[57] We find these results to be inefficient and a substantial concern. To bring alignment between the two types of emergencies, we recommend that MISO:

1. Review 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. Raise 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, MISO may increase the Post Reserve Deployment Constraint Demand Curves to achieve efficient local emergency pricing.

Status: This is a new recommendation.

### 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: This is a new recommendation.

57 For details on the event, see the IMM Winter 2021 Quarterly Report.

### 2019-4: Clear CTS transactions every five minutes through the UDS based on the RTOs' most recent five-minute prices.

We have also 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 $12 million, which are much larger than can be achieved by improving the current process.

Status: MISO agrees that poor forecast accuracy has been a problem and that use of the most recent five-minute prices could facilitate more efficient interchange adjustments. Given other priorities and the dependency on MSE, MISO is not prioritizing this recommendation in 2021.

Next Steps: We 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 has worked with the IMM to revise the emergency procedures. MISO is working with the IMM to improve its processes and procedures, including a multi-phase project to improve its Capacity Sufficiency Analysis Tools.

Next Steps: Continue to work together to improve the clarity of the procedures and the tools used to trigger the declarations of varying levels and types of emergencies.

### 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, but 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.

<u>Status</u>: MISO agrees that CTS has not performed well and that the charges are a factor. However, MISO favors addressing other factors, including reducing the forecasting errors. This item (IR066) was placed in the Integrated Roadmap Parking Lot in 2018 and continues to be Inactive in 2021. We believe this is a poor decision because the CTS process will not be effective unless the current charges are eliminated.

<u>Next Steps</u>: 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, others 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 that MISO upgrade its systems and procedures to allow these and other operator actions to be logged in a more complete and detailed manner.

Status: In 2020, MISO improved logging features within the current MCS. Training for operators will facilitate more clear and concise log entries. 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.

Next Steps: MISO and IMM staff will continue to work on identifying additional logging needs. In 2021, MISO will continue work on a more detailed and integrated solution through the MCS.

### 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 procedures and logging processes to record operator decisions to respond to the LAC recommendations.

Status: MISO generally agrees with this recommendation. In 2018, MISO implemented tools that support the review of LAC recommendations by the operators.

Next Steps: MISO indicates it will continue to investigate sources of inaccuracies in 2021 that can be resolved in the near term and inform the development of a long-term LAC improvement plan. Once it 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 economic signals from the MISO markets will be increasingly important as planning reserve margins in MISO fall. 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: This is a new recommendation, but we have discussed it with MISO and has MISO begun an initial evaluation.

### 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 that 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.

Next Steps: MISO should work with its stakeholders and the IMM to complete its evaluation and prioritize this recommendation in light of recent findings.

### 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. Generating resources are currently qualified to sell capacity based on their forced outage performance, which is considered in the calculation of their UCAP levels. Under MISO's existing capacity accreditation construct, resource UCAP values are determined by discounting resource total installed capacity using forced outages that participants self-report to GADS.[58] This is problematic because:

- Other types of outages and derates also reduce MISO's access to capacity resources and result in the same reliability impacts as forced outages;
- Suppliers do not completely report their outages and derates;
- Less reliable resources that are rarely needed are credited as fully available when they are not asked to run, inflating their UCAP levels; and
- Long-lead time resources that are frequently offline provide far less value than their UCAP level because when tight conditions arise unexpectedly, they cannot be utilized.

Therefore, we recommend 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.

These changes would result in sizable accreditation improvements by causing the accreditation to reflect the relative reliability contribution of each resource. This is important because tight conditions in the future will increasingly be caused by uncertainty related to intermittent output and other factors. This recommendation will reward the flexible resources that allow MISO maintain reliability in the face of this uncertainty.

Status: In 2020 and early 2021, this topic was discussed extensively at MISO stakeholder meetings and is in scope for a planned filing in 2021.[59] Addressing this issue is one of the primary goals of the RAN process.

Next Steps: We will continue to work with MISO to complete the development of these proposed accreditation improvements and anticipate a FERC filing in 2021.

### 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. We recommend improvements in three areas:

1. Planning Resources deduct both station service loads (associated with the power generation equipment) and process loads (typically industrial loads, including both heat and power) from their installed capacity levels. Unlike station service loads, the process

58 Exceptions exists for LMRs that receive additional capacity credit associated with the PRMR value and transmission losses, and intermittent resources whose accreditation is based on the ELCC methodology.

59 See RAN Reliability Requirements and Sub-annual construct (RASC010-12).

loads may continue when the generator is out of service and must be served along with MISO's other firm load, which should be recognized in the capacity requirements.

2. Some of the assumptions in MISO's planning model are not consistent with reality, such as the assumption that generators not on forced outage will be fully available. We recommend that MISO review these assumptions.
3. We have identified a number of areas where erroneous data has been submitted by suppliers, resulting in sizable accreditation inaccuracies. These errors have included: temperature and humidity corrections to Generator Verification Tested Capacity (GVTC) test data, GVTC adjustments for process loads of CHP facilities, and simultaneous capabilities of generation equipment during peak conditions. We recommend that MISO improve its validation of such data.

Status:

1. MISO recommends clarifying the BPM-011 language to specify what level of firm process load should be reported by Generator Owners when submitting GVTC data. This topic was presented to the RASC in 2020 to begin to evaluate options and identify a sufficient solution.
2. MISO has been collaborating with the IMM and stakeholders to improve planned outage assumptions in its LOLE model. The refined planned outage modeling has been implemented in the planning year 2021–2022 LOLE analysis to determine the Planning Reserve Margin and is working to implement an optimized outage methodology in the 2022–2023 PY LOLE study for the zonal Local Reliability Requirements.
3. MISO has addressed the validation portion of this recommendation. MISO now has the staff, tools, and processes in place to validate the GVTC corrections.

Next Steps: Work to address items 1 and 2 through the RAN initiative. Item 3 is complete.

### 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. MISO continued to discuss this recommendation in 2020 and early 2021 with stakeholders and the IMM. This recommendation has been aligned with IR025 (sub issue RASC009) and is deemed to be a high priority by MISO.

Next Steps: MISO should address this recommendation as a component of the availability-based accreditation proposal currently under development by MISO.

### 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.

### 2014-5: 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. This would produce the following benefits:

- The revenues would be better aligned with the value of the capacity;
- Relatively high-cost resources would have an opportunity to achieve savings by taking seasonal outages during shoulder seasons;
- The qualification of resources with extended outages can better match their availability;

- Resources retiring mid-year would have more flexibility to retire mid-year without having to procure significant replacement capacity to satisfy post-retirement capacity obligations; and
- The duration of SSR contracts can be matched with planning seasons, which removes a barrier for SSR Units to serve as Planning Resources.

To capture these benefits, we recommend that MISO consider at least a four-season approach and implement seasonal auctions prior to each season to complement an annual auction.

Status: This recommendation is partially aligned with the MISO's RAN Initiative and is being considered as part of RAN Phase 3. MISO has begun the conceptual design for an annual four-season auction and is discussing these options with the Resource Adequacy Subcommittee. MISO is not currently considering conducting a prompt seasonal auction prior to each season. The basis for this decision is not clear, because doing so would not be costly and would allow the initiative to produce greater benefits by allowing the seasonal prices to accurately reflect the supply and demand in season.

Next Steps: MISO is tentatively targeting a FERC filing in 2021 for potential resource adequacy construct changes. This item is aligned with RASC011 and is a sub-issue of RAN initiative.

#### 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: Evaluate the benefits of improving the zonal 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 fall toward the minimum requirement. This is particularly harmful as large quantities of resources are facing the decision to retire in response to prevailing market conditions.

A sloped demand curve 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 a particular problem for competitive retailers, municipal utilities, and competitive generators that rely on the market to retain adequate resources to ensure reliability. In 2016, MISO developed a proposal to improve capacity pricing in CRAs that FERC ultimately rejected. We offered an alternative proposal that would have utilized a sloped demand curve to set prices for competitive suppliers and loads. If a sloped demand curve cannot be implemented for all participants in the PRA, we recommend MISO pursue our alternative.

Status: This recommendation remains in inactive status. MISO is not in agreement on this issue because it lacks support among the states.

Next Steps: MISO should continue to work with its stakeholders and OMS to move toward a consensus on the recommendation.

## E. Recommendations Addressed by MISO or Otherwise Removed in 2020

MISO addressed several past recommendations in 2020 and early 2021, which are discussed in this subsection along with unresolved recommendations not included in this year's report.

***Recommendations Addressed by MISO***

### 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.

### 2017-6: Require the ICAP of Planning Resources be deliverable

The Tariff requires that all types of resources be deliverable to load in order to be eligible to be capacity resources. Deliverability is determined by, among other things, demonstrating Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS) coupled with firm transmission reservations. However, MISO had not implemented its deliverability requirements in a manner that is comparable for the NRIS and ERIS resources.

We had recommended that MISO determine deliverability for all resources based on the entire ICAP of conventional planning resources (whether they are NRIS or ERIS resources). MISO filed Tariff changes to address this recommendation that were approved late in 2020.[60] MISO is implementing the processes needed to adopt the new rules in time for the 2021/2022 PRA.

### 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.

### 2010-11: Incorporate expected deployment costs into the selection criteria when clearing reserve products

The MISO ancillary services market does not consider the expected costs of deployment when clearing reserve products; rather, the availability offer is the only economic consideration. When deployed, reserve providers may be eligible for Price Volatility Make-Whole Payments or RSG payments that cover start-up, hourly and incremental energy costs. Ignoring these costs resulted in an inefficient selection of reserve providers. We recommended that MISO factor in the expected costs of deployment into the scheduling process in order to improve the efficiency of

60 Docket ER20-1942-000 and Docket ER20-2005-000.

reserve schedules and reduce uplift costs. One way to accomplish this is to remove eligibility for these make-whole payments when reserves are deployed, which would cause the suppliers to incorporate these expected deployment costs in their reserve offers. MISO responded to this recommendation by removing deployed spinning reserves volumes from make-whole payment calculations. _MISO filed this proposed change with FERC in late 2020.[61] FERC approved this filing and this market design change will be effective on June 1, 2021.

***Removed Recommendation***

The following is a previous recommendation that has been removed as an active IMM recommendation. This may be revived at a later time if circumstances warrant.

### 2017-5: Evaluate the feasibility of implementing a 15-minute day-ahead market under the Market System Enhancement

MISO's hourly day-ahead market is incongruent with the real-time dispatch that runs every five minutes. A more granular day-ahead market would better schedule resources and prepare the system to satisfy the real-time system needs. We recommended MISO evaluate the feasibility of this improvement through its MSE project. MISO agreed with the recommendation but plans to defer this evaluation until after MSE delivery. We are removing this recommendation because it is likely no longer feasible but may revive it once MSE is implemented.

61 Docket ER21-679-000.