# 2018 State of the Market Report for the MISO Electricity Markets

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**for the Midcontinent ISO**

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## Guide to Acronyms

| | |
|---|---|
| AMP | Automated Mitigation Procedures |
| ARC | Aggregators of Retail Customers |
| ARR | Auction Revenue Rights |
| ASM | Ancillary Services Markets |
| BCA | Broad Constrained Area |
| BTMG | Behind-The-Meter Generation |
| CDD | Cooling Degree Days |
| CMC | Constraint Management Charge |
| CONE | Cost of New Entry |
| CRA | Competitive Retail Area |
| CROW | Control Room Operating Window |
| CSAPR | Cross-State Air Pollution Rule |
| CTS | Coordinated Transaction Scheduling |
| DAMAP | Day-Ahead Margin Assurance Pmt. |
| DDC | DA Deviation & Headroom Chrg. |
| 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 |
| EPA | Environmental Protection Agency |
| FERC | Federal Energy Reg. Commission |
| FFE | Firm Flow Entitlement |
| FTR | Financial Transmission Rights |
| GSF | Generation Shift Factors |
| HDD | Heating Degree Day |
| HHI | Herfindahl-Hirschman Index |
| IESO | Ontario Electricity System Operator |
| IMM | Independent Market Monitor |
| ISO-NE | ISO New England, Inc. |
| JCM | Joint and Common Market |
| JOA | Joint Operating Agreement |
| LAC | Look-Ahead Commitment |
| LAD | Look-Ahead Dispatch |
| LMP | Locational Marginal Price |
| LSE | Load-Serving Entity |
| M2M | Market-to-Market |
| MATS | Mercury and Air Toxics Standards |
| MCP | Marginal Clearing Price |
| MISO | Midcontinent Independent Tx Sys. Operator |
| MMBtu | Million British thermal units |
| MSC | MISO Market Subcommittee |
| MTLF | Mid-Term Load Forecast |
| MVL | Marginal Value Limit |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NCA | Narrow Constrained Area |
| NDL | Notification Deadline |
| NERC | North American Electric Reliability Corp. |
| NSI | Net Scheduled Interchange |
| NYISO | New York Independent System Operator |
| ORCA | Operations Reliability Coordination Agmt. |
| ORDC | Operating Reserve Demand Curve |
| PJM | PJM Interconnection, Inc. |
| PRA | Planning Resource Auction |
| PVMWP | Price Volatility Make Whole Payment |
| RAC | Resource Adequacy Construct |
| RCF | Reciprocal Coordinated Flowgate |
| RDI | Residual Demand Index |
| RDT | Regional Directional Transfer |
| RGD | Regional Generation Dispatcher |
| RSG | Revenue Sufficiency Guarantee |
| 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 |
| SRPBC | Sub Regional Power Balance Constraint |
| SSR | System Support Resource |
| STLF | Short-Term Load Forecast |
| TCDC | Transmission Constraint Demand Curve |
| TLR | Transmission Line Loading Relief |
| VLR | Voltage and Local Reliability |
| 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 *2018 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 and 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.

## Market Outcomes and Competitive Performance in 2018

The MISO energy and ancillary services markets generally performed competitively in 2018. The most notable factor affecting market outcomes in 2018 was the increase in natural gas prices from historically low levels in recent years. The four percent increase in natural gas prices from 2017 and higher average load led to an eight-percent increase in energy prices throughout MISO, which averaged $32 per MWh in 2018.

Prices often varied substantially throughout MISO in 2018, reflecting congestion on the MISO transmission network. The value of real-time congestion fell by 6.8 percent to $1.4 billion, driven in part by key transmission upgrades and improvements in market-to-market ("M2M") coordination. Nonetheless, the real-time congestion that occurred in 2018 is higher than optimal because several key issues continue to encumber congestion management in MISO, including:

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

To address these concerns, we recommend a number of improvements to lower the cost of managing congestion on MISO's system.

### *Competitive Performance and Market Design Improvements in 2018*

The MISO markets continue to exhibit a consistent overall relationship between energy and natural gas prices. This is expected in a well-functioning, competitive market. Natural gas-fired resources are frequently 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 also evaluate the competitive performance of the MISO markets by assessing the conduct of its suppliers, which was broadly consistent with expectations for a workably competitive market. This is indicated by 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 2018. This indicates that the MISO markets were highly competitive in 2018.

- The "output gap" is a measure of potential economic withholding. It remained unchanged from 2017, averaging 0.1 percent of load, which is *de minimus*. Consequently, market power mitigation measures were applied infrequently.

MISO implemented several market design changes in 2018 that were intended to improve the efficiency and competitiveness of the MISO markets.

- On January 4, FERC granted MISO the authority to define Dynamic Narrow Constrained Areas (DNCAs) consistent with our SOM Recommendation 2012-9.

- On July 1, MISO implemented five-minute real-time settlements consistent with our SOM Recommendation 2012-2.

- On August 22, MISO created a new operating guide for MISO South to commit to N-2 in an area with few quick-start resources.

- On August 23, FERC granted MISO Reserve Sufficiency Guarantee (RSG) mitigation authority for resources committed in MISO South for the Regional Directional Transfer

(RDT) constraint and granted MISO the authority to apply the Reserve Procurement Enhancement (RPE) to the RDT.

- In October, MISO filed to reform uninstructed deviation and related make-whole payment rules which FERC approved and were implemented in May 2019.
- In December 2018, MISO filed Tariff changes as part of the Resource Availability and Need (RAN) efforts that would allow MISO to schedule LMRs outside of the summer months and also in anticipation of emergencies if the LMRs have long lead times. FERC accepted this filing in February 2019.
- Also in December 2018, MISO filed separate RAN-related Tariff changes that were accepted by FERC in March 2019 requiring Demand Response (DR) resources to conduct testing to provide more accurate curtailment information to MISO.

***Emergency Events in 2018***

Over the past few years, MISO has experienced a significant increase in the frequency and severity of generation emergencies. MISO declared three emergencies in 2018, and two emergencies on consecutive days in early 2019.

- *January 17, 2018*: Unusually cold weather in MISO South caused a record winter peak load in the South of 32.1 GW and high levels of forced outages, which resulted in emergency conditions. On January 17, MISO declared an Emergency Event Step 2 after a capacity deficiency occurred, which resulted in MISO exceeding the RDT limit for roughly one hour, making emergency purchases from other areas, and scheduling LMRs.
- *January 18, 2018*: As a continuation from emergency events the prior day, MISO declared an Emergency Event Step 2 to utilize emergency generation ranges, offline emergency generators, and LMRs to address high load and uncertainty regarding generation availability.
- *September 15, 2018*: On the evening of September 14, MISO lost the largest single contingency in MISO South, a 1,400 MW nuclear unit. The day-ahead market procurements and the day-ahead load forecast for September 15 were both significantly below the actual real-time load because temperatures were higher than expected. MISO issued a Maximum Generation Event Step 2, allowing it to access emergency generation ranges, offline emergency generators, LMRs, and emergency transactions.
- *January 30, 2019*: MISO issued a Maximum Generation Event Step 2 in the North and Central regions because extremely cold weather resulted in a sharp decline in wind output relative to the day-ahead forecast, issues with transmission elements (circuit breakers) impacted by arctic conditions, and uncertainty regarding forced outages that may result from the cold temperatures.

- *January 31, 2019*: MISO downgraded the January 30 event to Emergency Event Step 1 that was extended through noon on January 31 to allow it to access emergency generation ranges and offline emergency generators. The extension was attributable to the extreme temperatures and uncertainty regarding whether units could restart if decommitted.

During four of these events, MISO scheduled LMRs, but the LMRs available to the market were limited by long notification times. On two of these occasions, MISO employed more extensive emergency procedures, including buying emergency power from its neighbors.

All of these events were regional events where the primary concern would be violating the RDT flow limit if system contingencies were to occur. These types of emergencies are relatively new, having not occurred prior to 2016. Based on our review of these events, which is provided in Section III, we find that MISO's emergency declarations and actions were 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.

## Long-Term Economic Signals and Resource Adequacy

### *Capacity Levels and Summer Capacity Margins*

MISO had 4 GW of resource retire in 2018, roughly two-thirds of which were coal-fired resources in the Midwest. MISO added 1.8 GW of new resources. Three quarters of the new generation was wind, which provides substantially lower reliability value per MW than the retiring resources because of their intermittent nature. Based on the capacity market design concerns we discuss in this report, we expect the 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 2019 if the peak conditions are not substantially hotter than normal. In the long-term, however, we are very concerned about the adequacy of MISO's resources. 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 2018. We find:

- Net revenues continue 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");
- Net revenues for a number of the existing resources are less than necessary to cover their going forward costs, providing economic incentives to retire these units;
- Low natural gas prices have led to low energy prices, which have disproportionately affected the net revenues of non-gas-fired resources, most notably nuclear units; and

- Compared to 2017, combustion turbine net revenues fell at all locations with the exception of Louisiana where significant congestion contributed to higher net revenues, and combined cycle net revenues grew slightly at all locations except Texas.

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 because of retirements and units exporting capacity to PJM. These issues are summarized in the following section.

### *PRA Results and Design*

MISO administers a Planning Resource Auction (PRA) to allow its participants to buy and sell capacity at various locations 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 local 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 over the past two years:

- In the 2018-2019 PRA, changes in the capacity requirement and supply curve contributed to a footprint-wide clearing price in unconstrained zones of $10 per MW-day and $1 per MW-day in Zone 1, which was export-constrained.

- In the 2019-2020 PRA, lower capacity requirements and the establishment of external zones contributed to a MISO-wide clearing price of $2.99 per MW-day in unconstrained zones and $24.30 per MW-day in Zone 7, which was constrained by the Local Clearing Requirement.

The low clearing prices 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. This effectively 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 resources that are 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. Because most of their planning needs are self-supplied, however, the effects on the regulated participants of improving the demand curve is much smaller than the effects on competitive loads and competitive suppliers. These competitive participants rely on economic market signals to guide their long-term investment and retirement decisions. Hence, it would be reasonable to adopt a two-stage PRA design that would establish efficient prices and settlements for competitive participants.

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:

- Limiting emergency-only resources to participate in the capacity market only if they are able to be available within a reasonable amount of time during an emergency.
- Validating the accuracy of data submitted by participants that affect the accreditation of resources.
- Reforming resource accreditation to better reflect the reliability value of resources by recognizing all outages and derates, including those that are not reported, during tight conditions.
- Procuring capacity to serve all firm load, including behind-the-meter firm process load.

Other improvements we recommend that do not specifically involve the supply or demand for capacity in the PRA include:

- Transitioning to a seasonal capacity market.
- Improving the modeling of transmission constraints in the PRA.

A number of these recommendations are likely to be addressed through MISO's RAN initiative, which is discussed in the Recommendation section of the report.

## 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 2018*

The value of real-time congestion fell by 6.8 percent from last year to $1.4 billion. Congestion tends to track natural gas prices because natural gas-fired units are generally dispatched to manage the power flows over binding constraints. Although natural gas prices rose in 2018 relative to 2017, congestion fell in three quarters of the year. Lower natural gas prices and outages in the spring compared to 2017 contributed to the reduction in congestion. In addition, transmission upgrades and improvements in the market-to-market coordination process contributed to the lower congestion.

Not all of the $1.4 billion in real-time congestion is collected by MISO through its markets, primarily because there are loop flows caused by others and flow entitlements granted to PJM, SPP, and TVA which do not pay MISO for use of the network. Hence, day-ahead congestion costs totaled $700 million in 2018, down 6 percent from last year.

These day-ahead congestion costs 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 – which was the case in 2018. This is good because under-funding FTRs degrades the value of the FTRs and ultimately, this harms transmission customers when they receive reduced revenues from the sale of the FTRs.

There are many MISO constraints that are greatly affected by generation in PJM and SPP, and there are constraints in these areas that are affected by MISO generation. Therefore, MISO coordinates the management of congestion on these constraints through the market-to-market process with SPP and PJM. Congestion on MISO's market-to-market constraints rose 9 percent in 2018 to $508 million, which is more than a third 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 market-to-market coordination operate as effectively as possible.

***Congestion Management Concerns and Potential Improvements***

Although improvements have been made overall, we remain concerned about a number of issues that undermine the efficiency of MISO's management of transmission congestion, including:

- *Market-to-Market Coordination.* We identified 36 constraints in 2018 that were not defined as market-to-market constraints but should have been defined. This is significantly lower than the 160 constraints in 2017. Congestion associated with these undefined constraints fell from more than $240 million in 2017 to $68 million in 2018.
- *Outage Coordination.* Transmission and generation outages often occur simultaneously that affect the same constraint. Roughly $350 million – almost 25 percent of all of real-time congestion – occurred on constraints affected by multiple generation outages. This underscores the importance of improving MISO's authority to coordinate outages.
- *Pseudo-Tied Resources.* PJM has taken dispatch control of increasing numbers of MISO generators via pseudo-ties -- 59 new market-to-market constraints in MISO have been defined because of the MISO units that have been pseudo-tied to PJM. In 2018,

congestion costs on these constraints was $25 million, significantly higher than the congestion costs they exhibited prior to the pseudo-ties.

- *Improved Transmission Ratings.* Most transmission owners do not actively adjust their facility ratings to reflect ambient temperatures and wind speeds. As a result, MISO uses more conservative seasonal ratings, which reduces MISO's utilization of the true network capability. We estimate MISO could have saved more than $145 million in production costs in 2018 by using temperature-adjusted and short-term emergency ratings. This supports continued efforts with transmission owners to receive and use these ratings.
- *Reduce the GSF Cutoff for Constraints with Limited Relief*. 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 its market software. While this is generally reasonable, it excludes valuable congestion relief on some constraints – generally low-voltage and M2M constraints. This can adversely affect reliability, increase M2M settlement costs, and lead to FTR shortfalls and surpluses. Our analysis shows $70 million of incremental economic relief would be available if the GSF cutoff were reduced to 0.5 percent on a limited number of constraints.

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.

## 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 2018:

- The difference between day-ahead and real-time prices was 0.6 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. Cleared virtual transactions rose 11 percent in 2018 to average more than 15 GW per hour. Our evaluation of virtual transactions revealed:

- More than 90 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 a 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 very important 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 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 prices were competitive in 2018, as indicated above, rising eight percent relative to 2017.

### *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 practices. 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, which 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 – we recommend MISO introduce an efficient ORDC as described in Section V.C.; and
- The shortage pricing is undermined by allowing offline resources to set prices in the ELMP model and we recommend that MISO disable its offline resource pricing.

Improving MISO's shortage pricing is essential because it will align shortage pricing with the marginal reliability value of the foregone reserves. This will result in more efficient economic signals that govern both short-term and long-term decisions by MISO's participants.

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 current ELMP model, however, shows that it has not been very effective.[1] It has raised real-time prices by an average of only $0.72 per MWh. With limited changes to the resource eligibility and one key assumption, we estimate that ELMP would have increased real-time prices by more than $2.75 per MWh. In high-load hours when reliance on peaking units is relatively higher, 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. We believe these improvements should be a high priority.

### *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 recommended that MISO introduce a 30-minute reserve product for each region. MISO will be filing this "Short-Term Reserve" product in 2019 and it will likely be implemented in 2021.

When higher levels of interregional transfers do not contribute to congestion on the Joint Parties' systems, incurring substantial costs to limit the transfers can be inefficient. To reduce these inefficient costs in managing the transfers using the RDT, we recommend that MISO allow the Joint Parties to sell operating reserves with the transmission capacity on the RDT (above the RDT limit). MISO could then compensate the Joint Parties by paying them the clearing price for subregional reserves, as well as paying for the deployment of the reserved transmission (equal to the $500 per MW RDT demand curve level times the deployment quantity). Under this approach, the Joint Parties would have been compensated $3.25 million during the emergency events that occurred on January 17-18, 2018. This payment is reasonable compensation for the excess transfers that may occur under emergency conditions.

### *Real-Time Generator Performance*

A substantial concern we evaluate is the poor performance of some generators in following MISO's dispatch instructions. 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 180 MW in hours when generators are generally ramping up and more than 500 MW in the worst 10 percent of these periods. This continues to raise substantial economic and reliability concerns because these deviations were often not detected by MISO's operators.

[1] This evaluation is described in Section V.B.

We previously recommended that MISO develop better uninstructed deviation thresholds and improved price volatility make-whole payment formulas to improve incentives for generators to follow dispatch signals. MISO filed these changes in October and they were approved by FERC and implemented in May 2019. We continue to recommend that MISO work to improve generator performance. In 2017, we developed an alert that is sent to MISO operators when sustained generator deviations occur to allow MISO to address such deviations.

### *Wind Overforecasting*

We determined that average deviations by wind units are larger than any other class of resource. These deviations occur because some wind units tend to significantly overforecast their output. The forecast is used by MISO to set wind units' dispatch maximum and, because their offer prices are low, the forecast also tends to set their dispatch level. These results raise concerns because they undermine MISO's dispatch efficiency and have led to unjustified payments to the wind resources. The wind deviations contributed to higher congestion and under-utilization of the network, supply and demand imbalances, and caused non-wind resources to be dispatched at inefficient output levels. In evaluating the causes for the forecast errors, we found that:

- Wind resources in MISO have a strong incentive to overforecast their output because the settlements for Excessive Energy (incurred when they underforecast) are far more punitive than the Deficient Energy settlements (incurred when they overforecast); and
- DAMAP settlement rules allowed wind resources to earn more revenue by deliberately overforecasting their output than by forecasting accurately. The wind resources were only eligible for these DAMAP revenues because of the flaw in MISO's Tariff that was corrected with the introduction of five-minute settlements in the third quarter of 2018.

Hence, we recommended a number of changes to the deviation thresholds, excessive and deficient energy settlement rules, and DAMAP rules to provide incentives for wind resources to forecast their output accurately. MISO filed these changes and they were implemented in May 2019. We are also recommending that MISO validate the market-participant-submitted forecasts in real time and that MISO address sustained errors when it produces its real-time dispatch.

### *Uplift Costs*

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

- Real-time RSG increased by 26 percent to $6.7 million per month.
- Day-ahead RSG fell by 2 percent to $3.3 million per month. Almost half of this RSG was associated with Voltage and Local Reliability (VLR) commitments in MISO South.

RSG payments associated with commitments made to maintain enough online capacity in the South to prevent exceeding the RDT limit after a major contingency is effectively a procurement of a 30-minute reserve requirement. These RSG payments fell in 2018. In August 2018, FERC granted MISO mitigation authority for resources committed in MISO South for the RDT. Several units were mitigated in the first few months following the Tariff change.

We recommended that MISO develop a 30-minute sub-regional reserve product consistent with the operating requirements described above. MISO is working on such a product (its Short-Term Reserve product) and is targeting implementation in late 2021. In the meantime, MISO applied its Reserve Procurement Enhancement (RPE) to the RDT in August 2018. This holds 10-minute reserves in the South as a proxy for these operating requirements.

#### *Pseudo-Ties to PJM and Real-Time Dispatch Concerns*

Because MISO's market does not establish efficient capacity prices, suppliers with uncommitted capacity have been exporting their capacity to PJM in increasing quantities. This has raised substantial operational concerns because PJM requires these units to be "pseudo-tied" to PJM. Because they affect power flows over numerous constraints on MISO's network, losing dispatch control of the units undermines MISO's dispatch and its ability to manage congestion efficiently. Our analysis shows that quarterly congestion on the constraints affected by these units has increased by 95 percent on average from before the pseudo-ties were implemented.

The effects of these pseudo-tied units have to be managed under the M2M coordination process with PJM. This is problematic, because not all of the constraints that were affected by pseudo-tied resources have been redefined as M2M constraints. In 2017, we filed a 206 complaint with the Commission to protest PJM's pseudo-tie requirement for external capacity resources. If FERC grants this complaint or PJM is willing to relinquish this requirement, we recommend that MISO implement firm capacity delivery procedures with PJM in lieu of pseudo-tying. These procedures would guarantee the delivery of the energy from PJM capacity resources in MISO, while maintaining the efficiency and reliability of MISO's dispatch.

## External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2017, importing an average of 6.3 GW per hour in real time. MISO remained a net importer of energy from PJM in 2017, with imports averaging roughly 2 GW per hour. Price differences between MISO and neighboring areas create incentives to schedule imports and exports between areas. Because of this key role of interface prices in scheduling imports and exports, 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"). In response to a concern we first raised in 2012 regarding the pricing of congestion in the PJM and

MISO interface prices, MISO agreed to adopt a new definition for the PJM interface in June 2017. This "Common Interface" 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. Ultimately, we continue to recommend that MISO implement an efficient interface pricing framework by:

- Removing all external constraints from its interface prices (i.e., include only MISO constraints), and
- Adopting accurate assumptions regarding where imports source and exports sink when calculating interface congestion.

*Interchange Coordination*. Coordinated Transaction Scheduling (CTS) is the most promising means to improve interchange coordination, which 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.

Unfortunately, there has been virtually no participation in CTS because of the charges and fees imposed by MISO and PJM, and because of significant forecasting errors that increase CTS risks for participants. MISO's transmission reservation fees (charged to all CTS offers) result in average costs per cleared MWh ranging from roughly $6.16 per MWh on exports to $2.15 per MWh on imports. These fees make participation in the CTS process irrational. Hence, we continue to recommend that both MISO and PJM eliminate these charges. We encourage MISO to do this unilaterally even if PJM does not agree to eliminate its charges.

### Demand Response

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 is continuing to seek to expand its DR capability. This includes efforts to allow for Batch Load DR and Price Responsive Demand. Currently, MISO has roughly 13 GW of DR resources, which includes 4.5 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. Ninety percent of MISO's DR resources are capacity resources or LMRs that can only be accessed after MISO has declared an emergency.

MISO has been working with its Load Serving Entities to improve accessibility and real-time information on the availability of LMRs. In December 2018, MISO filed two Tariff changes to expand MISO's access to LMRs and require additional testing of demand response resources. In early 2019, FERC approved these changes so MISO may now schedule LMRs in anticipation of an emergency event to access longer-lead resources. In addition to this improvement, we have recommended a number of other changes related to the integration of LMRs in MISO's markets.

Finally, we evaluate the availability of DR and other emergency resources during emergency events in which LMRs were called between April 4, 2017 and January 30, 2019. Since LMRs may have notification times up to 12 hours, their accessibility depends on how far in advance MISO recognizes and declares the emergency. These notification times have prevented MISO from being able to utilize the vast majority of the available LMRs during most of the emergencies. However, because of MISO's recent Tariff changes, 63 percent of LMRs that cleared the 2019-2020 PRA are now able to be scheduled within two hours, which should increase MISO's access to them. Nonetheless, we continue to recommend that MISO revisit the rules it uses to accredit all emergency resources that provide unforced capacity under Module E.

## Table of Recommendations

Although the markets performed competitively in 2018, we make 29 recommendations in this report intended to further improve their performance. Six are new this year, while 23 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 in 2018 and early 2019, as discussed in Section X.F. 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** | | | |
| **2018-1** | Improve emergency pricing by establishing an efficient default floor and accurately accounting for emergency imports. | ✓ | |
| **2018-2** | Lower GSF cutoff for constraints with limited relief. | | |
| **2017-1** | Improve the market power mitigation rules. | | ✓ |
| **2017-2** | Remove transmission charges from CTS transactions. | ✓ | ✓ |
| **2016-3** | Enhance authority to coordinate transmission and generation planned outages. | | |
| **2016-1** | Improve shortage pricing by adopting an improved operating reserve demand curve reflecting the expected value of lost load. | ✓ | ✓ |
| **2015-2** | Expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities. | ✓ | |
| **2015-1** | Expand eligibility for online resources to set prices in ELMP and suspend pricing by offline resources. | ✓ | ✓ |
| **2014-3** | Improve external congestion related to TLRs by developing a JOA with TVA. | | |
| **2012-5** | Introduce a virtual spread product. | | |

| SOM Number | Recommendations | High Benefit | Near Term |
|---|---|---|---|
| **2012-3** | Remove external congestion from interface prices. | | |
| **Operating Reserves and Guarantee Payments** | | | |
| 2018-3 | Procure reserves on the RDT and compensate the Joint Parties when the reserves are deployed. | | |
| 2016-4 | Establish regional reserve requirements and cost allocation. | ✓ | |
| 2014-2 | Introduce a 30-Minute reserve product to reflect VLR requirements and other local reliability needs. | ✓ | |
| **Dispatch Efficiency and Real-Time Market Operations** | | | |
| 2018-4 | Clarify the criteria and improve the logging for declaring emergencies and taking emergency actions. | | ✓ |
| 2017-5 | Assess the feasibility of implementing a 15-minute Day-Ahead Market under the Market System Enhancement. | ✓ | |
| 2017-4 | Improve operator logging tools and processes related to operator decisions and actions. | | |
| 2016-8 | Validate wind resources' forecasts and use results to correct dispatch instructions. | | ✓ |
| 2016-6 | Improve the accuracy of the LAC recommendations. | | ✓ |
| 2012-16 | Re-order MISO's emergency procedures to utilize demand response efficiently. | | ✓ |
| **Resource Adequacy** | | | |
| 2018-5 | Improve capacity accreditation to account for unforced and unreported outages and derates during tight supply periods. | ✓ | |
| 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. | | ✓ |
| 2017-7 | Establish PRA capacity credits for emergency resources that better reflect their expected availability and performance. | | ✓ |
| 2017-6 | Require the ICAP of planning resources to be deliverable. | | ✓ |
| 2016-9 | Improve the qualification of planning resources and treatment of unavailable resources. | | ✓ |
| 2015-6 | Improve the modeling of transmission constraints in the PRA. | | |
| 2015-5 | Implement firm capacity delivery procedures with PJM. | ✓✓ | |
| 2014-5 | Transition to seasonal capacity market procurements. | | |
| 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. 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 between locations.

*Ancillary Services Markets (ASM)* - that include operating reserves and regulation that are jointly optimized with the energy market to allocate resources efficiently and price shortages efficiently.

*Capacity Market* - implemented through the Planning Reserve Auction (PRA), which is not currently designed to facilitate efficient investment and retirement decisions, and for reasons described in this report requires reforms.

The energy and ancillary services markets provide a robust foundation for the challenges that lay ahead for decades to come. Nonetheless, the markets have continued to evolve to improve performance and meet the changing needs of the system. Key changes or improvements implemented in 2018 included:

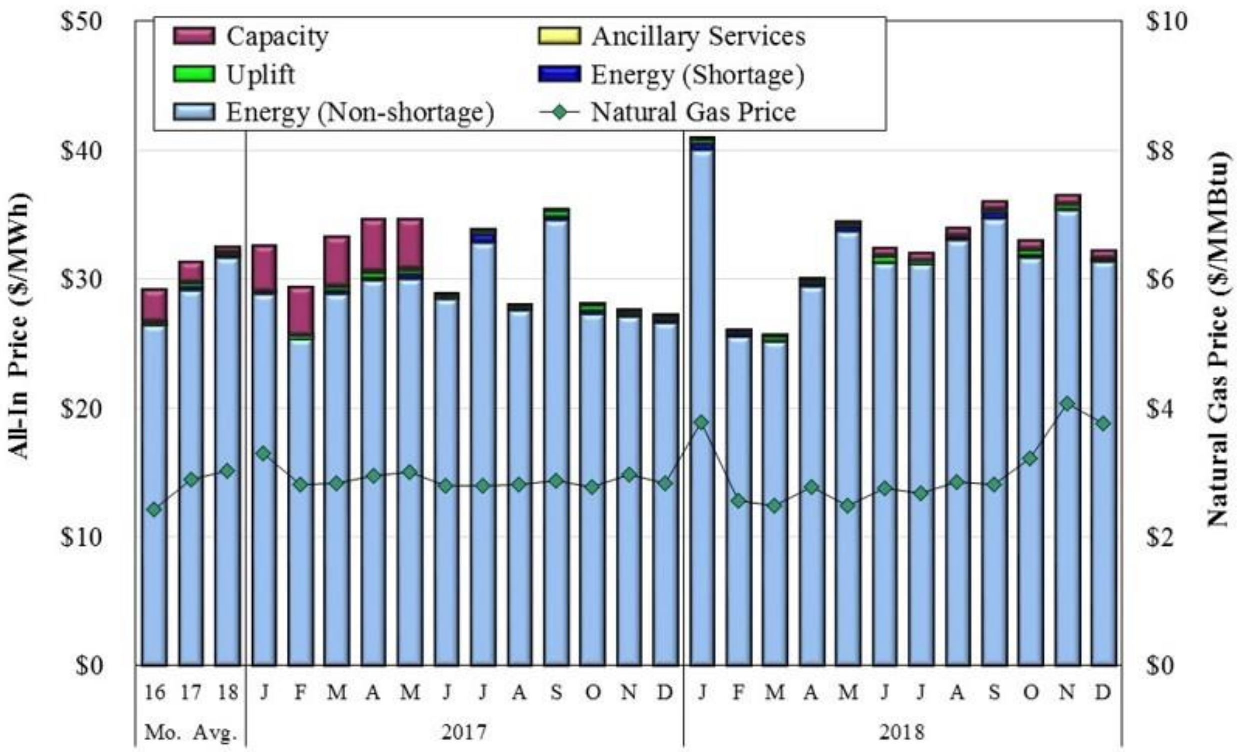
- On January 4, FERC granted MISO the authority to define Dynamic Narrow Constrained Areas (DNCAs) consistent with our SOM Recommendation 2012-9.
- On July 1, MISO implemented five-minute real-time settlements.
- On August 23, FERC granted MISO RSG mitigation authority for resources committed in MISO South for the RDT constraint and granted MISO the authority to apply the Reserve Procurement Enhancement (RPE) to the RDT.
- In October, MISO filed to reform Uninstructed Deviation and related make-whole payments, which FERC approved in January 2019 and were implemented in May 2019.
- In December 2018, MISO filed Tariff changes as part of the Resource Availability and Need (RAN) efforts to improve testing and access to LMRs, which FERC approved in February and March of 2019.

# II. PRICE AND LOAD TRENDS

## A. Market Prices in 2018

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 in MISO. 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 energy price that is associated with shortage pricing.

**Figure 1: All-In Price of Electricity**
2017–2018




The all-in price increased by four percent in 2018 to an average of $32.57 per MWh because:

- Energy prices increased by eight percent, primarily because of higher fuel prices and load. The contribution of shortage pricing remained relatively low. Weather-related events in January and rising fuel prices in the fall contributed to relatively higher energy prices in these months.

- The 2018-2019 capacity auction cleared at $10 per MW-day in all zones, except Zone 1 that cleared at $1 per MW-day. These prices are close to zero and led to a 73 percent decline in the capacity component of the all-in price. Capacity remains undervalued because of shortcomings in the PRA design, which we discuss below.

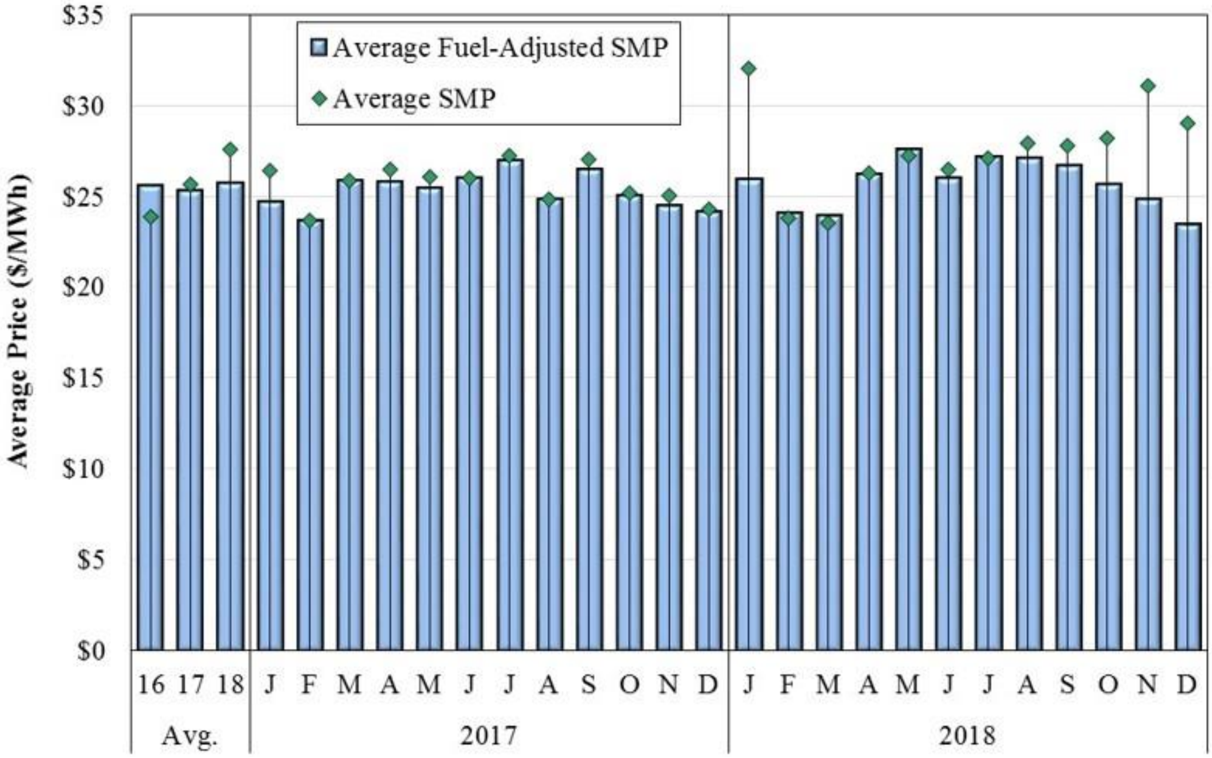
- The ancillary services component remained a very small portion of the all-in price and fell ten percent to $0.09 per MWh.

- The uplift component of the all-in price fell by $0.04 to $0.23 per MWh.[2]

The figure indicates that natural gas prices continued to be a primary driver of energy prices. This correlation is expected in a well-functioning, competitive market because fuel costs are the majority of most suppliers' marginal production costs. Suppliers have strong incentives in competitive markets to offer at their marginal cost, so fuel price changes result in comparable offer price changes. Energy prices rose faster than fuel prices in May because of unseasonably warm weather at the end of the month. Likewise, prices were relatively high in September because of multiple forced generation outages and tight operating conditions.

To estimate the effects of factors other than the change in fuel prices, we calculate a fuel price-adjusted System Marginal Price (SMP) that is 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.[3]

**Figure 2: Fuel-Adjusted System Marginal Price**
2017–2018




2 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.

3 See Figure A4 in the Appendix for a detailed explanation of this metric.

Although the nominal SMP in 2018 increased by seven percent over 2017, the fuel-price adjusted SMP rose just two percent. This increase was primarily because:

- Unusually mild summer temperatures in 2017 that contributed to load averaging five percent less than in 2018 and corresponding lower prices in 2017;
- Unusually high temperatures and load levels in May 2018; and
- Extremely cold temperatures in January of 2018 that led to much higher nominal prices and slightly higher fuel-adjusted prices.

## B. Fuel Prices and Energy Production

The resource mix and energy output were relatively unchanged from 2017 levels, although coal-fired capacity fell as over 2 GW retired. 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 2017 and 2018.

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

| | Unforced Capacity | | | | Energy Output | | Price Setting | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total (MW) | | Share (%) | | Share (%) | | SMP (%) | | LMP (%) | |
| | 2017 | 2018 | 2017 | 2018 | 2017 | 2018 | 2017 | 2018 | 2017 | 2018 |
| **Nuclear** | 12,420 | 12,225 | 10% | 10% | 16% | 16% | 0% | 0% | 0% | 0% |
| **Coal** | 50,843 | 48,775 | 39% | 38% | 47% | 46% | 55% | 46% | 84% | 78% |
| **Natural Gas** | 55,794 | 55,240 | 43% | 43% | 23% | 27% | 44% | 53% | 85% | 87% |
| **Oil** | 1,904 | 1,691 | 1% | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Hydro** | 3,929 | 3,966 | 3% | 3% | 1% | 1% | 0% | 1% | 1% | 1% |
| **Wind** | 2,610 | 3,005 | 2% | 2% | 8% | 8% | 0% | 0% | 30% | 31% |
| **Other** | 2,273 | 2,678 | 2% | 2% | 4% | 2% | 0% | 0% | 4% | 2% |
| **Total** | **129,773** | **127,580** | | | | | | | | |

*Energy Output Shares*. The lowest marginal cost resources (coal and nuclear) operated at the highest capacity factors and coal continued to produce the greatest share of energy. Natural gas units' share of output grew in 2018 to 27 percent but remained well below its share of capacity (43 percent) because a large portion of the gas-fired resources are peaking units that rarely run.

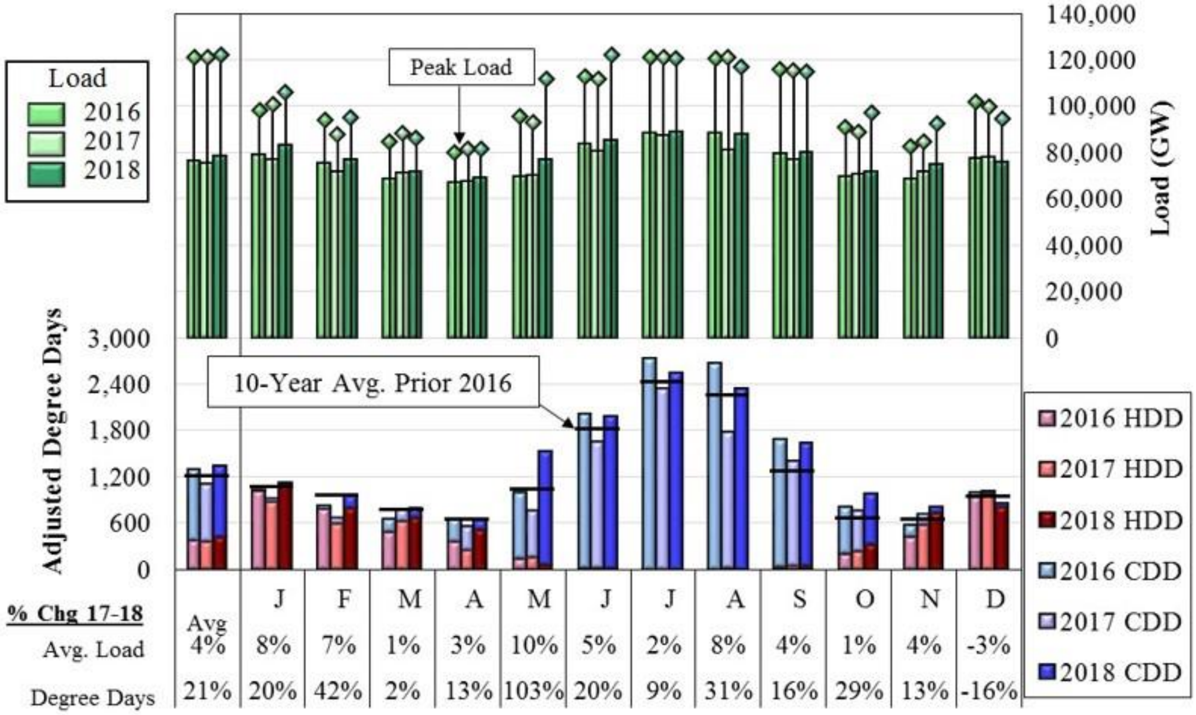
*Price-Setting Shares.* Coal resources set system-wide prices in 46 percent of hours, down from 55 percent in 2017. Although natural gas units produce a modest share of the energy in MISO, they play a pivotal role in setting energy prices. Gas-fired units set the system-wide price in more than half of all intervals for the year, including almost all peak hours when prices are highest. 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 they set local LMPs in 87 percent of intervals and why they are a key driver of energy prices.

*Wind Resources.* The capacity values in Table 1 are unforced capacity so they are derated from installed capacity levels to account for outages and intermittency. This has the largest effect on wind units, which are derated by 84 percent. Hence, they account for only two percent of the unforced capacity, but 8 percent of its energy output. Wind units also often cause congestion on lines exiting their locations, causing them to set prices in almost one third of all intervals.

## 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 determined by weather. Figure 3 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.[4]

**Figure 3: Heating- and Cooling-Degree Days**
2016–2018




The average degree days increased by 21 percent overall in 2018, as temperatures and weather patterns returned from the mild conditions of 2017 and actually exceeded historical seasonal trends. Increases in cooling degree days in May and October and heating degree days in January, February, and November contributed to higher average and peak loads in 2018.

4 HDDs and CDDs are defined using aggregate daily temperatures relative to a base temperature (65 degrees Fahrenheit). To normalize the relative impacts on load of HDDs and CDDs, HDDs are inflated by a factor of 6.07, based on a regression analysis. The historic average degree-days are based on data from 1971 to 2000.

MISO's annual peak load of 121.6 GW occurred on June 29, almost a month earlier than the peak load in prior years. Actual peak load was well below the forecasted peak of 124.7 GW from MISO's *2018 Summer Resource Assessment.*

In 2018, MISO experienced several weather-related events that impacted prices and load:

- In early January, very cold temperatures throughout the footprint affected gas prices, generation outages, and energy prices. Significant temperature-related fuel price volatility in late December 2017 and early January contributed to high congestion and price volatility during this period.
- Unusually cold weather in the South on January 17 and 18 led to a MISO South record winter peak of 32.1 GW. Temperature-related forced generation outages contributed to tight operating conditions and the declaration of a regional emergency.
- Record high temperatures in late May led to challenging operating conditions, high prices, and high congestion in the period from May 27 through May 30. High river temperatures caused deratings and a unit outage in the Central Region.
- A heat dome affected a significant portion of the footprint in late June and early July, sharply increasing average and peak loads in June relative to 2017.
- In early September, Tropical Storm Gordon led to Severe Weather Alerts and Conservative Operations in the South.

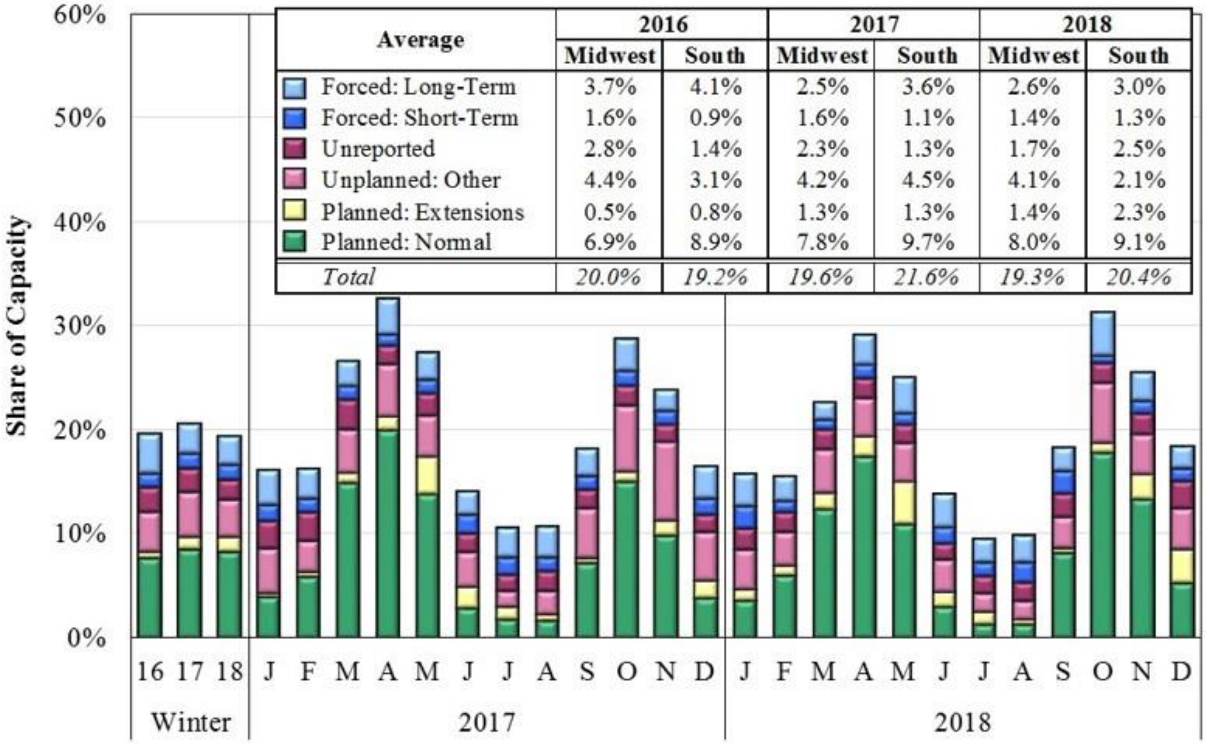
Emergency events have become more frequent because MISO's capacity surplus has fallen as a number of retirements of older baseload units have been partially offset by the entry of renewable resources. Emergency events are generally the result of a combination of factors, including severe weather, load forecasting errors, and significant generator or transmission outages. These events are important to evaluate because they reveal how well the market performs under stress. Therefore, Section III evaluates these events.

## D. Outage Scheduling

Proper coordination of planned outages is essential to ensure that enough capacity is available to meet the load if contingencies or higher than expected load occurs. MISO approves all planned outages that do not raise reliability concerns, but otherwise does not coordinate the outages. To evaluate the outages that occurred in 2018, Figure 4 shows MISO's available capacity, outages, peak load, and emergency conditions in MISO Midwest and South.

In 2018, outage rates fell relative to 2017. Short-notice planned outages were especially high in May and contributed to high prices. A large share of these outages were extensions of planned outages. As in 2017, true planned outages were very low for most of the summer, and total outages in the fall were slightly higher than last year.

**Figure 4: MISO Outages**
2017–2018




In our 2016 SOM Report, we recommended MISO enhance its transmission and generation planned outage approval authority (see 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.

We have also recommended that MISO improve its capacity accreditation rules to improve suppliers' incentives to schedule outages efficiently and be available when needed. In 2017, MISO introduced the Resource Availability and Need (RAN) project to address these issues. In January 2019, MISO filed Phase 1 proposed Tariff changes[5] that modify capacity accreditation rules to deter generators from scheduling short-notice outages during tight conditions and to increase MISO's ability to call LMRs. FERC approved the changes in March 2019. These changes represent a modest positive step but will have limited effects.

Hence, we recommend additional changes in future Phases of the RAN initiative that will provide more efficient incentives for suppliers to avoid scheduling outages and to be available when resources are needed most (see 2018-5).

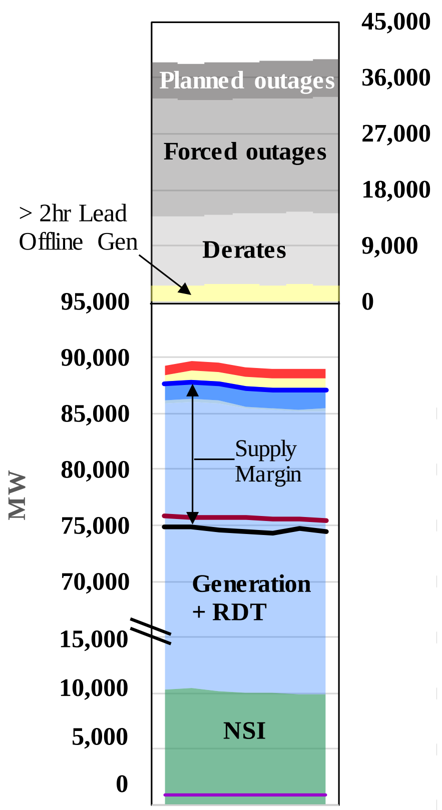
5 Docket No. ER19-915-000: *Midcontinent Independent System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii: 2019-01-30_RAN Outage Coordination Filing to be effective 4/1/2019*.

## III. Detailed Review of Emergency Events

Over the past few years, MISO has experienced a significant increase in the frequency and severity of generation emergencies. Much of this increase is attributable to a narrowing reserve margin and impacts of the market's evolving generation mix. Investments in gas-fired resources, renewable resources, and load-modifying resources have replaced much of the energy lost because of retirements of coal and nuclear baseload resources. Increased intermittent output and its associated fluctuations, along with increased reliance on LMRs that can only be deployed during emergencies has resulted in more frequent emergency events.

MISO declared three emergencies in regions or local areas throughout the footprint in 2018, and two emergencies on consecutive days in early 2019. On four of these occasions, MISO scheduled LMRs, but the LMRs available to the market were greatly limited by long notification times. On two of these occasions, MISO employed more extensive emergency procedures, including buying emergency power from its neighbors.

In this Section, we review and discuss the emergency events, including the causes, MISO's operating actions, and the resulting prices. Although each emergency had unique characteristics, the events reveal some common issues and opportunities for improvements. We utilize figures that show each of the components of the available and unavailable supply and the demand to be served. The illustration two the left shows each element of these figures.




The figures include the total available supply (royal blue line), consisting of NSI (green area), online generation, the RDT capability into the area, and offline resources that can start in less than 30 minutes (blue area), online emergency generator ranges utilized (dark blue area), and emergency transactions (if any, they are shown in orange).

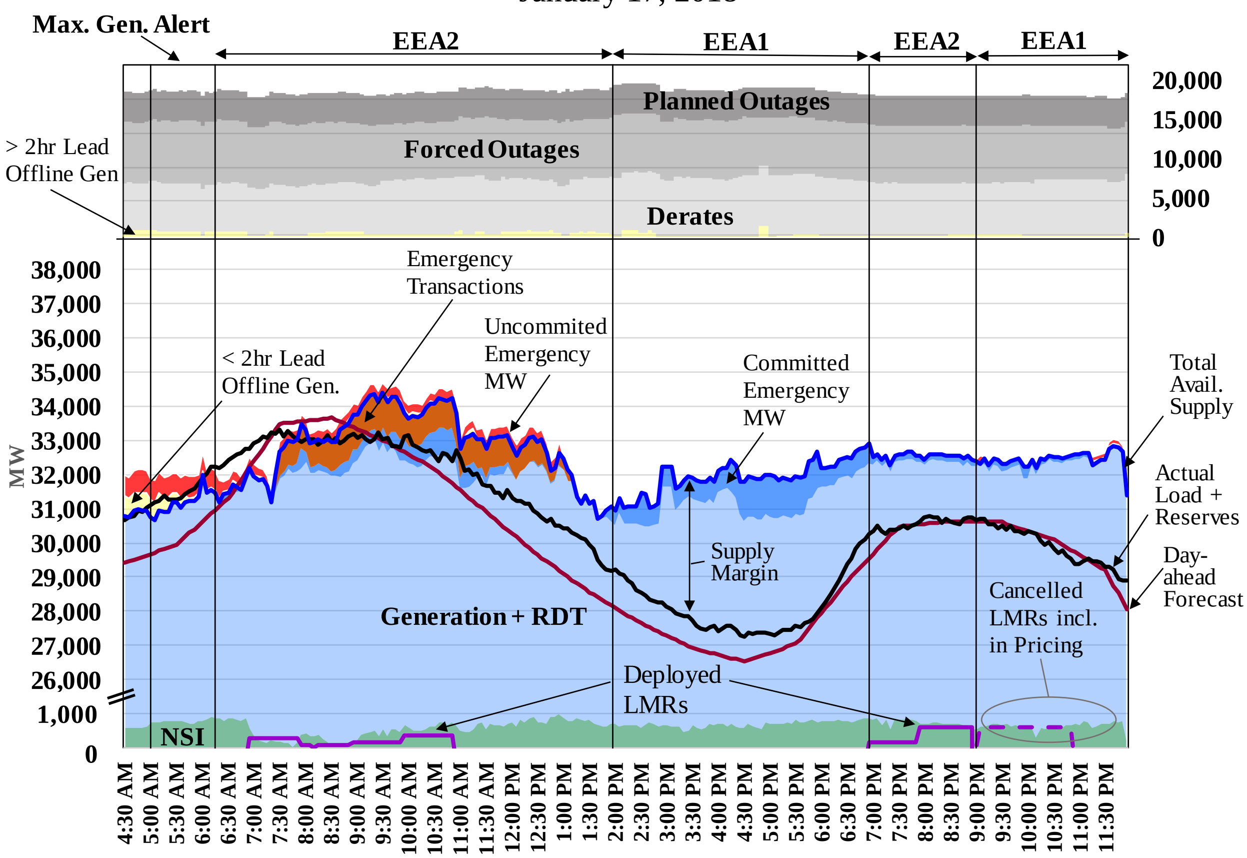
The total available supply can be compared to the total demand. Total Demand is equal to the actual real-time load plus a regional reserve requirement (based on the largest generator contingency). The figure includes this actual demand and the day-ahead forecast of the demand. The supply margin can be determined at any point in time by comparing the total demand (the black line) and the total available supply (the blue line). The supply margin is the difference – MISO experiences a capacity deficiency when the black line exceeds the blue line, which will result in MISO exceeding the RDT scheduling limit when the largest contingency occurs in the North or South.

The bottom panel in the figure also shows supply that is *not* available to the real-time market, which are shown above the royal blue total supply line. This supply includes offline generators with modest start times (< 2 hours and > 30 minutes) shown by the yellow area and offline emergency generation (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), as well as planned outages, forced outages, and derates.

## A. January 17-18, 2018: Emergency Event and LMR Deployments in MISO South

On January 17 and 18, 2018, unusually cold weather in the South region caused a record winter peak load in the South of 32.1 GW and high levels of forced outages, which resulted in an emergency event.[6] The conditions in MISO South on January 17 are shown in Figure 5 below.

**Figure 5: Maximum Generation Emergency in MISO South**
January 17, 2018




On January 17, conditions were extremely tight from 4 a.m. to 1 p.m. MISO experienced forced outages of 2.5 GW between midnight and 8:30 a.m. in the South region caused by the fact that most generators in the South are not designed to withstand the unusually cold temperatures. MISO's short-term load forecast in the early morning (3:20 a.m.) indicated a capacity deficiency

6 The all-time MISO South peak was set at 32.7 GW in August 2015.

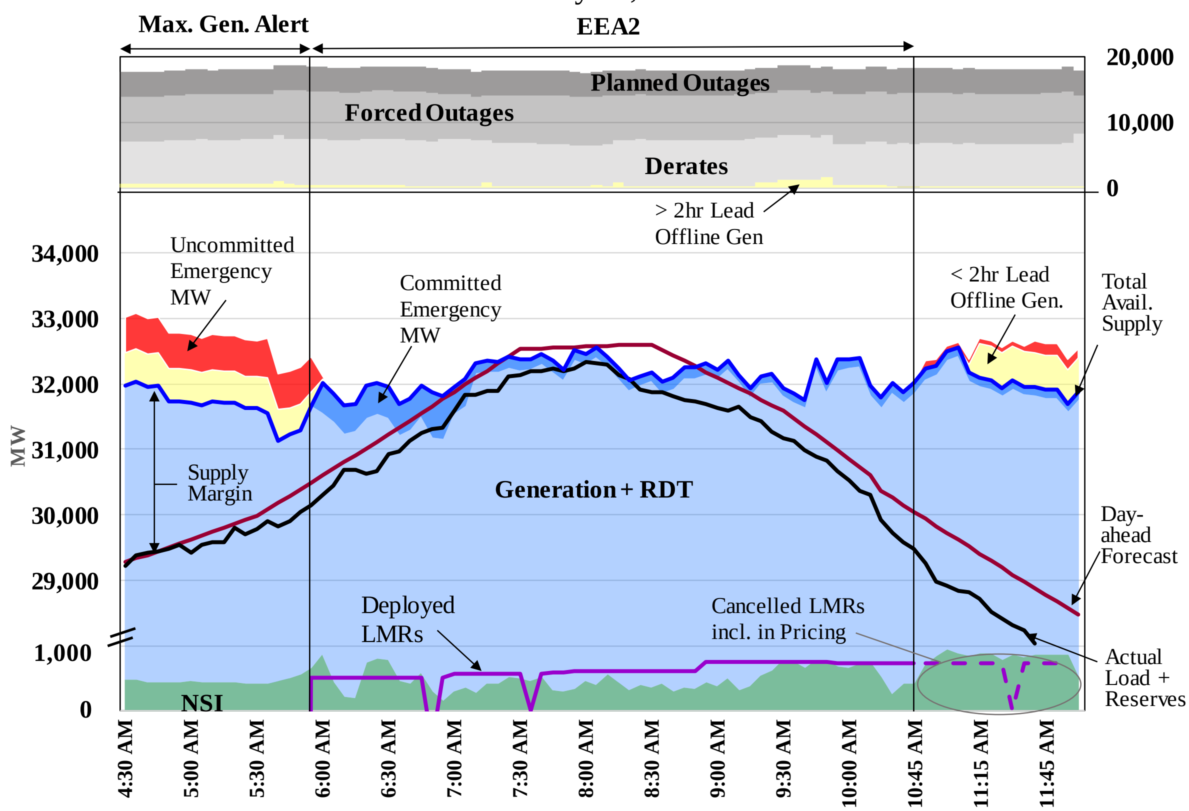
by 5:15 a.m. and it actually became capacity deficient at roughly 5 a.m. MISO upgraded its previously declared Maximum Generation Alert to a Maximum Generation Event (level EEA2) at 6:10 a.m.

Because the demand substantially exceeded the supply early in the January 17 event, MISO's modeled flow exceeded the RDT limit by as much as 1,000 MW for roughly an hour from 6:45 a.m. to 7:45 a.m. Our figure shows that MISO was capacity deficient in the South as early as 4:45 a.m., indicating that it would not have been able to recover from the loss of the largest contingency within 30 minutes and restore the RDT flows to below its limit. MISO ultimately resolved this deficiency and reduced the RDT flows by scheduling emergency transactions from neighboring balancing areas beginning at 7:30 a.m., which increased to more than 1,000 MW by 9 a.m. MISO also relaxed some of its transmission limits in the South by raising them by roughly 25 percent, allowing it to increase the output of some stranded resources.

MISO's EEA2 declaration allowed it to access LMRs in MISO South, but they provided very little relief because most of the LMRs had notification times that are too long to respond during the capacity shortage. MISO declared a second EEA2 for the afternoon peak period, and because of the advance notice more LMRs were able to be scheduled. However, the LMRs were not needed and the event was cancelled early at 9 p.m. The cold temperatures and high loads continued on January 18 and Figure 6 shows capacity and load conditions on this day.

**Figure 6: Maximum Generation Emergency in MISO South**

January 18, 2018



MISO declared an emergency for the morning of January 18 well in advance to ensure access to LMRs. Conditions were less tight on January 18 because some units returned to service from outage. Figure 6 shows that MISO utilized emergency ranges on online generators, committed offline short-lead resources, and deployed more than 600 MW of LMRs to ensure reliability on the morning of January 18. These actions were advisable as the total supply narrowly exceeded demand for energy and reserves during the morning peak.

Based on our evaluation of the January 17-18, 2018 events, we conclude that MISO's operating actions were necessary to avoid firm load curtailments in the South. The emergency actions were timely on January 18 and allowed MISO to avoid a capacity deficiency. The emergency declarations and actions on January 17 were not as timely, which resulted in a sizable capacity deficiency, an exceedance of the RDT, and limited ability to utilize the LMRs and other emergency resources. This event underscores the value improving the procedures for declaring emergencies and utilizing LMRs and other emergency resources.

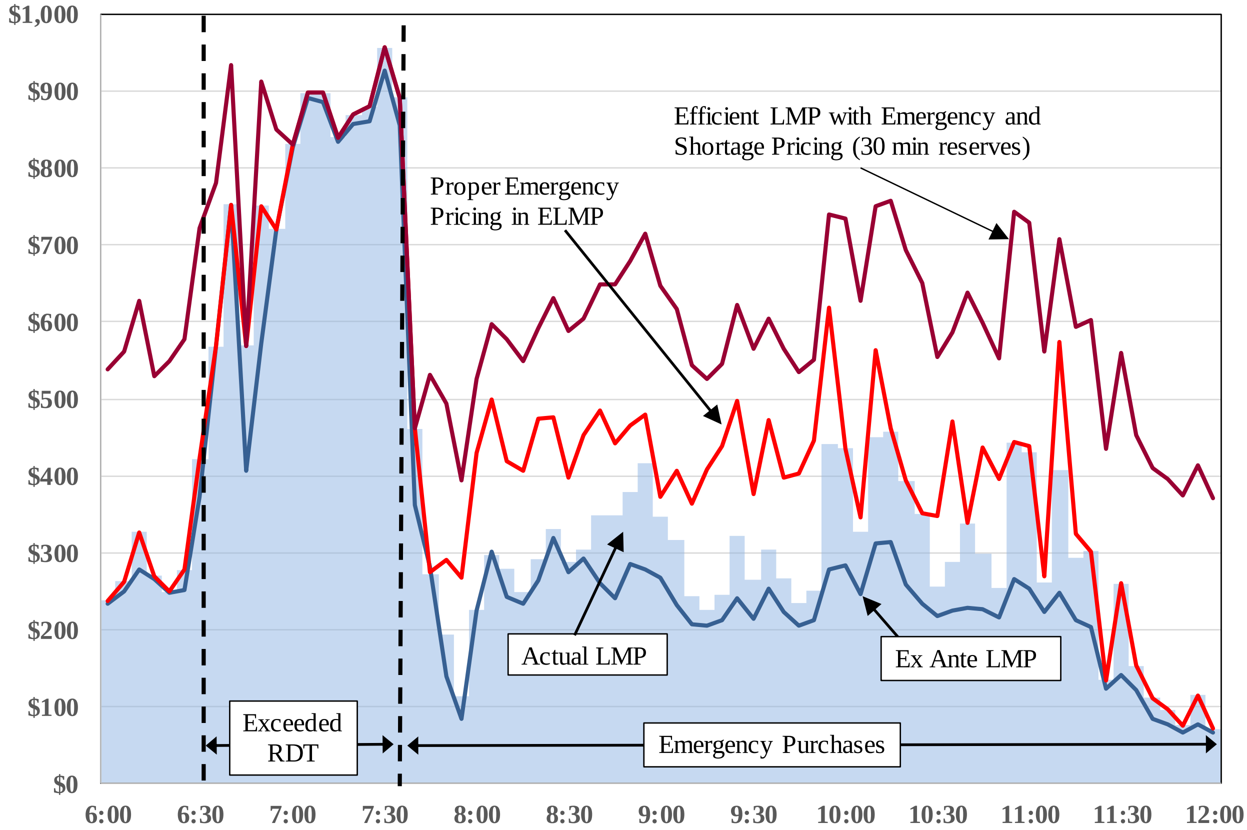
Figure 7 shows our evaluation of prices during the January 17, 2018 event. The blue line indicates the ex-ante LMP produced by the real-time market dispatch, and the blue shading in the background shows the ex-post LMPs produced by the ELMP software that includes the pricing of MISO's fast-starting resources and emergency actions. Our evaluation of MISO's ex-post prices during this event indicates that MISO's emergency pricing did not perform well because of a flaw in the emergency pricing software, which does not properly account for the impact of the emergency power purchases on the RDT flows.

The red line indicates the price that the ELMP model should have produced. Even these prices, however, do not reflect the costs of being short of reserves in the South (because MISO does not currently have a regional reserve product). The top maroon line shows our estimate of efficient regional pricing that includes pricing the shortages of the regional reserves MISO attempts to hold. For this figure, we assume a demand curve for these regional reserves of $500 per MW, which we believe reflects their approximate value to the system.

The evaluation of the energy prices during the January 17 event shows that prices were high when the RDT was violated because the RDT demand curve set the price in the South. Once the emergency purchases began and the RDT violation was resolved, the prices fell and the emergency pricing did not efficiently reflect the ongoing emergency because:

- The emergency pricing in the ELMP model did not properly account for RDT flow impacts of the emergency transactions. The ELMP model should have recognized that without the emergency transactions, the flows on RDT would have been much higher and set a higher price in the South.
- Allowing a resource's offers to determine the floor can result in an inefficiently high or low floor. In this case, the emergency price floor was set at an inefficiently low level by a unit's offer. We recommend MISO establish reasonable floors (see 2018-1).

**Figure 7: Evaluation of Real-Time Emergency Prices**
January 17, 2018

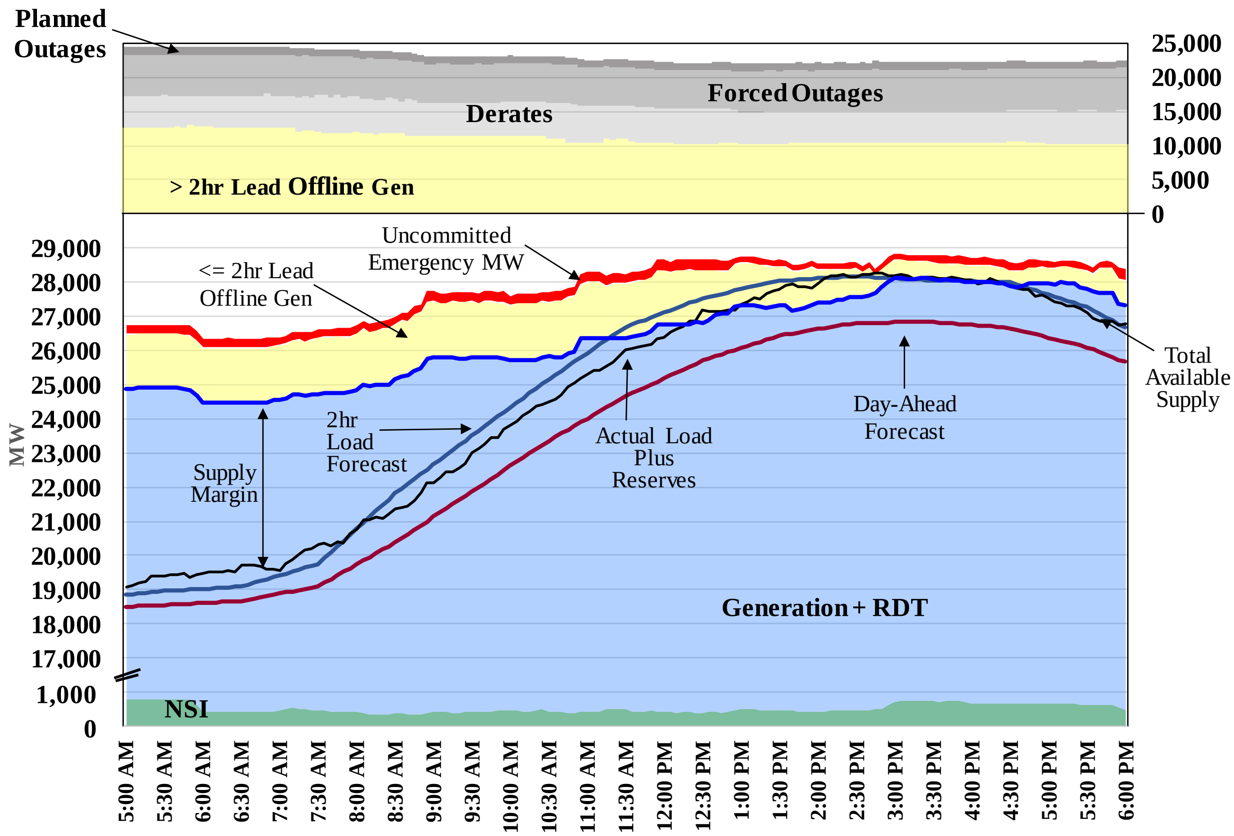



In addition to these issues with the emergency pricing provisions, MISO was short of the reserves it typically attempts to hold in the South. We have recommended MISO implement a local 30-minute reserve product to satisfy this requirement the market (see 2014-2 and 2016-4). MISO is working to implement this reserve product and it will allow the market to recognize and price future reserve shortages (estimated by the maroon line in the figure).

## B. September 2018 Events

On back-to-back Saturdays in September 2018, MISO experienced similar forecast-driven events in the South region. MISO did not declare an emergency on September 8 but did on September 15. On both days, the participants under-procured demand through the day-ahead market likely because the actual load was higher than they had forecasted. Likewise, MISO under-forecasted the load in the day-ahead timeframe causing it to increase resource commitments after the day-ahead market. MISO was ultimately short of the reserves it attempts to hold in the South to be able to respond to the largest contingency. On September 8 the largest contingency was a 1,400 MW unit, and on September 15 the largest contingency was a 1,200 MW unit. Figure 8 shows the conditions on September 8.

**Figure 8: Capacity Shortage Conditions in MISO South**
September 8, 2018



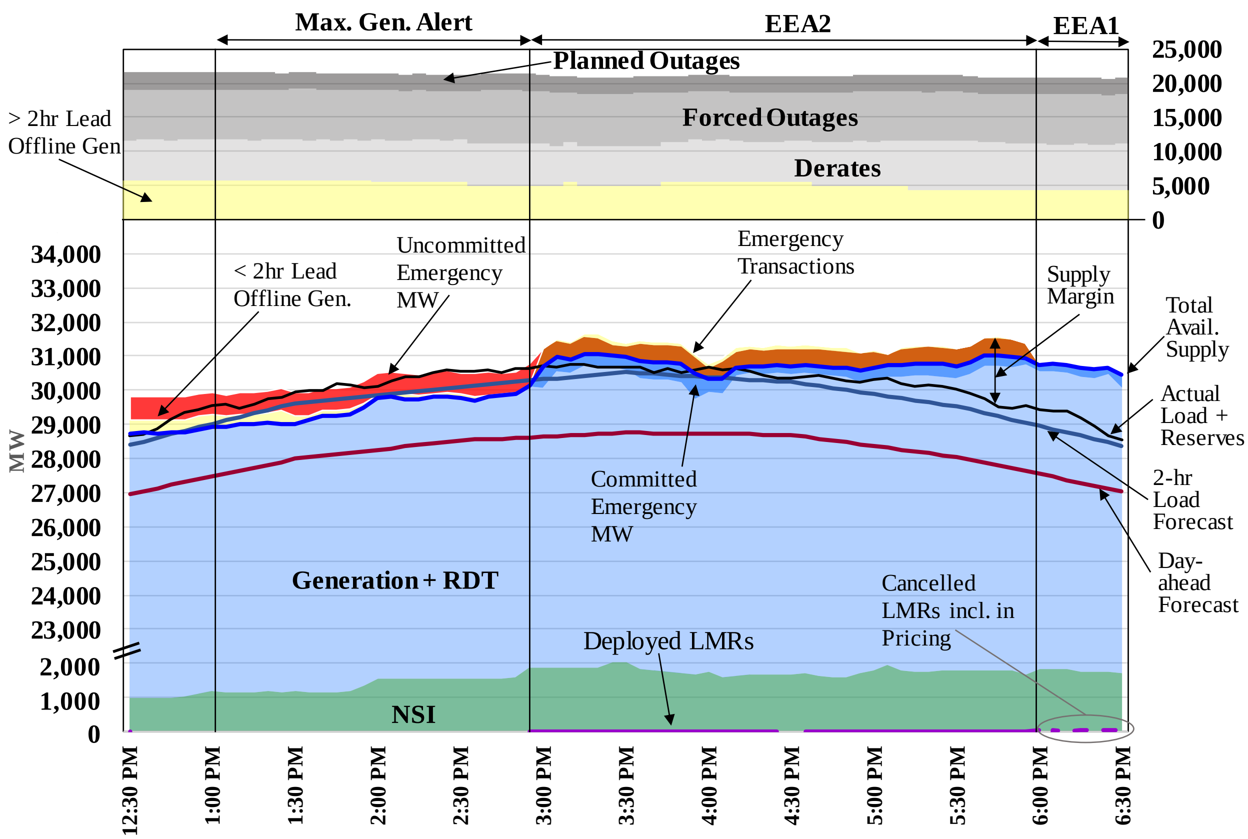

On the evening of September 7, approximately 3,300 MW of resources were decommitted in anticipation of lower forecasted load on Saturday, September 8. However, load in the South did not fall as much as anticipated and by 8 a.m. on the morning of September 8, the two-hour forecast in MISO South began to diverge from the day-ahead forecast. By 11:30 a.m. the two-hour forecast was indicating that MISO would not be able to withstand the largest contingency in MISO South without violating the RDT (the forecasted demand exceeding the supply). The actual load plus reserve needs exceeded the total available supply by 12:20 p.m. At this time the RPE limit on the RDT was in violation, indicating that MISO could not recover to the contractual RDT limit within 30 minutes post-contingency.[7] The violation on the RPE constraint exceeded 500 MW by 2 p.m. MISO did respond by committing a number of its resources that had start-up times less than two hours, but these commitments did not occur early enough to avoid the capacity deficiency. Given these conditions, an emergency declaration was

7 In late August, MISO began to model the Reserve Procurement Enhancement (RPE) on the RDT, which allows MISO to clear reserves by holding generation below its optimal dispatch in the South or committing additional units in order to prevent MISO from exceeding the contractual flow limits on the RDT in the event of the loss of the largest contingency.

warranted, which would have allowed MISO to access emergency ranges on online units and start emergency-only units and LMRs to avoid the deficiency.

A week later on September 15, very similar conditions occurred. On the evening of September 14, MISO lost the largest single contingency in MISO South, a 1,400 MW nuclear unit. As on September 8, the procurements through the day-ahead market and MISO's day-ahead load forecast for September 15 were both significantly below the actual real-time load because of temperature forecast errors. Figure 9 below illustrates conditions on that day.

**Figure 9: Capacity Shortage Conditions in MISO South**
September 15, 2018

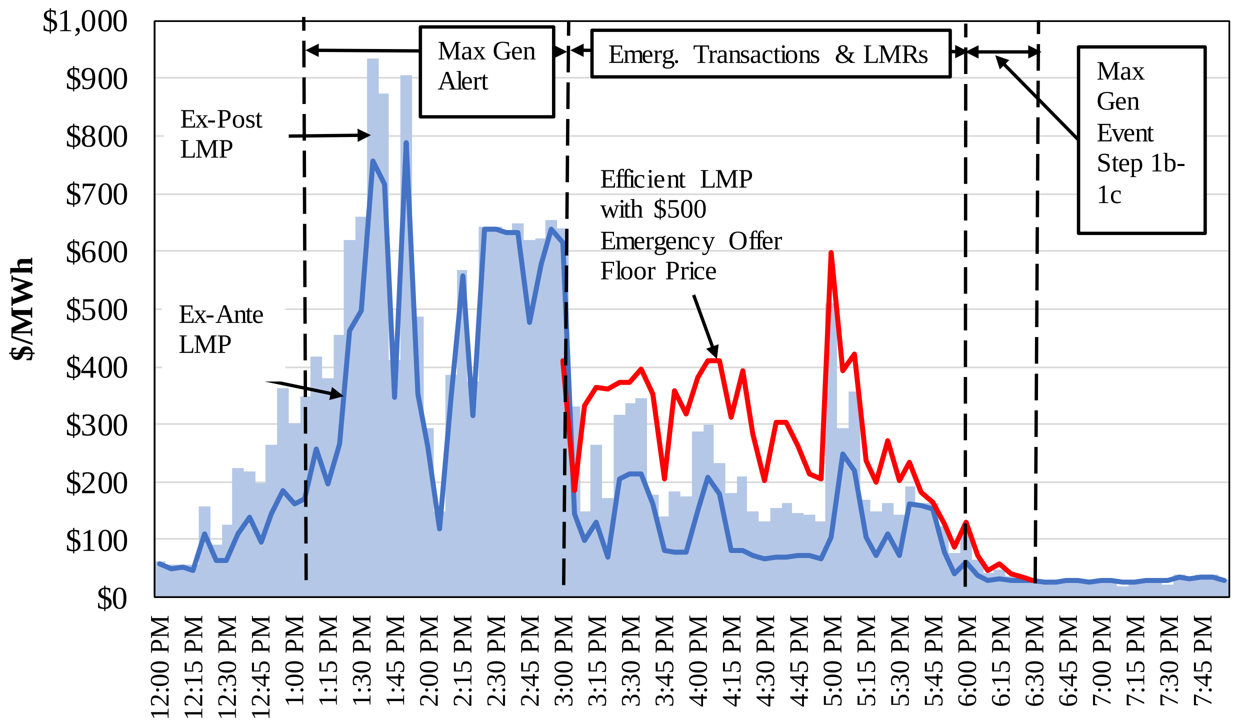



At 11:30 a.m., the Look-Ahead Commitment (LAC) cases began to indicate emergency conditions beginning at 1:30 p.m. and MISO had less than 150 MW of headroom (total reserves) in the South by that time. MISO's largest contingency in the South was approximately 1,200 MW, so its ability to respond if this contingency had occurred was extremely limited. By 12:45 p.m. the RPE constraint on RDT was binding and in violation, and this contributed to high LMPs in the South.

MISO declared a Maximum Generation Emergency Event at 2:45 p.m. to begin at 3:00 p.m., which allowed it to access emergency generation and imports (1,200 MW in total), and schedule LMRs. These actions, together with the response of non-emergency imports, effectively resolved the capacity deficiency although the shortage had persisted for more than two hours prior to those actions. Almost no LMRs were able to be utilized (only 6 MW) because of their notification times and the timing of the emergency declaration.

Tight capacity conditions and local transmission congestion beginning at 12:45 p.m. made it difficult for MISO to hold the flow on the RDT. Violating the RDT caused the Transmission Constraint Demand Curve (TCDC) for the RDT to set very high prices throughout the region. These price signals prompted participants to increase net imports into the South by roughly 1 GW from 1 p.m. to 3 p.m. Figure 10 shows the pricing on September 15.

**Figure 10: Emergency Pricing in MISO South**
September 15, 2018




**5:00 p.m. interval averaged $1,430.76 ex-ante but was later re-priced due to excessive*

At 3 p.m. the emergency began, and prices dropped precipitously. The Emergency Offer Floor Price of $119 per MWh applied to the emergency MWs was set inefficiently low. This prevented the emergency pricing in ELMP to set prices at efficient levels that reflected the emergency conditions.

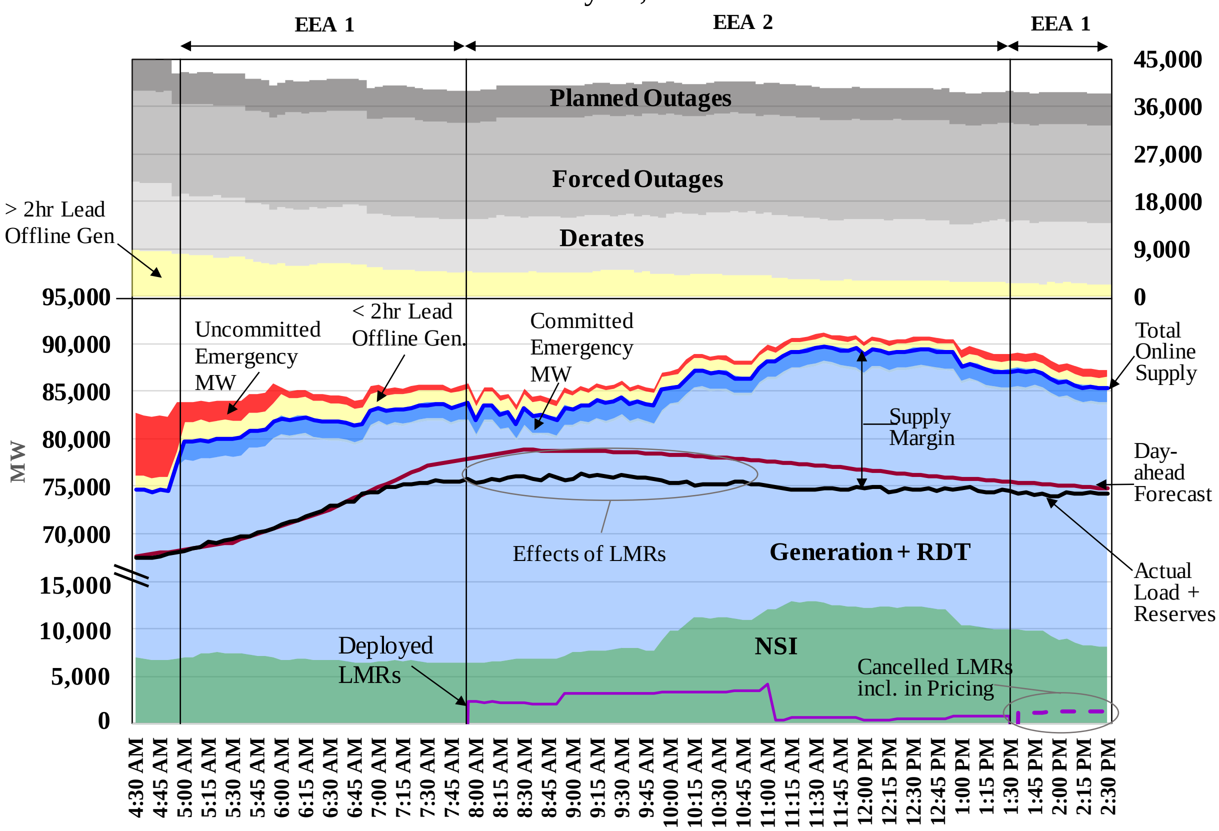
Figure 10 also shows that if a fixed emergency offer floor price of $500 per MWh had been used instead of the $119 floor price, real-time prices would have been 36 percent higher during the event. In this scenario, the emergency MWs would have been dispatched down in the ELMP model and would not have set the real-time prices. Pricing the emergency MWs at $119 caused them not to ramp down in the ELMP model and frequently set prices during the event.

## C. January 30-31, 2019: Emergency Conditions in the Midwest

In late January 2019, MISO declared Cold Weather Alerts for January 29 through February 1 because temperatures were extremely cold throughout the Midwest region. On January 30, MISO issued a Maximum Generation Event in the North and Central Regions because the unusually cold weather resulted in: a) a sharp decline in wind output relative to the day-ahead forecast, b) issues with transmission elements (circuit breakers) impacted by arctic conditions, and c) uncertainty regarding forced outages that may result from the cold temperatures. Figure 11 below illustrates conditions in the Midwest on January 30, 2019.

**Figure 11: Emergency Conditions in MISO Midwest**

January 30, 2019



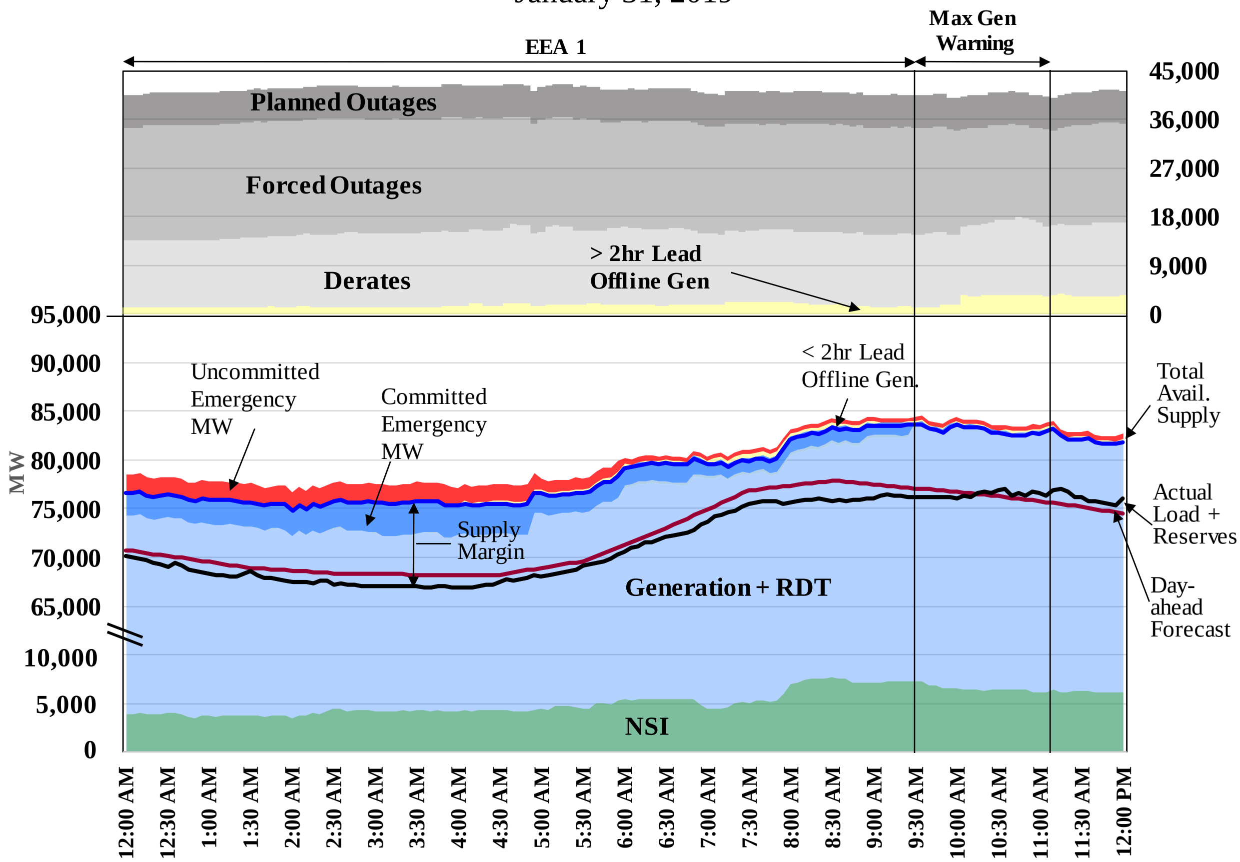

In the early morning hours of January 30, MISO declared an Energy Emergency Alert (EEA) Level 1 beginning at 5:00 a.m., allowing MISO to access emergency generation. By 6:19 a.m. the forecasted load indicated that MISO would be facing a tight supply margin during the morning ramp hours, so MISO elevated the Emergency to an EEA 2 beginning at 8:00 a.m. This provided MISO access to approximately 2.5 GW of LMRs in the North and Central Region. An additional 1,500 MW of LMRs voluntarily curtailed, with the net result that the actual load was significantly under the forecasted value.

At 1:30 p.m. MISO downgraded the event to EEA 1 and cancelled the LMRs. This EEA1 emergency declaration was later extended through noon the following day in order to maintain access to emergency ranges and emergency-only units. Net imports increased roughly 8 GW from the day-ahead amount by noon on January 30, largely because of high prices produced by MISO's emergency pricing discussed below. MISO cancelled the LMRs at 11 a.m., and re-deployed approximately 1 GW of LMRs in just the North zone beginning at 11 a.m. As shown in the figure, by 11:30 a.m. MISO had nearly 15 GW of supply margin, which fell to roughly 5 GW at 9:15 p.m. as load grew through the evening. After 3 p.m., MISO started or extended 198 units totaling 13.3 GW through noon the following day, resulting in $8 million in RSG. MISO had a substantial capacity surplus on that day, and in retrospect did not need the curtailments. However, MISO's actions during the highly unusual conditions were understandable given the high degree of uncertainty caused by extreme temperatures.

On the morning of January 31, the supply margin averaged more than 6.5 GW. Conditions on that day are shown in Figure 12 below. MISO kept a significant number of units online from the prior day because of concerns that units would not be able to restart once they had turned off. Additionally, MISO extended the EEA 1 declaration from the prior day to maintain access to the online emergency ranges of generators. In retrospect, MISO did not need the emergency MWs, and reliability could have been ensured through the commitment extensions of online resources.

**Figure 12: Emergency Conditions in MISO Midwest**

January 31, 2019



Although MISO never approached a capacity deficiency during this event, the emergency pricing produced relatively high prices as shown in Figure 13. On January 30, the default emergency offer floor was set above $600 per MWh. The emergency MWs frequently set ELMP prices between 8 a.m. and 11 a.m. for the reasons discussed below.

When emergency resources are deployed, generators must ramp down to accommodate the influx of emergency power and maintain the t energy balance. For pricing purposes, MISO's ELMP models emergency output as dispatchable with an offer price equal to the emergency offer floor prices (Tier I or II). The ELMP model attempts to determine whether the emergency output is economic by ramping up lower-cost non-emergency resources. Because the total emergency output (including LMRs) was so large on that day, the ELMP model generally lacked the ramp capability to displace the emergency resources within a five-minute market interval. Hence, the default emergency offer set prices consistently above $600 per MWh from 8 a.m. to 11 a.m. on January 30 even though the system would not have been deficient without the LMRs.

**Figure 13: Emergency Pricing in MISO Midwest**
January 30, 2019

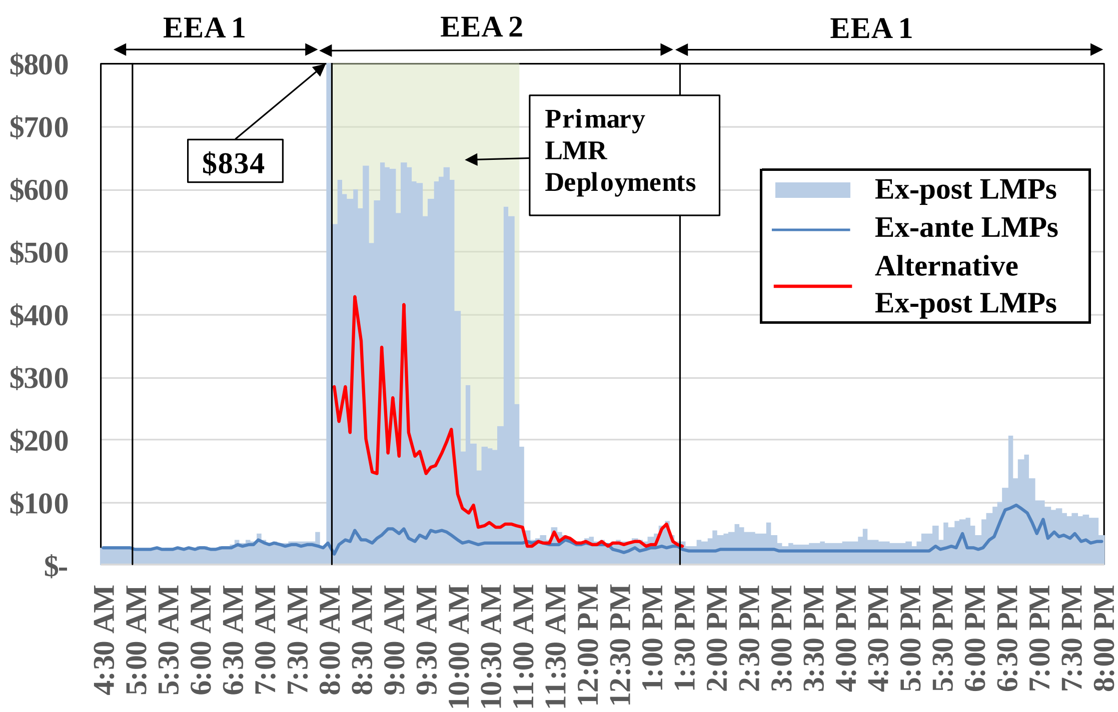



Figure 13 shows the prices that would have resulted if non-emergency resources were allowed more than five minutes of ramp capability to replace the emergency MWs (shown by the red line). Our analysis shows that prices during the event would have been 61 percent lower in the Midwest Region and 68 percent lower in the South Region across the EEA 2 event. Higher emergency pricing significantly lowered RSG and raised PVMWPs, resulting in a net make-whole payment increase of $3 million. We have recommended that MISO evaluate the ramp assumptions in ELMP, which could improve pricing in these types of events.

## D. Evaluation of Emergency Offer Floors

During emergency events, MISO can access supply outside of the market that is unavailable during non-emergency conditions, some of which is not dispatchable. To prevent the emergency supply from depressing prices, MISO's emergency pricing construct applies Emergency Offer Floor Prices to these emergency MWs in the ELMP pricing engine to allow them to set prices. An efficient Emergency Offer Floor Price should satisfy the following criteria:

- The value should reflect the cost of reliability requirements or constraints that would not be satisfied without the emergency MWs;
- The value should be stable and knowable in advance; and
- The value should not be subject to manipulation by any single entity.

The offer floors are set based on the highest resource offers (economic or emergency, depending on the emergency tier) in the affected area. Because these offer floors are set by suppliers' offers, the floors can vary widely. In 2018, MISO declared five emergencies in local areas throughout the footprint. MISO also declared local emergencies in the Central and North Regions on two days in January 2019. In most of these cases, we believe the emergency offer floors applied in these events substantially understated the true value of emergency power. However, the risk remains that a single entity could raise a single resource's offer and sharply inflate the Emergency Offer Floor Price.

We conducted an analysis to determine the extent of the volatility of calculated emergency offer floor prices in 2017 and 2018 based on resources' offers in all hours. This analysis shows the emergency offer floor prices that would have prevailed were MISO to have declared an emergency in the South or Midwest regions. In Table 2, we show the minimum and maximum values that were calculated by region, as well as the largest inter-hour change.

**Table 2: Extreme Values of Emergency Offer Floor Prices**

2017–2018

| Region | Extreme Values | | Largest |
|---|---|---|---|
| | Minimum | Maximum | Inter-hour Change |
| **MIDWEST** | $335 | $1,081 | $593 |
| **SOUTH** | $109 | $525 | $198 |

Our results indicate that the current emergency floor price calculations result in a high degree of variability because it depends on suppliers' offers. For instance, for at least one interval the emergency offer floor price in MISO South would have been as low as $109 per MWh, which is close to the emergency offer floor actually used during some of the emergencies in MISO South.

This vastly understates the reliability risks of the emergency and, therefore, do not satisfy the principles above. As a consequence, the energy prices would not induce imports from other regions or provided adequate compensation for resources needed to resolve the emergency.

Alternatively, the emergency offer floor price in the Midwest would have exceeded $1,000 per MWh during emergency conditions on some occasions, and it could be more than $2,000 if a supplier submits a higher-priced offer. This is inefficiently high for regional emergencies where violating the RDT is the primary reliability risk. The value of the RDT is indicated by its transmission constraint demand curve level of $500 per MWh. To address the concerns with the emergency pricing, we recommend MISO establish new rules for determining the emergency offer floors to ensure that they are set at levels that reflect the reliability risks of the emergency.

## E. Conclusions and Recommendations: Emergency Procedures and Pricing

Our review of the events in 2018 and early 2019 highlight a number of issues regarding the market rules and processes that are described below, along with associated recommendations.

- *Regional Emergency Procedures and Declarations:* Emergency events have become more frequent beginning in 2017. The timing of MISO's emergency declarations has been inconsistent relative to the regional capacity margins (the difference between the regional supply and demand). In some cases, emergency events were not declared after a capacity deficiency had been forecasted or actually occurred, whereas in other cases the emergency declaration was not needed in retrospect. Hence, we recommend that MISO evaluate and clarify its operating procedures, tools, and criteria for declaring emergencies, and improve its logging of these determinations.
- *LMRs:* LMRs generally provided minimal value because of their long lead times and lack of requirement to participate outside the summer months. MISO has improved its ability to access LMRs, but we continue to recommend that MISO consider changes in how MISO accredit LMRs and other emergency resources under Module E.
- *Emergency Floor Prices:* The emergency pricing rules that set the offer price floors based on a single supplier's offer can result in prices that are much higher or much lower than efficient levels. We recommend that MISO establish rules in the Tariff governing the calculation of the emergency offer floors that will ensure they are set at efficient levels.
- *Ramp Constraints in ELMP*: We continue to recommend that MISO evaluate options for improving the ramp constraints in ELMP to ensure that it appropriately determines when emergency MWs and fast-start units are needed and should set prices.
- *Engagement of 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.

# IV. Day-Ahead Market Performance

MISO's spot markets for electricity operate in two timeframes: in real time and one day ahead. The real-time market reflects actual physical supply and demand conditions. The day-ahead market operates in advance of the real-time market. The day-ahead market is largely financial, establishing financially-binding, one-day forward contracts for energy and ancillary services.[8] Resources that clear in the day-ahead market receive financially-binding schedules and settle any deviations at real-time prices.[9] The day-ahead market performed competitively in 2018.

The performance of the day-ahead market is important for the following reasons:

- Most generators in MISO are committed through the day-ahead market, and therefore good market performance is essential to efficient commitment of MISO's generation;[10]
- 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. Price Convergence with the Real-Time Market

Day-ahead market performance is primarily evaluated by the degree to which it converges with the real-time market because the real-time market reflects actual physical supply and demand for electricity. Participants' day-ahead market bids and offers should reflect their expectations of market conditions for the following day. However, a number of factors can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead market, such as wind or load forecast error, real-time output volatility, and forced generation or transmission outages. While these factors may limit convergence in a well-performing market on an hourly basis, prices should converge over longer timeframes (monthly or annually).

Figure 14 shows monthly and annual price convergence statistics. The upper panel shows the 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

8 In addition to the normal day-ahead market commitment, MISO utilizes the Multi-Day Forward Reliability Assessment Commitment process to commit resources in order to satisfy reliability requirements in certain load pockets that may require long-start-time resources.

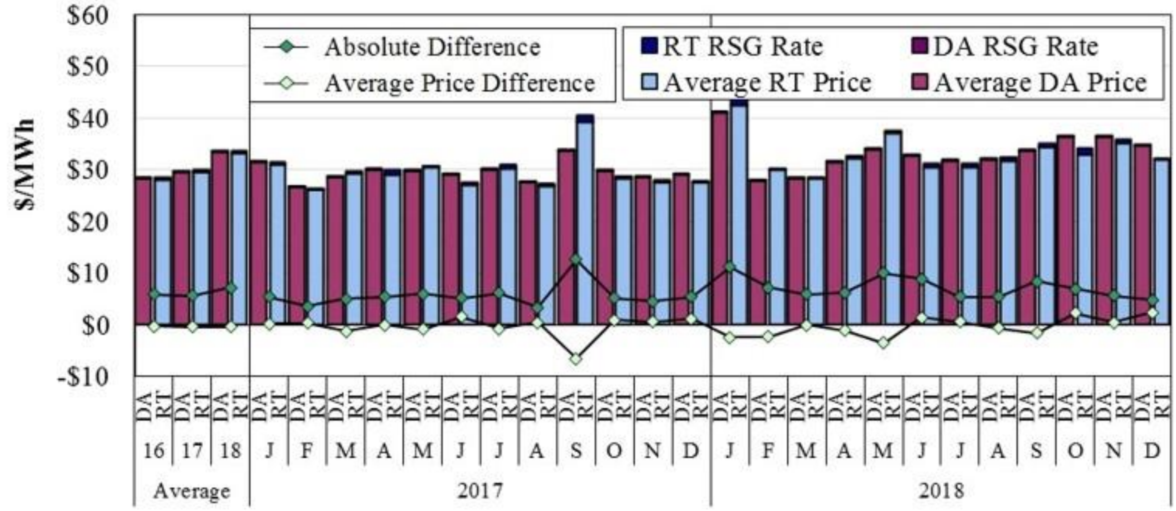
9 In addition, resources with day-ahead market schedules that are derated in real time or not following real-time instructions are subject to allocation of the Day-Ahead Deviation Charge (DDC) and Constraint Management Charge (CMC) as are virtual and physical transactions scheduled in the day-ahead market.

10 In between the day-ahead and real-time markets, MISO evaluates the day-ahead market results relative to the forecasted capacity needs for the next day. Based on this Forward Reliability Assessment Commitment (FRAC), MISO may send instructions for starting additional capacity not committed in the day-ahead market.

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 14: Day-Ahead and Real-Time Prices**

2017–2018




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

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

Day-ahead premiums were effectively zero on average after adjusting for the real-time RSG DDC, which averaged $0.64 per MWh. However, there were a number of congestion episodes that caused transitory divergence in different areas:

- Extremely cold temperatures and fuel price volatility throughout the footprint in early January contributed to high congestion and price volatility, including 14 intervals of operating reserve shortages with average prices of $501 per MWh.
- On January 17 and 18, MISO declared Maximum Generation Events and took several emergency actions in MISO South. The day-ahead premium at Louisiana Hub exceeded $1,100 per MWh for one hour on January 18 because emergency actions taken on both days resulted in lower real-time congestion.
- Record-high temperatures in late May led to challenging operating conditions, high prices, and high congestion. On May 29, MISO declared a Local Transmission Emergency in Michigan in order to commit emergency resources and access emergency ranges on online resources.
- On June 3, an operational issue caused overloads on a transmission facility in Louisiana and caused MISO to declare a Local Transmission Emergency. After 30 minutes of shortage, MISO raised the affected constraint's Transmission Constraint Demand Curve to $4,000 per MWh. This led to prices at Louisiana Hub in excess of $2,000 per MWh.

- On September 15, MISO declared an emergency in MISO South because of the loss of the largest generator and an unusually large day-ahead load forecasted error, which led to high prices at the Louisiana Hub. We describe this event in detail in Section III.

The day-ahead 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 them. We have recommended a virtual spread product that we discuss in the next section, which would allow a participant to more effectively arbitrage the congestion-related differences between the two markets.

## B. Virtual Transactions in the Day-Ahead Market

A large share of the liquidity that facilitates good day-ahead market performance is provided by virtual transactions. Virtual transactions are financial purchases or sales of energy in the day-ahead market that do not correspond to physical load or resources. As such, virtual day-ahead purchases or sales cannot perform in real time and, therefore, settle against the real-time price. Virtual transactions are essential facilitators of price convergence because they are used to arbitrage price differences between the day-ahead and real-time markets. Figure 15 shows the average offered and cleared amounts of virtual supply and virtual demand in the day-ahead market.

**Figure 15: Virtual Demand and Supply in the Day-Ahead Market**
2018

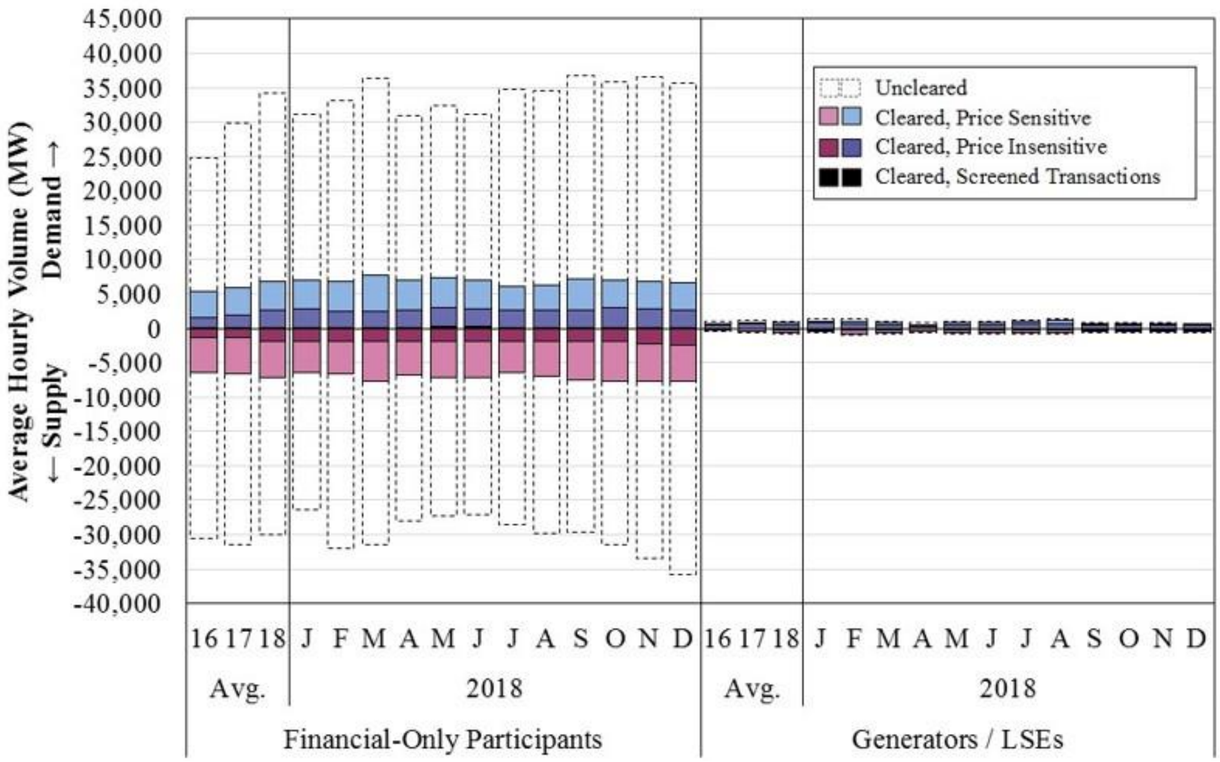


Figure 15 shows that average offered volumes increased by 4 percent over last year. Several market participants submit "backstop" bids, which are bids and offers priced well below (in the case of demand) or above (supply) the expected price range. Backstop bids and offers clear less than one percent of the time, but they are substantially profitable when they clear. These transactions are beneficial because they mitigate particularly large day-ahead price movements.

Average cleared transactions rose 11 percent, largely driven by financial-only participant activity. Financial participants account for the vast majority of virtual activity in MISO, as generators and LSEs typically participate in virtual transactions to hedge their generation or load positions. Financial participants, who tend to offer more price-sensitive virtual transactions than physical participants, provided key liquidity to the day-ahead market. They also continued to help moderate the effects of under-scheduling of wind in the day-ahead market.

Figure 15 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.[11] 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 2018 increased by 45 percent from 2017 to 1,675 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. We investigate these trades because they may be attempts to manipulate day-ahead prices. The screened transactions share was less than one percent and have not raised manipulation concerns.

11 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).

## C. Virtual Profitability

Gross virtual profitability was slightly lower in 2018, averaging $0.80 per MWh. As the volume of cleared virtual transactions increases, the virtual profits tend to decrease as price convergence improves. Virtual transactions by financial participants remained generally more profitable than transactions submitted by physical participants, averaging $0.82 per MWh compared to $0.51 per MWh. The fact that virtual transactions are profitable on average is good because profitable transactions generally promote convergence between day-ahead and real-time prices.

Virtual supply profitability rose 58 percent averaging $1.90 per MWh. In January, MISO declared Maximum Generation Events and took a number of emergency actions in the South that contributed to a high day-ahead premium in Louisiana. Gross profits are higher for virtual supply because more than half of these profits were 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."

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 improve day-ahead market outcomes.

## D. Benefits of Virtual Trading in 2018

We conducted an empirical analysis of virtual trading in MISO in 2018 that evaluated virtuals' contribution to the efficiency of the market outcomes. We determined that 58 percent of all cleared virtual transactions in MISO were efficiency-enhancing. We identified efficiency-enhancing virtual transactions as those that were profitable based on congestion modeled in the day-ahead and real-time markets and the marginal energy component (system-wide energy price). We did not include profits from un-modeled constraints or the loss factors because profits on these factors do not lead to more efficient day-ahead market outcomes.

We also identified a small amount (eight percent) of virtual transactions that were unprofitable but efficiency-enhancing because they led to improved price convergence. This happens when virtual transactions respond to a real-time price trend but overshoot, so they are ultimately unprofitable. Virtual transactions that did *not* improve efficiency are those that were unprofitable based on the energy and congestion on modeled constraints. Table 3 shows the percentage of efficient and inefficient virtual transactions by market participant type in 2018, as well as the average total MWhs of cleared virtual transactions by market participant type.

**Table 3: Efficient and Inefficient Virtual Transactions by Type of Participant**
2018

| | Total | Financial Participants | Physical Participants |
|---|---|---|---|
| **Efficient Virtuals** | 58% | 58% | 57% |
| **Inefficient Virtuals** | 42% | 42% | 43% |
| **Average MW per Hour** | 15,119 | 13,475 | 1,644 |

In reviewing the total profits and losses of the virtual transactions, we found that the profits of the efficiency-enhancing virtual transactions exceeded the losses of the inefficient transactions by $124 million in 2018, a 59 percent increase over 2017. This estimate 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 greatly beneficial in 2018.

Some have argued that virtual transactions can sometimes profit but not improve efficiency. We have identified these transactions and excluded them from the accounting above. The profits in this category include those associated with un-modeled constraints in the day-ahead market and differences in the loss components between the two markets. The net profits in this category totaled $46.5 million, of which 63 percent were due to discrepancies in modeling constraints between the day-ahead and real-time markets. It is important to note that these profits do not indicate a concern with virtual trading, but rather opportunities for MISO to improve the consistency of its day-ahead and real-time modeling.

# V. Real-Time Market Performance

The performance of the real-time market is very important because it governs the dispatch of MISO's resources and sends economic signals that facilitate scheduling in the day-ahead market and longer-term decisions. This section evaluates a number of aspects of the pricing and outcomes in the real-time market, including the uplift costs MISO incurs in operating the system.

## A. Real-Time Price Volatility

Substantial volatility in real-time energy markets is expected because the demands of the system can change rapidly and supply flexibility is restricted by the physical limitations of the resources and network. The day-ahead market operates on a longer time horizon with more commitment options and additional liquidity provided by virtual transactions. Because the real-time market is limited in its ability to anticipate near-term needs, the system is frequently "ramp-constrained" (i.e., some units moving as quickly as they can toward their optimal economic output). This results in transitory price spikes (upward or downward). Real-time price volatility in MISO fell by 26 percentage points at the Texas Hub and 18 percentage points at the Minnesota Hub in 2018. Figure 16 compares 15-minute price volatility at representative locations in MISO and in three neighboring RTOs.

**Figure 16: Fifteen-Minute Real-Time Price Volatility**
2018

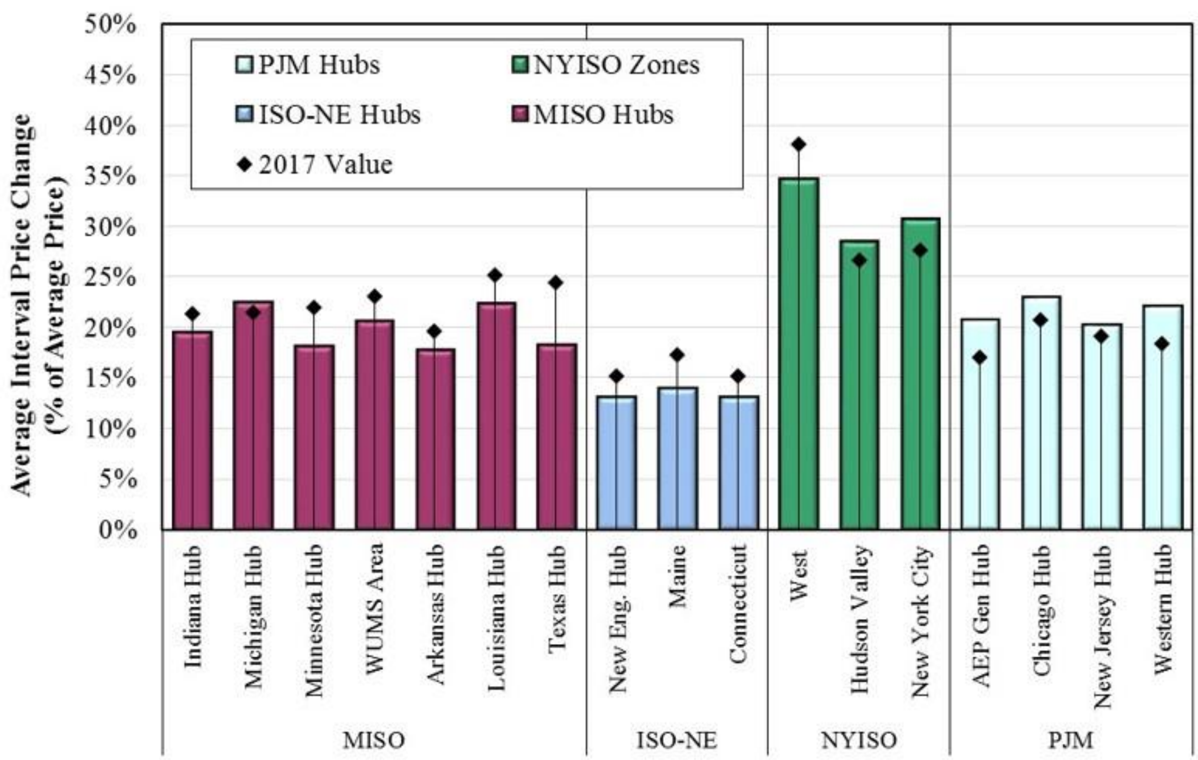


Figure 16 shows that MISO generally had lower price volatility than PJM and NYISO in 2018, which is impressive because:

- MISO runs a true five-minute real-time market (updating the dispatch each five minutes).
- PJM and ISO New England dispatch their systems every 10 to 15 minutes, which tends to provide more flexibility and lower volatility.
- NYISO dispatches the system every five minutes, like MISO, but it has a look-ahead dispatch system that optimizes multiple intervals that should reduce price volatility.

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;
- A large quantity of generation is either starting up or shutting down; 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.

## B. Evaluation of ELMP Price Effects

MISO implemented the Extended Locational Marginal Pricing algorithm (ELMP) in March 2015 and expanded the set of resources eligible to set prices in May 2017.[12] ELMP is intended to improve price formation by causing prices to better reflect the true marginal costs of supplying energy and ancillary services at each location. ELMP reforms pricing by allowing Fast-Start Resources[13] 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.

The first of these reforms was intended to remedy issues that we initially identified shortly after the start of the MISO energy markets in 2005 that can cause real-time prices to be substantially understated. This leads to substantial RSG costs and poor pricing incentives to schedule

12 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 2 extended participation to include resources with up to a one-hour start up time.

13 Fast-Start Resource is a term defined in the MISO Energy Markets Tariff as a "Generation Resource that can be started, synchronized and inject Energy, or a Demand Response Resource that can reduce its Energy consumption, within 10 minutes of being notified and that has a minimum run time of one hour or less…."

generation and interchange. Although they may not appear to be marginal in the 5-minute dispatch, the ELMP model recognizes that inflexible peaking resources are marginal and should set prices to the extent that are needed to satisfy the system's needs.

The second reform allows *offline* fast-start resources to set prices under transmission and reserve shortage conditions. In theory, it is efficient for offline resources to set the price 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 set energy prices, the resulting prices will be inefficiently low.

ELMP had a modest effect on MISO energy prices in 2018, increasing the market-wide real-time prices by only ***$0.72*** per MWh on average overall, up from $0.13 per MWh in 2017. It had larger effects at certain congestion locations – the average effects ranged from -$1.24 to $9.87 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. To evaluate the effectiveness of ELMP, we separately assess the online and offline aspects of ELMP in the subsections below.

### *Evaluation of Online Pricing*

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 2 in May 2017. Even with this change, the online pricing in ELMP only increased average real-time prices by $0.84. Although we are recommending further expansion of eligibility, we also evaluated a key assumption in ELMP that determines *how* resources participate in ELMP.

ELMP does not allow resources to set prices when the dispatch model desires to ramp them down at their maximum ramp rate. This ramp test substantially reduces the resources that qualify as marginal price-setting resources. In both the ISO-NE and NYISO variants of ELMP, a resource may be considered marginal and set prices unless it is dispatched to zero. This is a significant advantage over MISO's ELMP approach, which we evaluate below in Table 4.

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

| Alternative ELMP Methods | Avg. Price Increase ($/MWh) | % of Fast-Start Peaker Eligible | % of Intervals Affected |
|---|---|---|---|
| Current Phase II | $0.58 | 6.8% | 11.4% |
| *Plus Day-Ahead Units* | $1.31 | 12.5% | 23.1% |
| *No Ramp Limitation* | $2.02 | 13.7% | 27.7% |
| *Plus DA Units & No Ramp Limit* | $2.77 | 28.5% | 32.6% |

Although an improvement, Phase 2 only allows 6.8 percent of MISO's peaking units to set prices, so the effects have been modest. In past reports, we recommended that MISO extend eligibility to units scheduled in the day-ahead market, which would increase participation to 12.5 percent of the peaking output. We recommend that MISO relax the ramp limitations for units in the ELMP model to better determine whether the fast-start units are needed to satisfy the system's needs.

The table above shows that including day-ahead scheduled resources would have more than doubled ELMP's effectiveness to an average increase of $1.31, while also relaxing the downward ramp limitation on the peaking resources would double it again to $2.77 per MWh. This represents an average real-time price increase throughout MISO ranging from 10 to 15 percent in peak hours and larger increases on days when MISO is heavily relying on peaking resources. This will have large beneficial effects on high-load days, improving the commitment of resources and the scheduling of imports and exports. Hence, we continue to recommend these reforms as among the highest priority improvements for MISO.

### *Evaluation of Offline ELMP Pricing*

We have evaluated the offline pricing during transmission violations and operating reserve shortages, when ELMP sets prices based on the hypothetical commitment of an offline unit that MISO could theoretically have utilized to address the shortage. This is only efficient when the offline resource is: a) feasible to address the shortage, and b) economic to commit. When units set prices that do not meet these criteria, the resulting prices will be inefficiently low.

When an offline unit is both feasible and economic, one would expect the unit will usually be started by MISO. When resources are not started, we infer that a) the operators did not believe the unit could be online in time to help resolve the shortage, and/or b) that the operator did not expect that the unit would be economic to operate for the remainder of its minimum runtime. Therefore, our evaluation quantifies how frequently the offline resources that set prices are actually started by MISO operators, and how frequently they are actually economic in retrospect based on MISO's ex ante real-time prices. Table 5 below summarizes our results.

**Table 5: Evaluation of Offline ELMP Price Setting in 2018**

| | Economic* | Started | Economic & Started |
|---|---|---|---|
| Operating Reserve Shortages | 10% | 13% | **3%** |
| Transmission Shortages | 15% | 2% | **1%** |

**Does not include units that were never started, which would increase the values to: 13% for OR shortages and 26% for Tx shortages.*

This table shows that the offline units that set prices during both operating reserve and transmission shortages even though they are rarely economic and feasible (3 and 1 percent of intervals, respectively). Based on these results, we conclude that ELMP's offline pricing component is not satisfying the economic principles outlined above and is undermining price formation during shortage conditions. As the Commission has recognized, efficient shortage pricing is essential, so we recommend that MISO disable the offline pricing logic.

## C. Evaluation of Shortage Pricing in MISO

Virtually all shortages in RTO markets are of operating reserves (i.e., RTOs will hold less reserves than its requirement rather than not serving the energy demand). In recent years, MISO has experienced several capacity shortage events, which we discuss in Section III. When an RTO is short of operating reserves, the value of the foregone reserves should set the price for the reserves and be embedded in all higher-value products, including energy. This value is established in the operating reserve demand curve (ORDC) 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 operating reserve shortages.

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 the load that may not be served. 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 reflect the value of reserves because:

- Only a small portion of the curve is based on the probability of losing load – over 90 percent of the current ORDC is set by administrative overrides of $200 and $1,100; and
- MISO's current VOLL of $3,500 is understated.

Figure 17 shows the current ORDC represented by the black dotted line, the MISO-proposed ORDC after implementation of FERC Order 831 in the fall of 2020, represented by the red line, and a blue curve that illustrates the IMM's proposed economic ORDC. Small shortages of less than four percent are priced at the lowest step of $200. As reserve levels fall (and shortages increase), the current ORDC will continue to price the shortage at $1,100, even though the probability of losing load is increasing. The single step to $2,100 in the MISO-proposed ORDC is intended to be consistent with FERC's Offer Cap rule.[14]

14 FERC RM16-5-000, Order No. 831, issued November 17, 2016.

In comparison, the IMM's economic ORDC better reflects the expected value of lost load, which we illustrate in Figure 17 based on an assumed VOLL of $12,000 per MWh. We estimated the probability of losing load using a Monte Carlo simulation.[15] The figure also shows that in MISO almost all actual shortages have been modest and priced in the green range shown on the figure.

**Figure 17: Comparison of IMM Economic ORDC to Current ORDC**

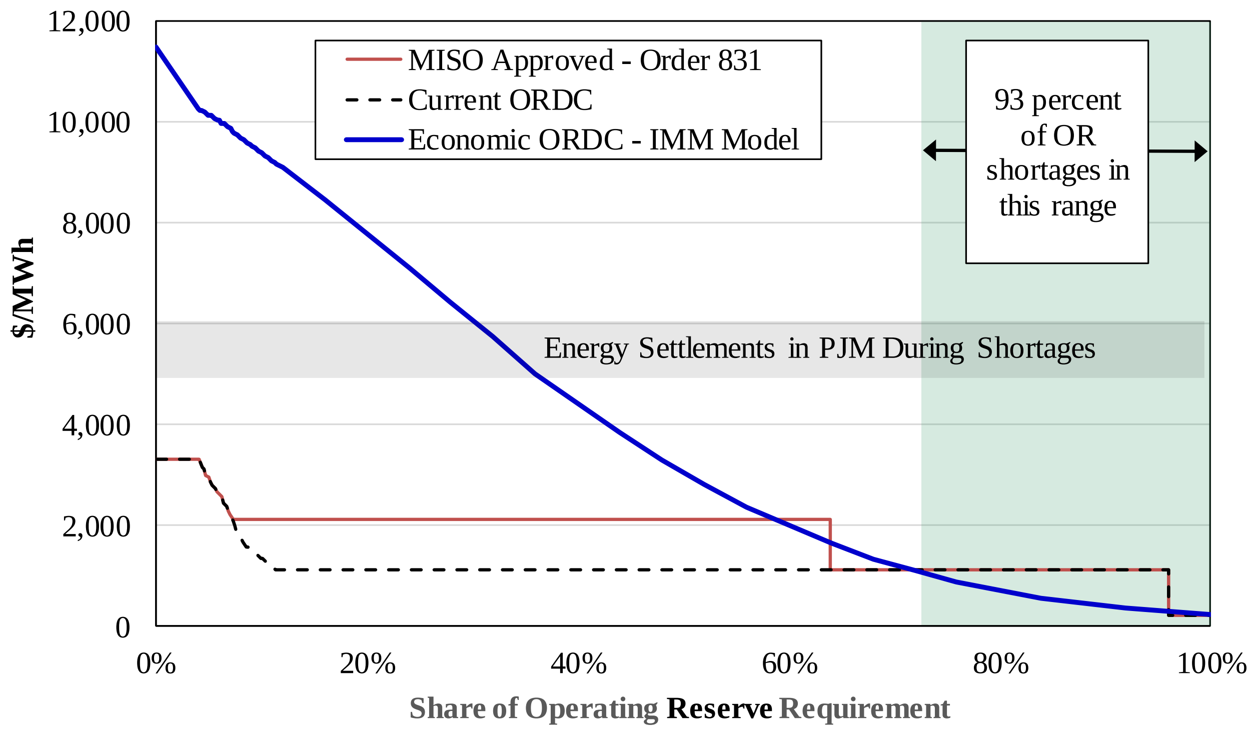


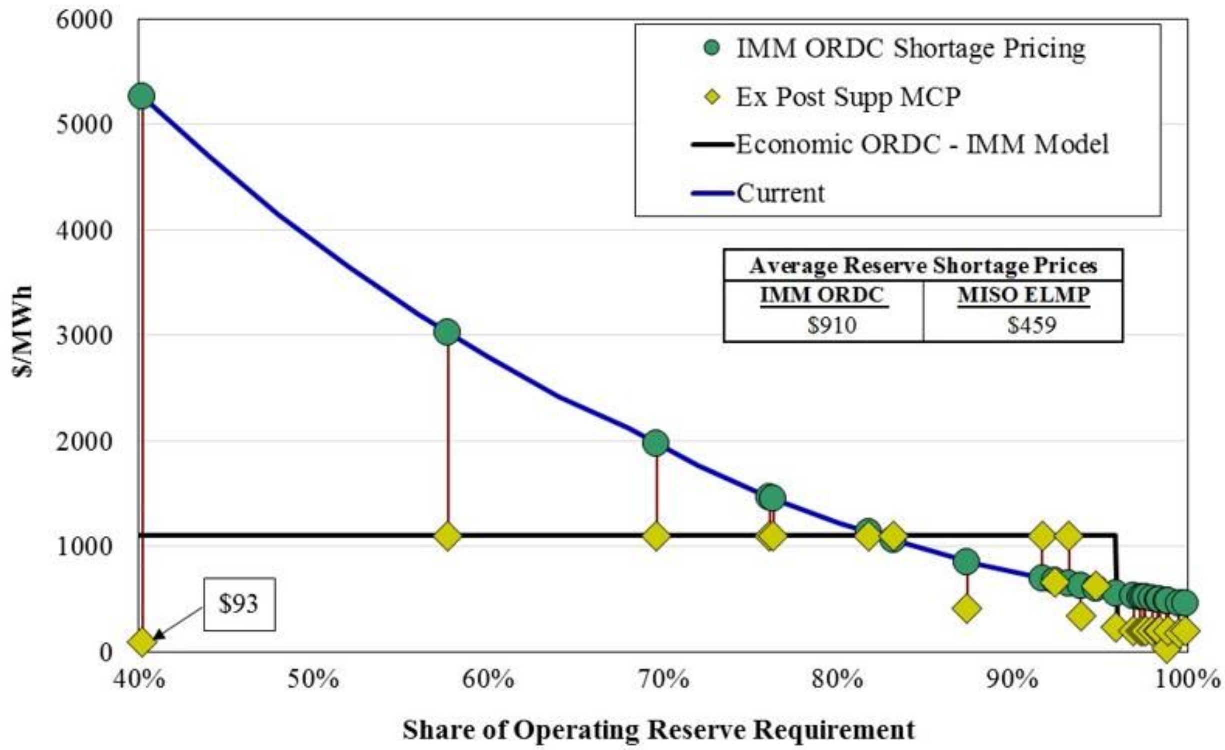

Figure 17 shows that the current curve used in MISO will set inefficiently high shortage prices under some conditions and inefficiently low shortage prices under others. The sharp increase in the curve at 96 percent of MISO's reserve requirement leads to excessive price volatility at low shortage levels. An economic ORDC aligns shortage pricing with the marginal reliability value of the foregone reserves. This will result in more efficient economic signals that govern both short-term and long-term decisions by MISO's participants.

### *Evaluation of Actual Pricing of Operating Reserve Shortages*

In addition to evaluating the ORDC, we assessed the shortage pricing that actually occurred during the contingency reserve shortages in MISO in 2018. Figure 18 provides our results comparing the MISO's actual pricing during shortages (labeled "ELMP Pricing") with the pricing that would occur under an economic ORDC (labeled "IMM Pricing). We truncated the curve to highlight the part of the ORDC where shortages actually occurred in 2018.

15 The simulation estimated the conditional probabilities across 10,000 iterations, which is described in Section V.F of the Analytic Appendix.

**Figure 18: Comparison of Actual Shortage Pricing to IMM ORDC Shortage Pricing**
2018



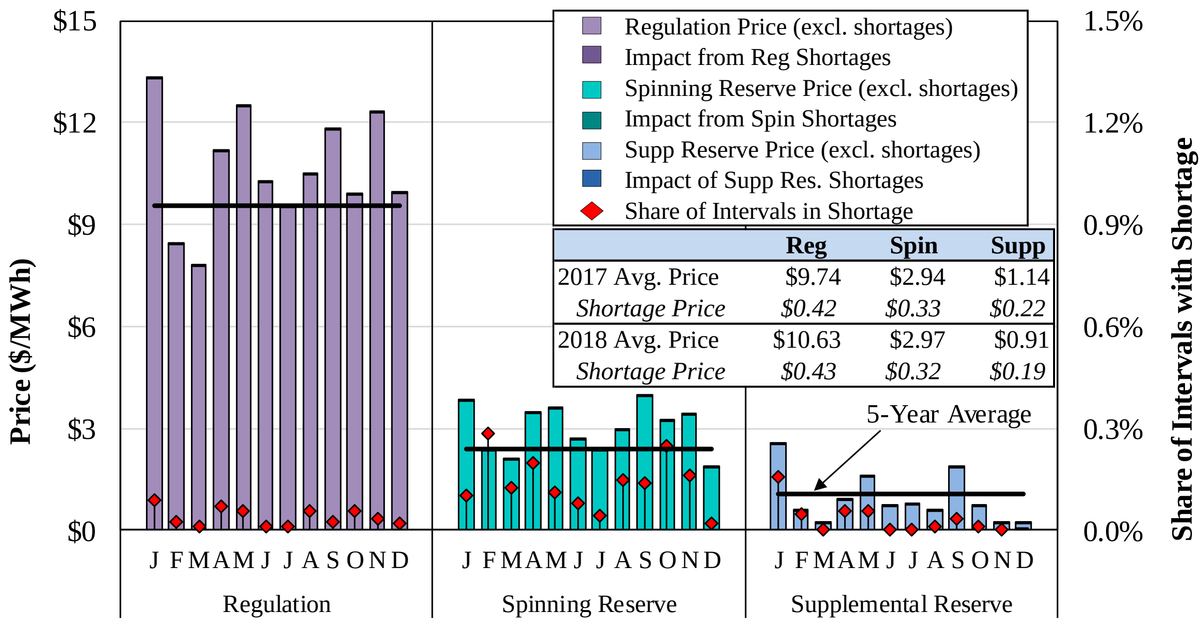

In 2018, MISO experienced a total of 33 operating reserve shortages. In nearly one-third of these intervals, ELMP artificially depressed the shortage prices. The figure shows that the average shortage pricing under an economic ORDC would have been almost 60 percent more than occurred under the ELMP model.

We continue to find that the offline ELMP methodology is artificially suppressing shortage pricing and, by doing so, adversely affecting the short and long-term decisions guided by these prices. Therefore, we continue to recommend that the offline ELMP pricing be disabled.

## D. Ancillary Services Markets

Since their inception in 2009, co-optimized ancillary services markets have produced significant benefits, leading to improved flexibility and lower costs of satisfying the system's reliability needs. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions. For each product, Figure 19 shows monthly average real-time prices, the contribution of shortage pricing to each product's price in 2018, and the share of intervals in shortage. MISO's demand curves specify the value of all of its reserve products. When the market is short of one or more of its reserve products, the demand curve for the product will set the price and also be included in the prices of higher-valued reserves and energy through the co-optimized market clearing.

**Figure 19: Real-Time ASM Prices and Shortage Frequency in 2018**




The supplemental reserves only contribute to meeting the market-wide operating reserve 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.[16]

Figure 19 shows that average clearing prices for regulation and spinning reserves rose slightly, largely because of the increase in gas prices, while prices for supplemental reserves fell slightly.

## E. Settlement and 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 all of 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:

- 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 ensure suppliers will not be financially harmed by following the five-minute dispatch signals.

16 The demand curve for regulation, which is indexed to natural gas prices, averaged $140.58 per MWh in 2018, down from $162.77. 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%). MISO's total Operating Reserve Demand Curve is shown in subsection C above.

Resources committed before or in the day-ahead market receive a day-ahead RSG payment as needed to recover their costs. Resources committed by MISO after the day-ahead 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.

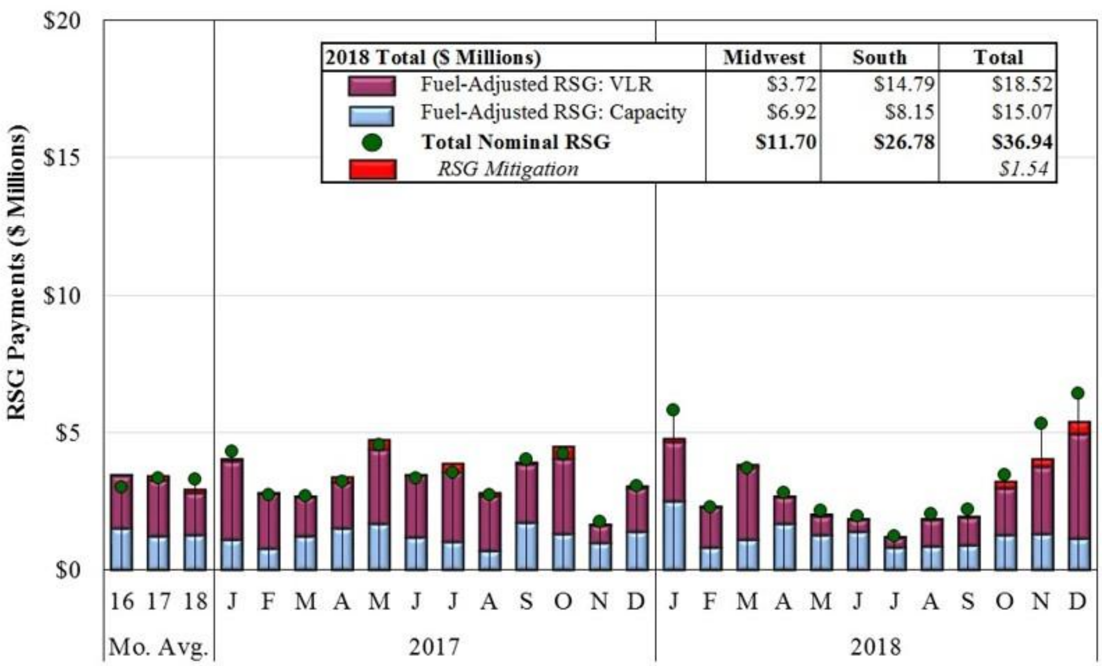
### *Day-Ahead and Real-Time RSG Costs*

Figure 20 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.[17] The maroon bars show the RSG paid to units started before the day-ahead market for VLR.

Nominal day-ahead RSG costs fell by 2 percent. However, they fell 14 percent on a fuel price adjusted basis because fuel prices were much higher in the second half of 2018. During the summer, day-ahead RSG payments fell by 44 percent, driven by significantly lower costs of managing VLR requirements in the South. Transmission upgrades in the Western Load pocket led to more than a 60 percent drop in day-ahead RSG for VLR commitments in the summer.

**Figure 20: Day-Ahead RSG Payments**

2017–2018



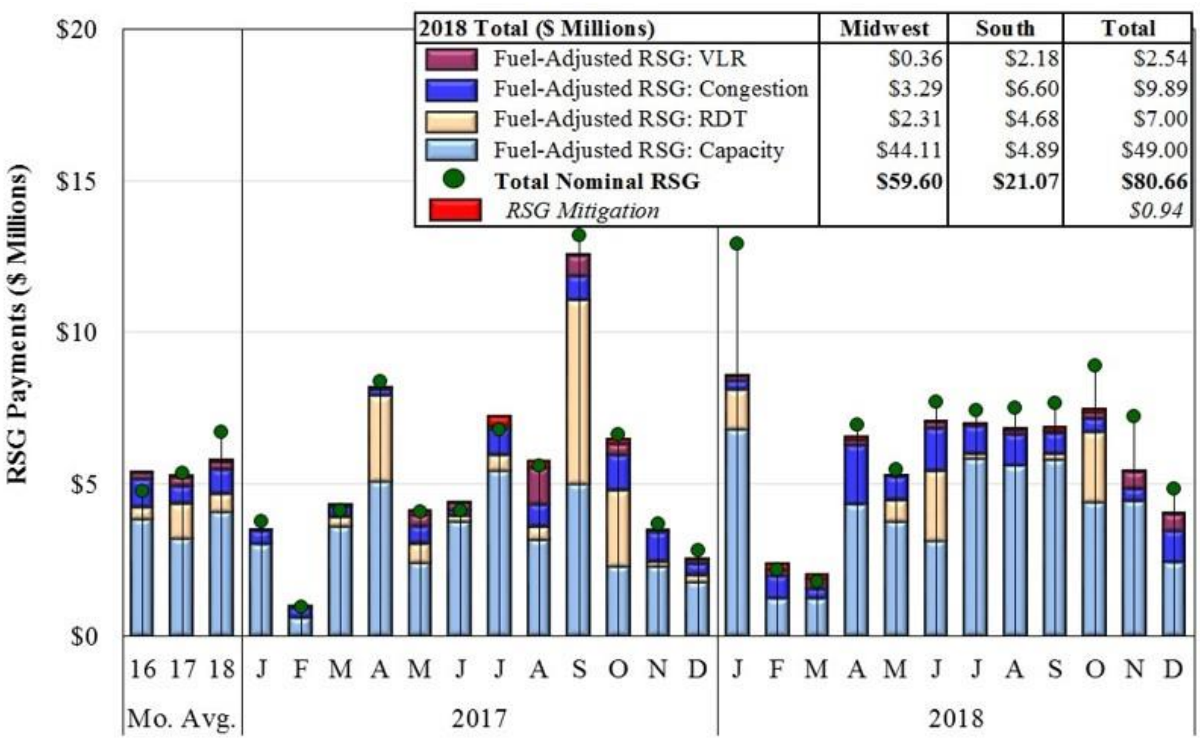

17 Fuel-adjusted RSG payments are indexed to the average three-year fuel price of each unit. Downward adjustments are, therefore, greatest for periods when fuel prices were highest and vice versa.

In 2016, MISO completed construction of several transmission projects in the South subregion load pockets that reduced the need for some VLR commitments. Nonetheless, if one includes the RSG associated with day-ahead market commitments likely made to satisfy the VLR constraint, 44 percent of all day-ahead RSG payments were caused by VLR needs in the South.

Figure 21 shows the same monthly RSG payments from the real-time market. This figure shows that nominal average real-time RSG payments rose 26 percent in 2018, largely driven by higher fuel prices. Adjusting for changes in fuel prices, real-time RSG increased by 10 percent in 2018. In the summer quarter, real-time RSG rose by 43 percent, partially attributable to MISO implementing a new reliability requirement in MISO South. Additionally, RSG that was paid for constraint management and RDT commitments during the summer more than doubled over summer 2017.

The figure also shows that overall RSG payments associated with the RDT fell substantially in 2018. In August 2018, FERC issued an order[18] granting MISO mitigation authority for resources committed in MISO South for the RDT. MISO's filing and FERC's subsequent acceptance of the proposed Tariff changes addressed concerns that we raised in last year's *State of the Market Report* regarding these types of commitments.

**Figure 21: Real-Time RSG Payments**
2017–2018



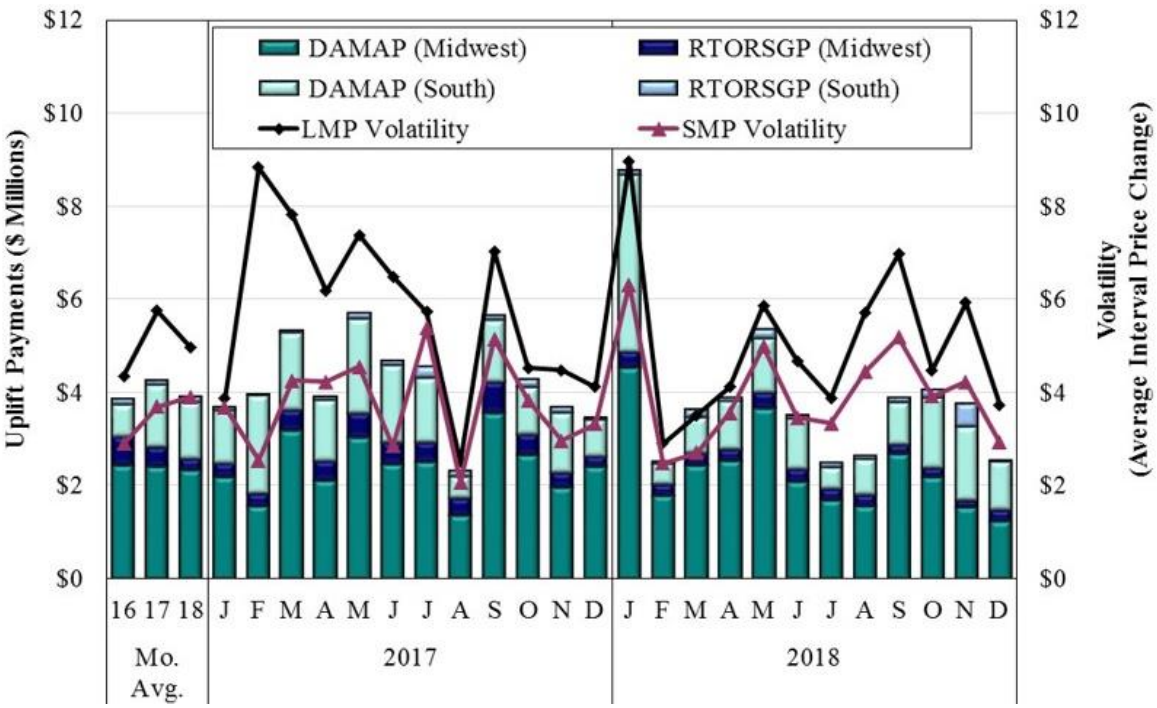

18 "Order Accepting Tariff Revisions re Midcontinent Independent System Operator, Inc. under ER18-1464," ER18-1464, August 23, 2018.

We have recommended that MISO implement a regional 30-minute reserve product to allow the markets to procure the resources needed to satisfy these regional requirements as well as the VLR requirements that result in substantial day-ahead RSG costs. MISO is working to implement such a product, which is scheduled for implementation in 2021. In the meantime, MISO has implemented the Reserve Procurement Enhancement (RPE) to the RDT. This should allow MISO's market commitments to better satisfy these needs. In the longer-term, pricing these reserve requirements will provide efficient incentives for participants to invest in fast-starting generation that is well-suited to satisfy the requirements. Finally, we are recommending expanding the eligibility for fast-start units to participate in ELMP and other changes to make it more effective, which will lower real-time RSG (see Section V.B for more detail).

### *Price Volatility Make-Whole Payments*

PVMWPs address the concerns that resources that respond flexibly to volatile five-minute price signals can be harmed. 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 Payment (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**
2017–2018



The figure shows that the PVMWP levels decreased by 8 percent in 2018, generally because of lower LMP volatility in 2018, particularly during the summer. In January, extremely cold temperatures led to fuel price volatility and emergency events. These factors all contributed to highly volatile SMPs and LMPs – 20 percent of all DAMAP was paid in that month. In May, record-high temperatures contributed to challenging operating conditions and volatile prices, which led to increased DAMAP. On July 1, MISO implemented five-minute settlements that eliminated some payments previously made related to hourly settlements. As part of this change, MISO corrected a flaw that had resulted in unjustified DAMAP for wind units. These changes will lead to lower price volatility make-whole payments going forward.

Although PVMWPs play an important role in MISO's market, we continue to be concerned that a large share of the DAMAP is paid to units running at uneconomic output levels because they are not following dispatch instructions or because State Estimator model errors cause MISO to issue dispatch instructions that are less than optimal at some locations. To evaluate this concern, Table 6 shows the total DAMAP paid in 2018 subdivided by the following causes:

- Resources following their dispatch instructions;
- Resources appearing to deviate from MISO's dispatch instructions because of State Estimator (SE) Error;
- Resources deviating from MISO's dispatch instructions by more than the new deviation thresholds;
- Resources deviating from MISO's dispatch instructions by less than the new deviation thresholds; and
- Wind resources that were receiving unjustified DAMAP because of forecast errors.

**Table 6: Causes of DAMAP in 2018**

| Item Description | DAMAP ($ Millions) | % Share |
|---|---|---|
| **Following Instruction** | $31.1 | 74% |
| **SE Issue** | $1.1 | 3% |
| **Inferred Derate** | $0.1 | 0% |
| **Dragging - Failing New Threshold** | $2.8 | 7% |
| **Wind Unjustified** | $1.3 | 3% |
| **Dragging - Not Failing New Threshold** | $5.4 | 13% |
| **Total** | $41.9 | 100% |

Note: Excluded Hour Beginning 0 in the Analysis

The table shows that $1.3 million of the DAMAP were unjustified payments to wind resources that over-forecasted their output, down from $2.7 million in 2017. These resources were previously eligible to receive DAMAP because of a flaw in the MISO Tariff that was remedied on July 1, when MISO transitioned to five-minute real-time settlements.

Table 6 also shows that more than 25 percent of the DAMAP was paid to resources that were not fully following MISO's dispatch instructions. In fact, while DAMAP does provide an incentive to be flexible, it also holds generators harmless for poor performance.  In other words, it allows generators to avoid the economic consequences of poor performance.  We have also identified a number of gaming strategies participants can employ to acquire unjustified payments.

To address these issues, we have recommended the reform of these payments.  MISO implemented reforms in December 2018 and May 2019 that will improve the calculation of the PVMWPs and the uninstructed deviation thresholds, which should substantially reduce the unjustified PVMWPs and improve generator performance.

## F. Regional Dispatch Transfer Flows and Regional Reliability

Since the integration of the South into MISO, the 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 recommended that MISO introduce a 30-minute reserve product for each region.  MISO will be filing this “Short-Term Reserve” product in 2019, but it will not likely be implemented until 2021.

Importantly, when higher levels of interregional transfers do not contribute to congestion on the Joint Parties’ systems, incurring substantial costs to limit the transfers can be inefficient.  To reduce these inefficient costs in managing the transfers with the RDT, we recommend that MISO allow the Joint Parties to sell operating reserves with the transmission capacity on the RDT above the RDT limit.  MISO could then compensate the Joint Parties by paying them the clearing price for subregional reserves, as well as paying for the deployment of the reserved transmission (equal to the $500 per MW RDT demand curve level times the deployment quantity).

Under this approach, the Joint Parties would have been compensated $3.25 million during the emergency events that occurred on January 17-18, 2018.  This payment would provide reasonable compensation to the Joint Parties for the excess transfers that may occur under emergency conditions.

## G. Generator Dispatch Performance

MISO sends energy dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval.  MISO had assessed penalties for deviations from this instruction when deviations remain outside of an eight-percent tolerance band for four or more consecutive intervals within an hour in 2018, but a new tolerance band is being implemented in 2019.[19]  The purpose of the tolerance band is to permit deviations to

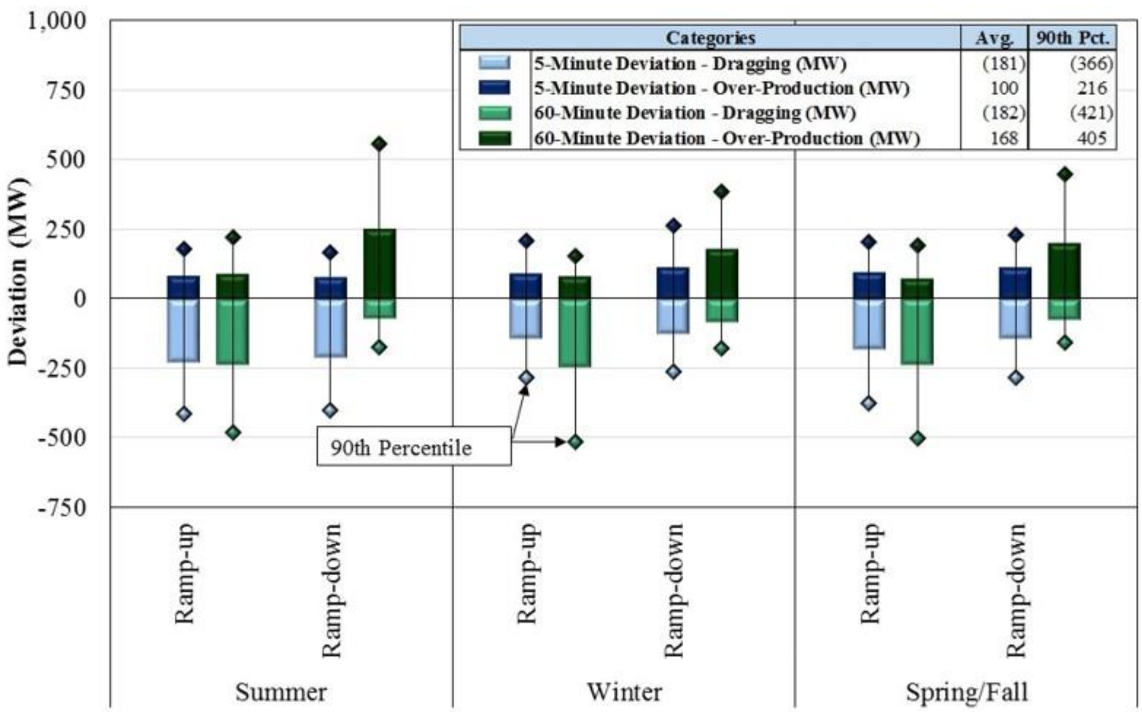
19 See Tariff section 40.3.4.a.i.  The tolerance band can be no less than six MW and no greater than 30 MW.

balance the physical limitations of generators with MISO's need for units to follow dispatch instructions. MISO's uninstructed deviation threshold had been significantly more lenient than most other RTOs' and contributed to poor performance by some suppliers. In addition, MISO's real-time operators are responsible for identifying resources that are performing poorly.

Figure 23 shows the size and frequency of two types of net deviations by season in ramp-up and ramp-down hours when the impact of deviations are most severe on both pricing and reliability:

- Five-minute deviation: the difference between MISO's dispatch instructions and the generators' responses in each interval.
- 60-minute deviation: the difference between energy the unit is actually producing and what it would be producing had it followed dispatch over the prior 60 minutes.[20]

**Figure 23: Average Five-Minute and Sixty-Minute Net Deviations in 2018**




This analysis shows the average five-minute deviations are slightly higher in the morning ramp-up hours. However, the 60-minute dragging deviations are much higher in these hours, averaging more than 180 MW (more than 7 percent of MISO's total reserve requirement). This continues to raise substantial concerns because much of this capacity is effectively unavailable to MISO since the resources are not following the dispatch instructions. Further, 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.

20 The methodology for calculating the 60-minute deviation is described in Section V of the Analytic Appendix.

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 improving the settlement rules that address poor generator performance. Hence, we had recommended that MISO:

- Improve the tolerance bands for uninstructed deviations (i.e., Deficient 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.

In October, MISO filed proposed Tariff changes to address these recommendations.[21] FERC approved these changes in January 2019 and they were implemented in May 2019. Additionally, MISO implemented a new procedure in early 2018 to receive alerts from the IMM that identify resources with large 60-minute dragging deviations that may be derated. 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.

## H. Evaluation of 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) if 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:

- Decreases in the offset by 600 MW or more corresponds to an average decrease in SMP of more than $40; and
- Increases in offsets of greater than 600 MW corresponds to an average SMP rise of $65.

We monitor offset values because large changes, although infrequent, can sometimes contribute to price spikes or mute legitimate shortage pricing. In 2018, MISO implemented additional

21 Docket No. ER19-199-000.

logging information on offset choices and has a project planned under the Market Systems Enhancements to improve the offset determinations. We encourage MISO to continue its efforts to improve the tools used to recommend offset values and the logging of the offset choices.

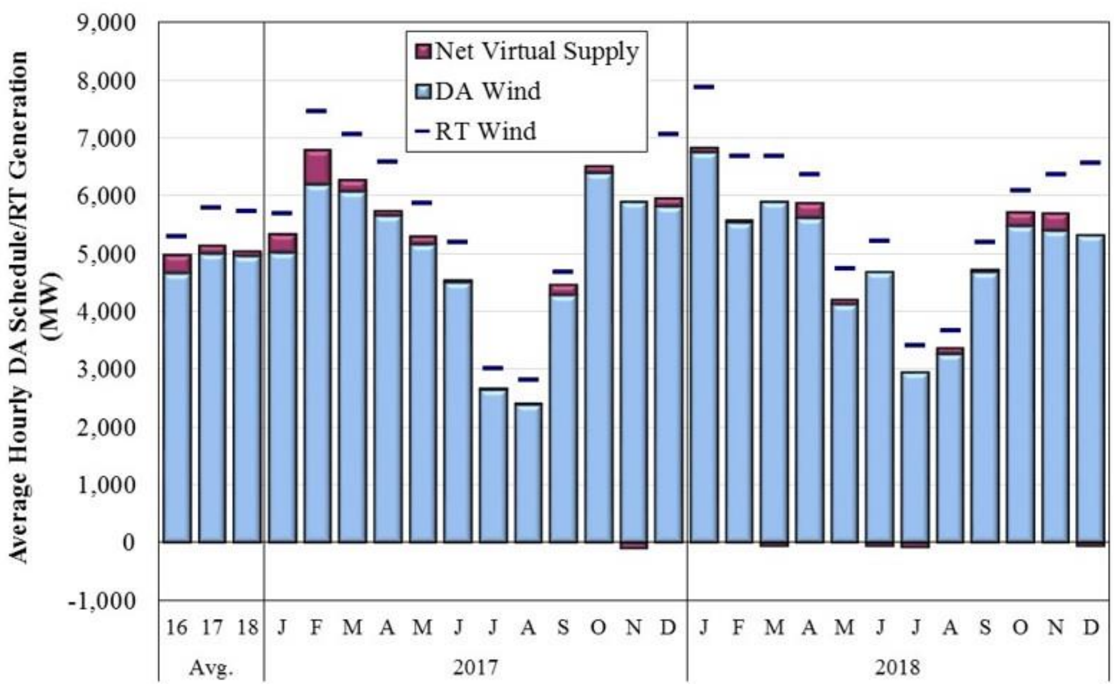
## I. Wind Generation

Installed wind capacity now exceeds 19 GW and accounted for 8 percent of generation in 2018. In 2018, 1.9 GW of wind capacity entered MISO and we expect development to continue as long as tax incentives exist.[22] Although wind generation promises substantial environmental benefits, its output is intermittent and presents operational challenges. These challenges are amplified as wind's share of total output increases.

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

Figure 24 shows the average monthly amount of wind output scheduled in the day-ahead market compared to the actual real-time wind output. It also shows the amount of virtual supply scheduled on average at wind locations and the Minnesota hub, which is close to many of MISO's wind resources. In prior years, the virtual supply tended to compensate for under-scheduling by wind suppliers in the day-ahead market, but this response has fallen since 2016.

**Figure 24: Day-Ahead and Real-Time Wind Generation**
2017–2018




22 In December 2015, Congress extended the investment tax credits (ITCs) and production tax credits (PTCs) for wind projects. Wind projects that began construction in 2015 or 2016 received either 30 percent ITCs or $23 per MWh in PTCs. Given the high capacity factors of wind units, most new wind suppliers chose the PTC. The credit falls 20 percent each year for units that begin construction from 2017 through 2019.

Average real-time wind generation in MISO decreased slightly in 2018 to 5.7 GW per hour. However, MISO set several all-time wind records in 2018 and early 2019, the last of which was March 15, 2019 at 16.3 GW. We expect this trend to continue as more wind resources are added to the system. The figure shows that wind output is substantially lower during summer months than during shoulder months, which reduces its reliability value to the system.

Figure 24 also shows that wind suppliers often schedule less output in the day-ahead market than their real-time output. This can be attributed to some of 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. This convergence issue is often partially addressed by virtual suppliers that sell energy in the day-ahead market in place of the wind suppliers. Under-scheduling of wind averaged 770 MW per hour and exceeded 1,000 MW in three months.

As total wind capacity continues to grow, the operational challenges will grow related to output volatility and congestion that must be managed by MISO. Sharp reductions in output can lead to substantial price volatility and require MISO to make real-time commitments to replace lost output. MISO has been evolving to address these challenges, including the introduction of the ramp product in 2016. Improving shortage pricing will be an essential component of this evolution. In 2018, MISO began studying the potential implications of differing wind/solar penetration levels under the Renewable Integration Impact Assessment (RIIA).[23]

The concentration of the wind resources in the western areas of MISO's system has also 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 this volatility. 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).

### *Wind Forecasting*

In 2017, we identified significant concerns with certain wind resources that frequently and substantially over-forecast their wind output in real time. The wind forecasts are important because MISO uses them to establish wind resources' economic maximum in the real-time energy market. Because wind resources offer at prices lower than any other resources, the forecasted output also typically matches the MISO dispatch instruction, absent congestion. Because an over-forecasted resource will produce less than the dispatch instruction, this will result in dispatch deviations. Figure 25 shows the monthly average quantity of the dispatch deviations from the wind resources (in the bars), as well as the average forecast error plotted as a line against the right y-axis in 2017 and 2018.

23 See documents at: https://www.misoenergy.org/planning/transmission-studies-and-reports.

**Figure 25: Generation Wind Over-Forecasting Levels**
2017–2018

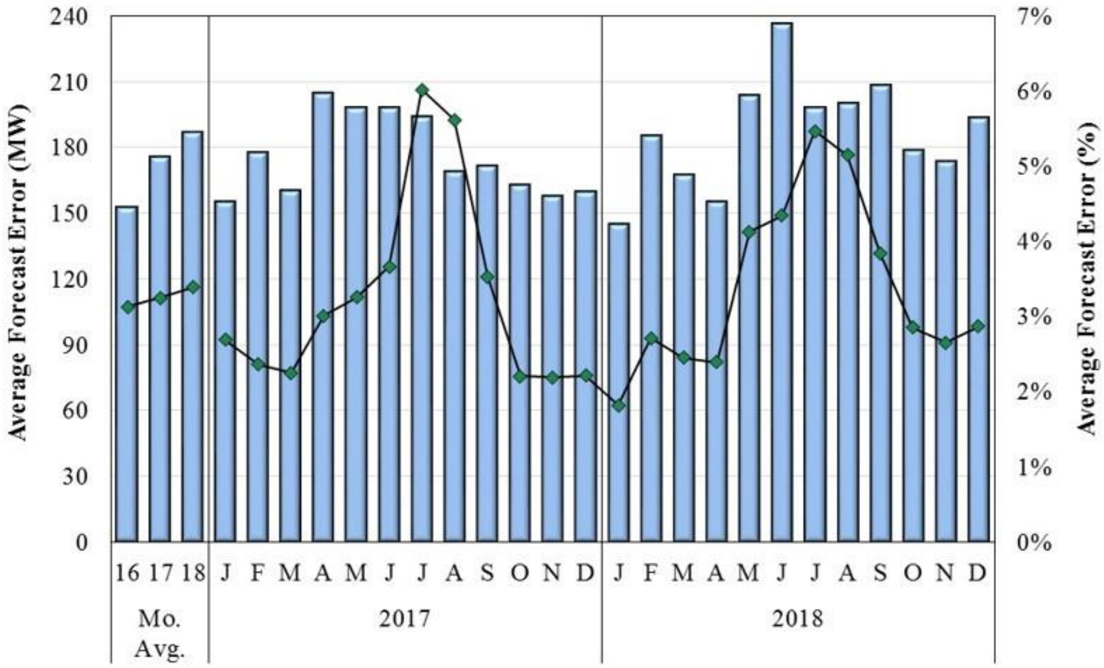



Figure 25 shows that wind resources in aggregate consistently over-forecast their output capability. The over-forecasting rate is much higher in the summer months even though the wind output tends to be lower in these months. We believe these patterns are consistent with incentives provided by the MISO market rules. We identified two primary factors that have contributed to wind over-forecasting, both of which have been remedied.

The first issue was a Tariff flaw that allowed wind resources to receive unintended DAMAP when they are dispatched at their economic maximum. Resources are only intended to receive DAMAP when they are dispatched below their economic maximum. MISO's five-minute settlement reforms went into effect on July 1, 2018 and addressed this flaw.

Second, MISO's changes to its uninstructed deviation thresholds and PVMWP formulas described above improved wind suppliers' incentives to forecast its output accurately or, alternatively to use the MISO forecast. These changes went into effect in May 2019 and we will be evaluating the changes in the wind forecasting accuracy.

However, we recommend that MISO review and validate wind forecasts in real time. This validation would allow MISO to replace participants' forecasts when they are consistently shown to be biased in the over-forecast direction. MISO has begun periodically evaluating participant forecasts and plans to determine whether new procedures and the authority to replace participants' forecasts are warranted.

# VI. Transmission Congestion and FTR Markets

To avoid overloading transmission constraints, MISO's markets manage flows over the network by altering the dispatch of its resources and establishing efficient, location-specific prices that represent the marginal costs of serving load at each location. Transmission congestion arises when network constraints prevent MISO from fully dispatching the lowest-cost units, so higher-cost units must be dispatched in their place. This "out-of-merit" cost is reflected in the congestion component of MISO's locational prices.[24] The congestion component can vary widely across the system, raising LMPs in "congested" areas where generation relieves the constraints and lowering LMPs in areas where generation loads the constraints.

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

## A. Real-Time Value of Congestion in 2018

We calculate the value of real-time congestion by multiplying the flow over each constraint by the economic value of the constraint (i.e., the "shadow price"). This metric indicates the congestion that occurs as MISO dispatches its system. Figure 26 shows the monthly real-time congestion values in 2017 and 2018.

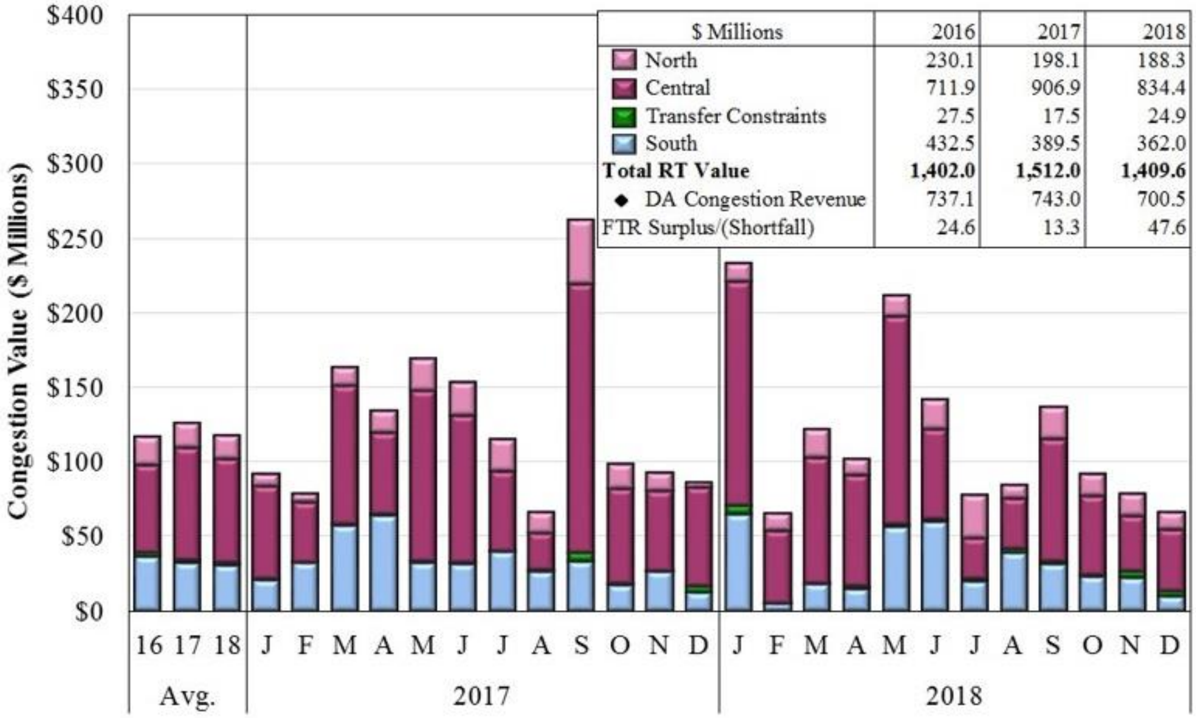
The value of real-time congestion fell by 6.8 percent from last year to $1.4 billion. Congestion tends to track natural gas prices because natural gas-fired units are generally dispatched to manage the power flows over binding constraints. The higher natural gas prices in 2018 would have led to congestion increasing from 2017, except that 2017 experienced unusually severe congestion in September. In 2018, transient conditions contributed to episodes of higher real-time congestion in January and May:

- In January, MISO incurred $162 million in real-time congestion in the Midwest and $64.5 million in the South, accounting for 16 percent of the total annual congestion. High gas price volatility early in the month, record-high wind output, and emergency conditions in the South contributed to this congestion.
- In late May, record-high temperatures and transmission outages contributed to high prices and congestion. Nearly 10 percent of the total congestion in the spring occurred on the last three days of May, with $33 million of congestion on a single day.

In most other months, congestion was lower in 2018 because of lower natural gas prices in the spring of 2018 and improvements in market-to-market coordination.

24 The marginal congestion component, or "MCC," is one of three LMP components, which also includes a marginal energy component and a marginal loss component.

**Figure 26: Value of Real-Time Congestion and Payments to FTRs**
2017–2018




The real-time congestion that occurred in 2018 and prior years is higher than optimal because several key issues continue to hinder congestion management in MISO. These issues are each discussed in this section and include:

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

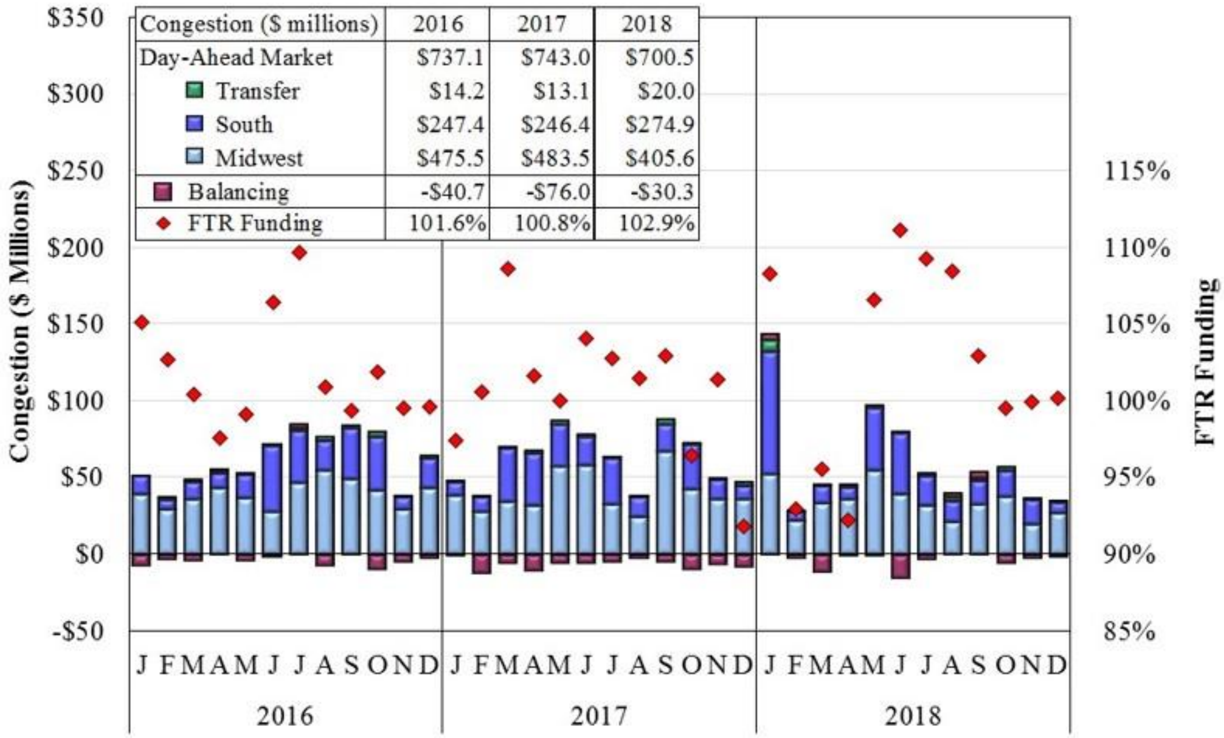
## B. Day-Ahead Congestion Costs and FTR Funding in 2018

MISO's day-ahead energy market is designed to send accurate and transparent locational price signals that reflect congestion and losses on the network. MISO collects congestion revenue in the day-ahead market based on the differences in the congestion component of the LMPs at locations where energy is produced and consumed. The resulting congestion revenue is paid to holders of FTRs, which are economic property rights to the transmission system.

A large share of the value of these rights is allocated to participants. The residual FTR capability is sold in the FTR markets with this revenue contributing to the recovery of the costs of the network. FTRs provide an instrument 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 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).

Figure 27 summarizes the day-ahead congestion by region (and between regions), as well as the balancing congestion incurred in real time and the FTR funding levels from 2016 to 2018.

**Figure 27: Day-Ahead and Balancing Congestion and FTR Funding**
2016–2018




*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 fell 5.7 percent to $700 million in 2018. The day-ahead congestion costs collected through the MISO markets were only half of the value of real-time congestion on the system. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network, as well as entitlements on the MISO system granted to SPP and PJM and other JOA parties that are not included in the day-ahead congestion settlement.

More than one quarter of all congestion during the winter occurred on January 17 and 18 because of emergency conditions that occurred. Day-ahead congestion on January 18 was much higher than real-time congestion costs because emergency actions lowered the real-time congestion. In the spring quarter, day-ahead congestion fell by 17 percent, largely because of lower gas prices.

Although natural gas prices rose by roughly 15 percent in the fall compared to 2017, better market-to-market coordination contributed to lower day-ahead congestion in the fall of 2018.

### *FTR Shortfalls*

Over- and underfunding of FTRs is caused by discrepancies in the modeling of transmission constraints and outages in the FTR auctions versus the day-ahead market. For example, if a day-ahead market constraint's limit decreases that was binding in the FTR market, a congestion shortfall will occur. In 2018, FTR obligations exceeded congestion revenues by $14.9 million – a shortfall of roughly one percent before auction residual collections.[25]

External constraints and low-voltage constraints near the edge of the MISO footprint 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 results in the failure to collect all of the congestion revenue necessary to satisfy all of the obligations for some of the FTRs. FTRs impacted by SPP constraints, for example, were underfunded by 37 percent in 2018.[26] In contrast, FTRs impacted by the transfer constraints between the South and Midwest regions tend to be over-funded because they can bind in both directions. This causes them not to be fully subscribed and to generate surpluses when binding in either direction.

The most significant causes for episodic underfunding continue to be planned and unplanned transmission outages - particularly forced and short-duration scheduled outages or derates that are not reflected in the FTR auctions. This can cause funding levels to vary substantially by local balancing areas ("LBA").[27] The FTR impacts related to transmission constraints in six LBAs was 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.

Underestimated loop flows also account for the some of the shortfalls because loop flows across the MISO system reduce the transmission capability MISO can utilize in the day-ahead and real-time markets. In 2018, these factors were more than offset by FTR surpluses produced on constraints with excess capability not sold in the FTR auctions.

25 Residual collections from the MPMA totaled $37.7 million for calendar year 2018. After accounting for this revenue, FTRs were funded at 101.4 percent.

26 Improvements to the GSF cutoff are discussed and recommended later in this Section.

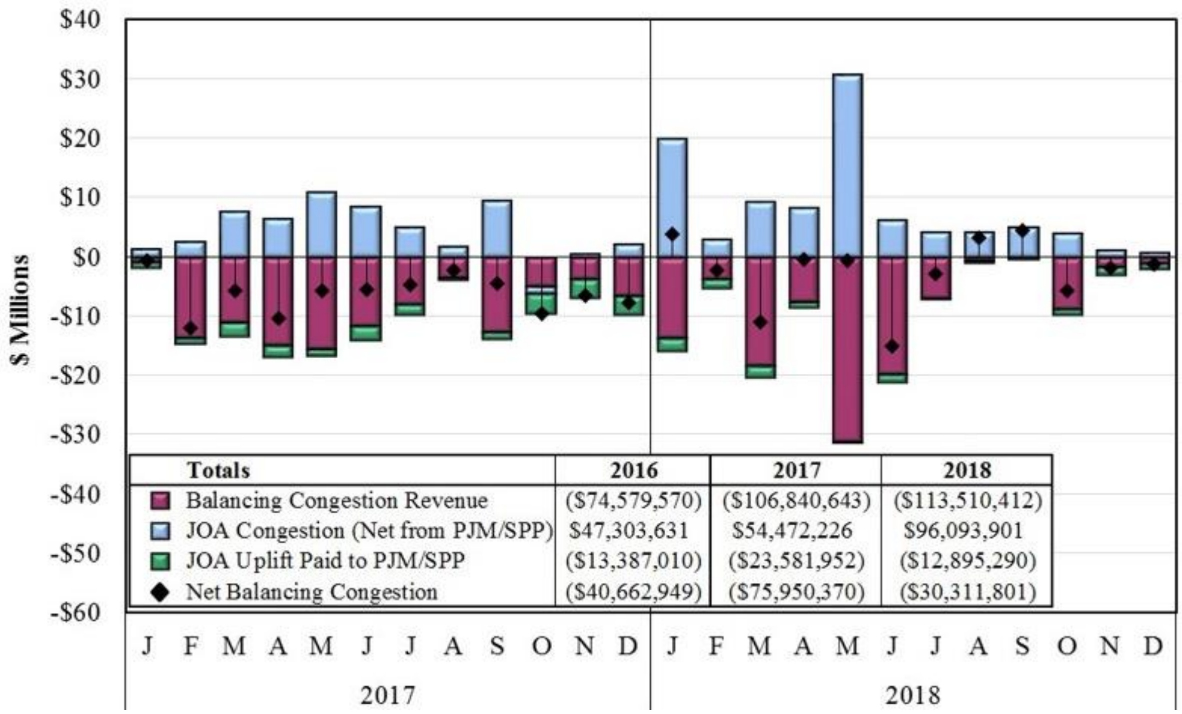
27 See Figure A88 in the Analytic Appendix.

### *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 flows that were scheduled in the day-ahead market 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 28 shows the monthly balancing congestion costs incurred by MISO over the past two years.

**Figure 28: Balancing Congestion Costs**
2016–2018




| Totals | 2016 | 2017 | 2018 |
|---|---|---|---|
| Balancing Congestion Revenue | ($74,579,570) | ($106,840,643) | ($113,510,412) |
| JOA Congestion (Net from PJM/SPP) | $47,303,631 | $54,472,226 | $96,093,901 |
| JOA Uplift Paid to PJM/SPP | ($13,387,010) | ($23,581,952) | ($12,895,290) |
| Net Balancing Congestion | ($40,662,949) | ($75,950,370) | ($30,311,801) |

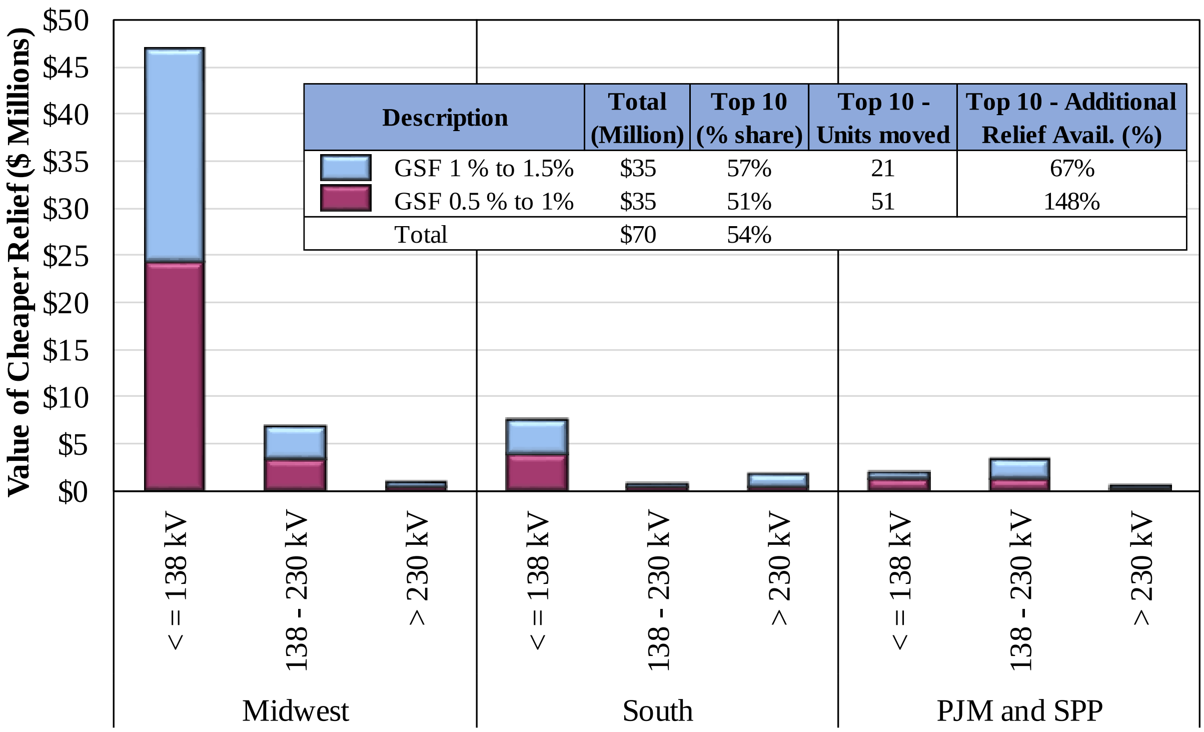
Net balancing congestion costs fell 60 percent in 2018 to just over $30 million, excluding JOA uplift of $12.9 million. JOA uplift payments are made to pay for market flows that exceed entitlements on coordinated market-to-market constraints. MISO had balancing congestion shortfalls in most months, but overall the levels were a considerably lower than last year.

### *Modifying GSF Cutoffs for Congestion Management*

In this year's report, we evaluate the economic benefits of modifying the GSF cutoff MISO uses in its market software. A generation shift factor ("GSF") indicates how changes in net injections at a given node will impact flows on the constraint. MISO employs a GSF cutoff of 1.5 percent so that electrically-distant generators will not be re-dispatched to manage congestion in order to reduce the complexity and solution time of its market software. While this is generally reasonable, it excludes valuable congestion relief on some constraints and can adversely affect reliability, increase M2M settlement costs, and lead to FTR shortfalls and surpluses. We evaluated the benefits of reducing the GSF cutoff down to 0.5 percent in 2018.

In Figure 29, 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.

**Figure 29: Value of Additional Available Relief**
2018




| Description | Total (Million) | Top 10 (% share) | Top 10 - Units moved | Top 10 - Additional Relief Avail. (%) |
|---|---|---|---|---|
| GSF 1 % to 1.5% | $35 | 57% | 21 | 67% |
| GSF 0.5 % to 1% | $35 | 51% | 51 | 148% |
| Total | $70 | 54% | | |

This analysis shows $70 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 small number of low-voltage constraints and M2M constraints. MISO could capture 54 percent of the benefits if they implemented a 0.5 percent GSF cutoff for just ten constraints. This is important because it would likely not be feasible to reduce the cutoff on all constraints. Hence, we recommend MISO modify its software to allow it to reduce the GSF cutoff on individual constraints.

### *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 reduces 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 on planned outages.

Participants tend to schedule planned outages in shoulder months, assuming that the opportunity costs of taking outages are lower because temperatures are mild and prices are relatively low. However, this is not always true. Multiple participants may schedule generation outages in a constrained area or transmission outages into the area without knowing what others are doing. Absent a reliability concern, MISO does not have the tariff authority to deny or postpone a planned outage, even when it could have substantial economic benefits. Figure 30 provides a high-level evaluation of how uncoordinated planned outages can affect congestion by showing the portion of the real-time congestion value incurred in 2017 and 2018 that occurred on internal constraints that were substantially affected (at least 10 percent of the constraints' flows) by two or more planned outages.

**Figure 30: Congestion Affected by Multiple Planned Generation Outages**
2017–2018

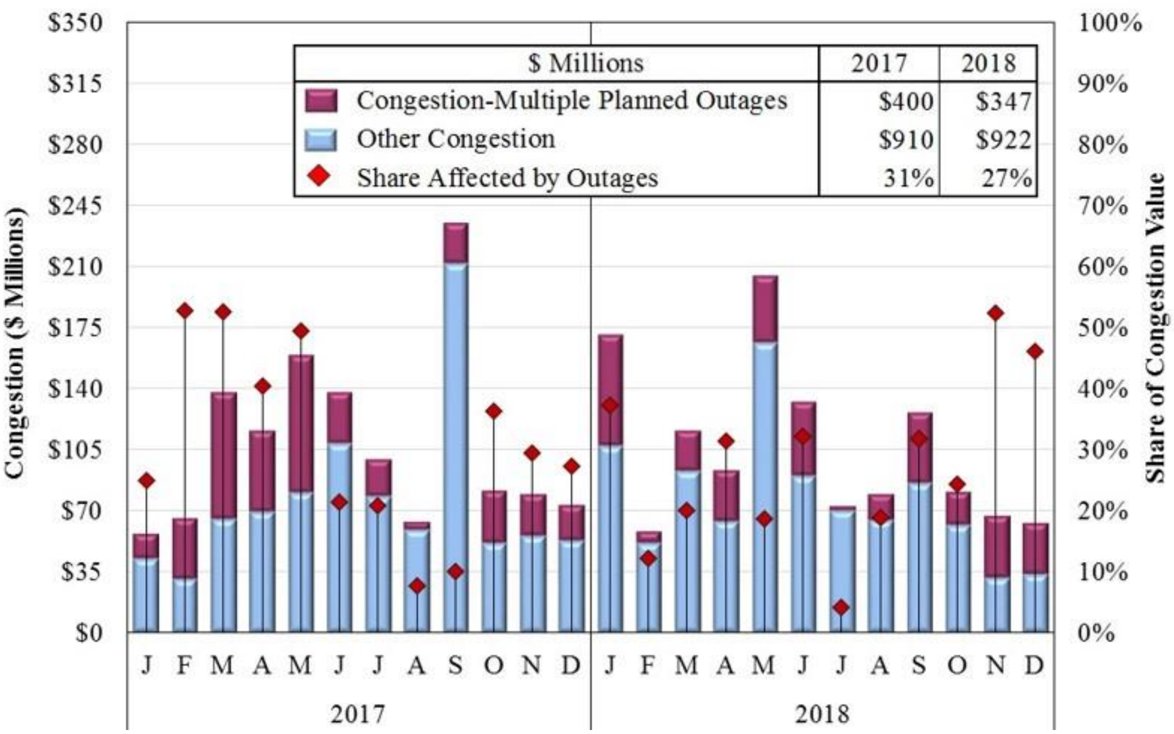



Figure 30 shows that 27 percent of the total real-time congestion on MISO's internal constraints in 2018 – $347 million – was attributable to multiple planned generation outages. In most months, planned outages caused significant congestion, including about half of all congestion in November and December combined. Figure 30 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.

Given how costly outages can be, we continue to recommend that MISO seek expanded authority to coordinate planned generation and transmission outages in order to reduce unnecessary economic costs.

## C. FTR Market Performance

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

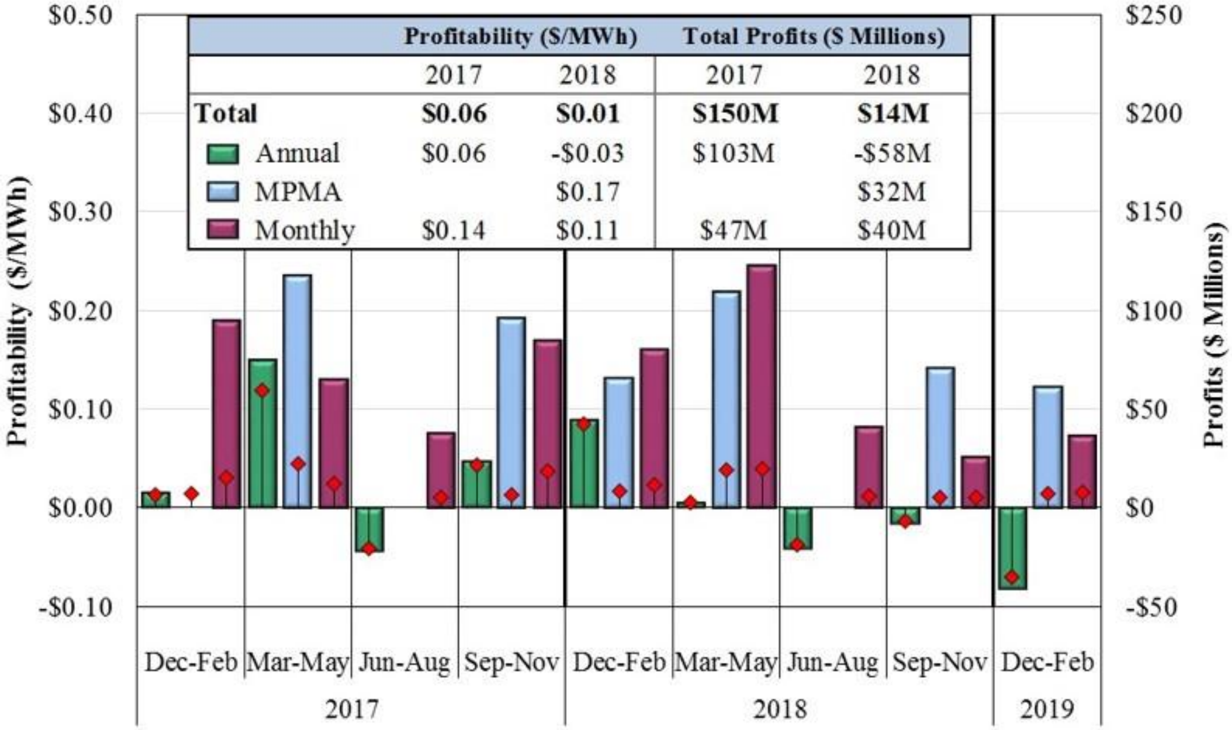
- An annual auction from June to May that includes seasonal and peak/off-peak resolution of bids, offers, and awards; and
- A Multi-Period Monthly Auction (MPMA) that yields monthly and seasonal peak/off-peak awards. The MPMA facilitates FTR trading for future periods in the planning year.

### *FTR Market Profitability*

Figure 31 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 31 shows that FTRs issued through the annual FTR auction were profitable overall as losses in the third and fourth quarters of 2018 were offset by profits in the rest of the year. In prior years, FTR losses were partly the result of market participants "self-scheduling" ARRs (converting the ARRs to FTRs), which is equivalent to bidding to buy the FTR at any price or refusing to sell at any price. However, in the 2017-2018 auction year, large day-ahead congestion overwhelmed the impacts of that behavior, particularly early in 2018.

**Figure 31: FTR Profits and Profitability**
2017–2018




*FTR Profitability in the MPMA.* Figure 31 shows that the FTRs purchased in the MPMA and prompt month have been profitable, although the profitability of FTRs purchased in the MPMA fell 75 percent over last year. In general, these markets tend to produce prices that are more in line with anticipated congestion than the annual auction, in part because they occur much closer to the operating timeframe when better information is available to forecast congestion.

### *Multi-Period Monthly FTR Auction*

In the MPMA FTR auction, MISO generally makes additional transmission capability available for sale and sometimes buys back capability on oversold transmission paths. MISO buys back capability by selling "counter-flow" FTRs, which are negatively priced FTRs on oversold paths. In essence, MISO is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on a constraint.[28]

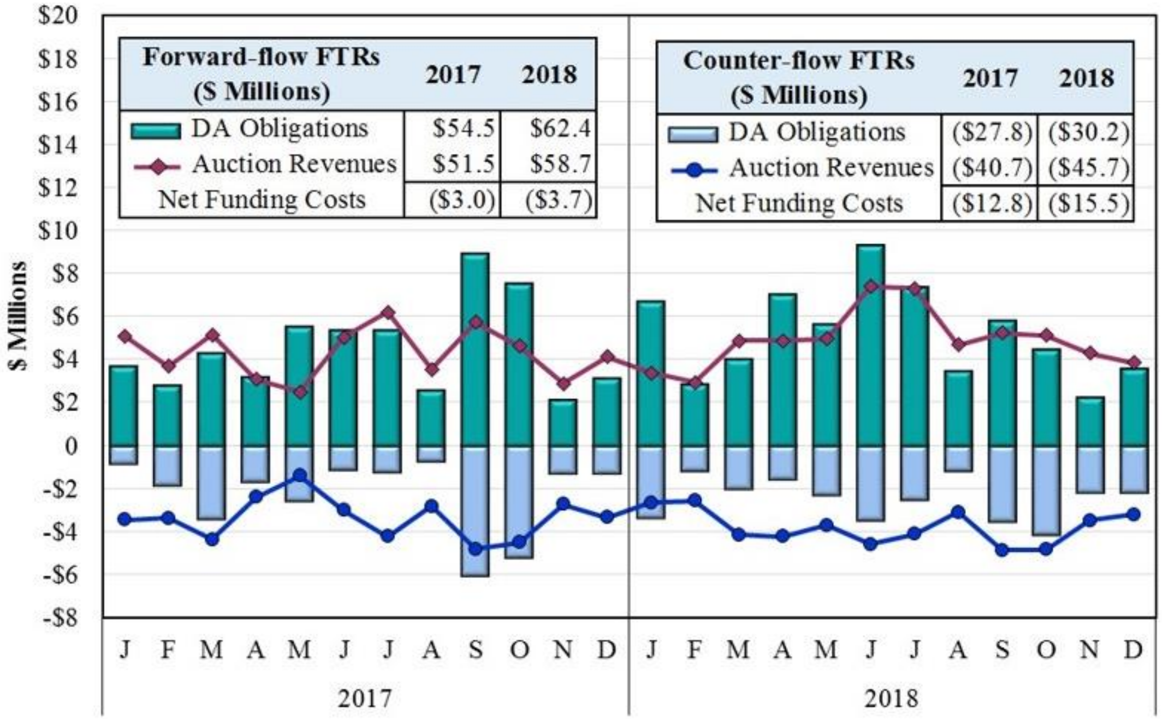
MISO is restricted in its ability to sell counter-flow FTRs because it is prohibited from clearing the MPMA with a negative financial residual. That means that MISO can only fund the purchase of counter-flow FTRs with net revenues from same auction. This artificial restriction limits MISO's ability to resolve feasibility issues through the MPMA. In other words, when MISO

28 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 so the FTR obligation in the day-ahead market would be 200 MW.

knows a path is oversold, MISO often cannot reduce the FTR obligations on the path by selling counter-flow FTRs. This is not always inefficient because it may be more costly to sell counter-flow FTRs than it is to simply incur the FTR shortfall in the day-ahead market.

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure 32 compares the auction revenues from the MPMA prompt month (the first full month after the date of 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 32: Prompt-Month MPMA FTR Profitability**
2017–2018




This figure shows that MISO sold forward-flow FTRs at roughly 6 percent less than their ultimate value in 2018, comparable to the results in 2017. However, MISO paid participants 51 percent more to accept counter-flow FTRs than the value of these obligations in 2018, up slightly from 46 percent in 2017. While the negative auction residual restriction artificially limits MISO's ability to sell counter-flow FTRs, this limitation benefited MISO's customers in 2018 based on the pattern of inflated prices for counter-flow FTRs shown in the figure.

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 or the sale of counter-flow FTRs at unreasonably high prices.

## D. Improving the Utilization of the Transmission System

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.[29] Therefore, if transmission owners develop and submit temperature-adjusted transmission ratings, they would allow MISO to operate to higher transmission limits and achieve substantial production costs savings. Most transmission owners do not provide temperature-adjusted ratings.

Additionally, ratings for contingency constraints should correspond to the short-term emergency rating level (i.e., the flow level that the monitored facility could reliably accommodate in 2-4 hours if the contingency occurs). Most transmission owners provide MISO with both normal and emergency limits as called for under the Transmission Owner's Agreement.[30] However, we have identified some transmission owners that provide only normal ratings for most facilities.

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. 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 rates 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. This analysis is described in detail in Section VI.E of the Analytic Appendix and summarized in Table 7.

29 Temperature is one common dynamic factor. In some regions, ratings are more dependent on other factors, such as ambient wind speed and humidity. Our analysis evaluates only ambient temperature impacts.

30 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.

**Table 7: Benefits of Temperature-Adjusted and Emergency Ratings**
2017–2018

| | | Savings ($ Millions) | | | | |
|---|---|---|---|---|---|---|
| | | Temp. Adj. Ratings | Emergency Ratings | Total | # of Facilities for 2/3 Savings | Share of Congestion |
| **Total Estimated Benefits** | | | | | | |
| **2018** | Midwest | $70.9 | $50.92 | $121.8 | 22 | 12.4% |
| | South | $7.0 | $16.86 | $23.9 | 2 | 6.7% |
| | Total | **$77.9** | **$67.8** | **$145.7** | **24** | **10.9%** |
| **2017** | Midwest | $83.8 | $38.83 | $122.7 | 20 | 11.7% |
| | South | $10.0 | $23.07 | $33.1 | 3 | 8.9% |
| | Total | **$93.9** | **$61.9** | **$155.8** | **23** | **10.9%** |

The results across the two years show consistent benefits equal to 11 percent of the real-time congestion value, including $80 to $95 million per year for temperature-adjusting the ratings and $60 to $70 million per year for using emergency ratings. The benefits of temperature adjustments accrue primarily outside the summer months when static ratings are most understated. In July and August, the average increase in transmission ratings was only 4 percent, while the average increase was almost 10 percent in the other months. The benefits of using emergency ratings are more evenly distributed, as one would expect. Section VI.E shows how these estimated benefits in 2018 are distributed in the areas served by transmission owners.

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. Further expansion of the program to other transmission operators would generate considerable congestion management savings throughout MISO. Only one other transmission owner currently utilizes temperature-adjusted ratings on many 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 8. These benefits are estimated by multiplying the rating increases (from the static rating level) by the prevailing shadow prices. This methodology is a conservative estimate of savings, given that the shadow price would increase if the market was controlling to a lower, non-adjusted rating.

From 2017 to 2018, the actual savings totaled more than $50 million – almost 8 percent of the congestion on the transmission facilities. Over $37 million of the savings were on Entergy's transmission facilities in the South – 9 percent of congestion on those facilities. These savings estimates are conservative because the costs of managing to a lower limit would increase.

**Table 8: Estimated Achieved Savings by Two Transmission Owners**
2017–2018

| | Savings ($ Millions) | Share of Congestion |
|---|---|---|
| Midwest | $14.0 | 5.4% |
| South | $37.3 | 9.0% |
| **Total** | **$51.3** | **7.6%** |

We believe that at least one of the reasons why most transmission owners do not provide temperature-adjusted ratings is that there is little economic incentive to do so. One means to address this issue is to provide an economic incentive to the TOs that is related to the benefits of the additional transmission capability. This is reasonable because using higher transmission limits would reduce congestion costs and benefit the loads. Since the FTR market limits flows to the static seasonal ratings, use of temperature-adjusted day-ahead ratings will result in day-ahead congestion surpluses. These surpluses are equal to the increase in the limit times the shadow price of the constraint. A portion of this surplus could be used to compensate the TOs. There could also be opportunities for TOs to determine a TCDC price above the static rating that would align their expectation of incremental risk with surplus compensation.

In conclusion, we continue to recommend that MISO work with TOs to gather and use temperature-adjusted, short-term emergency ratings, which could include creating economic incentives for them to provide such ratings. Additional savings could be achieved by using predictive ratings in the day-ahead market based on forecasted temperatures and wind speeds.

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

MISO’s market-to-market 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 market-to-market 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 provides relief and reduces its “market flow” below its FFE, the monitoring RTO will compensate it for this relief by paying it the marginal value of the relief. Conversely, if the non-monitoring RTO’s market flow exceeds its FFE, the non-monitoring RTO will pay the monitoring RTO for the excess flow times the marginal costs incurred by the monitoring RTO.

### *Summary of Market-to-Market Settlements*

Congestion on MISO market-to-market constraints rose 9 percent to total $508 million in 2018. Congestion on external market-to-market constraints (those monitored by PJM and SPP) fell 26 percent to $51 million in 2018. Settlement results on market-to-market constraints included:

- Net payments totaling $94 million flowed from PJM to MISO in 2018, an increase of 78 percent from 2017. Net payments generally flow from PJM because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system.
  - The increase in net payments was partly due to improvements in market-to-market coordination between MISO and PJM that are described later in this section.
  - 53 percent of PJM's payments to MISO occurred in January and May when a pseudo-tied unit and wind units in PJM had large impacts on MISO constraints.
- Conversely, MISO's market-to-market settlements with SPP in 2018 resulted in net payments of $16 million from MISO to SPP.

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

We evaluate the effectiveness of the market-to-market process by tracking the convergence of the shadow prices of market-to-market constraints in each market. When the process is working well, the non-monitoring RTO will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the marginal cost of the monitoring RTO's relief. Our analysis shows that for the most frequently binding market-to-market constraints, the market-to-market process generally contributes to shadow price convergence over time and substantially lowers the monitoring RTO's shadow price when the market-to-market process is initiated.

While the market-to-market 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 market-to-market constraints;
- Delays in testing constraints after they start binding to determine whether they should be classified as market-to-market; and
- Delays in activating market-to-market constraints for coordination after they have been classified as market-to-market.

Each of these issues is significant because when a market-to-market constraint is not identified or activated, it raises the following concerns:

- *Efficiency concerns*. The savings of coordinating with the non-monitoring RTO to relieve the constraint are not achieved and congestion costs are increased.
- *Equity concerns*. The non-monitoring RTO may vastly exceed its firm flow entitlements on the constraint with no compensation to the monitoring RTO.

We developed a series of screens to identify constraints that should have been coordinated but were not because of the issues listed above. These screens identified 36 non-market-to-market constraints that should have been coordinated as market-to-market with either PJM or SPP. Table 9 shows the total congestion on these constraints, subdivided by three reasons why they were not coordinated. 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 9: Real-Time Congestion on Constraints Affected by Market-to-Market Issues**
2018

| Item Description | PJM ($ Millions) | | SPP ($ Millions) | | Total ($ Millions) | |
|---|---|---|---|---|---|---|
| | 2017 | 2018 | 2017 | 2018 | 2017 | 2018 |
| **Never classified as M2M** | $85 | $5 | $109 | $15 | $194 | $21 |
| **M2M Testing Delay** | $19 | $22 | $11 | $8 | $31 | $29 |
| **M2M Activation Delay** | $6 | $11 | $12 | $7 | $18 | $18 |
| **Total** | $110 | $38 | $133 | $30 | $243 | $68 |

This table shows that the largest congestion occurred on constraints that were never classified as market-to-market constraints even though they would likely pass the market-to-market tests. In almost all cases, this occurred because MISO did not request market-to-market tests. This prompted a recommendation in the 2016 SOM (2016-2) for MISO to improve market-to-market identification and testing procedures. In December 2017, MISO implemented a tool to improve these procedures, which resulted in significant improvements in the process.

A key insight of our evaluation is that some of the costliest market-to-market constraints are more efficient for the non-monitoring RTO to assume the monitoring responsibility. This occurs when the non-monitoring RTO has the vast majority of the effective relief capability (and likely the most market flows). To facilitate this process, MISO and SPP began using new software in 2017 that enables the RTOs to transfer flowgate monitoring responsibility, but it has rarely been used. PJM has not yet agreed to use this software and has continued to only allow such transfers in limited circumstances. Hence, we recommend that MISO continue working with SPP and PJM to improve the procedures for a monitoring RTO to transfer the monitoring responsibility for a market-to-market constraint to the non-monitoring RTO when appropriate.

Finally, convergence is much less reliable in the day-ahead market. MISO and PJM implemented our recommendation to coordinate FFE levels in the day-ahead market in late January 2016, but do not actively utilize this process, so it has not had substantial effects. SPP has not agreed to implement a similar day-ahead coordination procedure.

## F. Effects of Pseudo-Tying MISO Generators

Increasing quantities of MISO capacity have been exported to PJM. PJM requires external capacity to be pseudo-tied to PJM. We have been raising concerns about the number of pseudo-tied resources because allowing PJM to take dispatch control of large numbers MISO generators:

- Causes forward flows over a large number of MISO transmission facilities that are difficult to manage; and

- Transfers control of generators that relieve other MISO constraints so that MISO will no longer have access to them to manage congestion on these constraints.

The first issue can be partially addressed to the extent that these constraints will be defined as market-to-market constraints and, therefore, coordinated with PJM. However, this coordination is not as effective as dispatch control, and many constraints will not be coordinated. Additionally, the increasing number of market-to-market constraints that must be coordinated only because of the pseudo-tied resources' places substantial strain on the market-to-market process and reduces the effectiveness of the coordination. Since 2016, we have found:

- 59 new market-to-market constraints in MISO have been defined because of the MISO units that have been pseudo-tied to PJM.
- Congestion costs on these constraints was $25 million in 2018, significantly higher than the congestion costs they exhibited prior to the pseudo-ties.

This congestion amount is inefficiently large because it is not possible for the market-to-market process to result in an efficient commitment and dispatch of these resources. In other words, because pseudo-tied units located on MISO's transmission system are now under the dispatch control of PJM, MISO's ability to efficiently manage congestion on the affected portions of the MISO network is undermined. This is a serious issue, not only because of the increased congestion on these constraints, but also because the pseudo-tied units affect many other MISO constraints that are not market-to-market constraints because they do not satisfy the criteria.[31]

Hence, we continue to be very concerned about the inefficiencies and impacts on reliability caused by large numbers of generators interconnected with MISO pseudo-tying to PJM. While pseudo-tying between balancing area operators is not new to the wholesale industry, it has never been implemented at this magnitude, nor would it be without the PJM requirement.

While inefficiencies of pseudo-ties are clear, it is not clear what benefits PJM is achieving that cannot be achieved by better alternatives. We have and continue to recommend that MISO and PJM develop procedures for firm capacity delivery as a more efficient and reliable alternative to pseudo-tying resources to PJM. To facilitate this solution, we filed a Section 206 complaint against PJM's tariff to eliminate its current requirement that all external resources be pseudo-tied to PJM.[32] FERC has yet to address this complaint.

## G. Congestion on Other External Constraints

In addition to congestion from internal and external market-to-market constraints, congestion in MISO can occur on external constraints when other system operators call for a TLR, which causes MISO to activate the external constraint in MISO's real-time market. This results in

31 MISO also loses the ability to economically commit/decommit pseudo-tied units to manage congestion.
32 See Complaint filed in Docket No. EL17-62, April 5, 2017.

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 even though most 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 TVA that would allow TVA and MISO to coordinate the relief on each other's transmission system more efficiently. To quantify the potential value of such a JOA, Table 10 shows the total congestion and potential savings in periods when TVA had lower-cost relief available than MISO on MISO's constraints (first row) and TVA's constraints (second row).

**Table 10: Economic Relief from TVA Generators in 2018**

| Status | Total Congestion Value ($ Millions) | Re-dispatch Savings ($ Millions) |
|---|---|---|
| **MISO Constraints** | $272.5 M | $26.8 M |
| **TVA (TLR) Constraints binding in MISO** | $3.3 M | $2.0 M |
| **Total** | $275.8 M | $28.8 M |

This analysis shows that coordination would lower costs on both systems, make MISO's relief obligations more equitable, and reduce price distortions caused by TVA's TLRs. To illustrate the costs of TLRs, we examine a TLR called by TVA on September 22, 2017 on the Volunteer-Phipps Bend (VPB) line, which caused:

- MISO to activate the constraint in its real-time dispatch, which led to widespread redispatch changes; and
- Higher average prices throughout the Midwest region by as much as $110 per MWh.

TLRs are never optimal, but this TLR was called as a proxy to acquire relief on a low voltage constraint that would not qualify for TLR. The effects on MISO were grossly inefficient because most of the LMP and dispatch effects were at locations that had no material effect on the underlying 161kV constraint and caused MISO to violate a number of its own constraints. Further, neither VPB nor the lower-voltage constraint were close to their limit during the event.

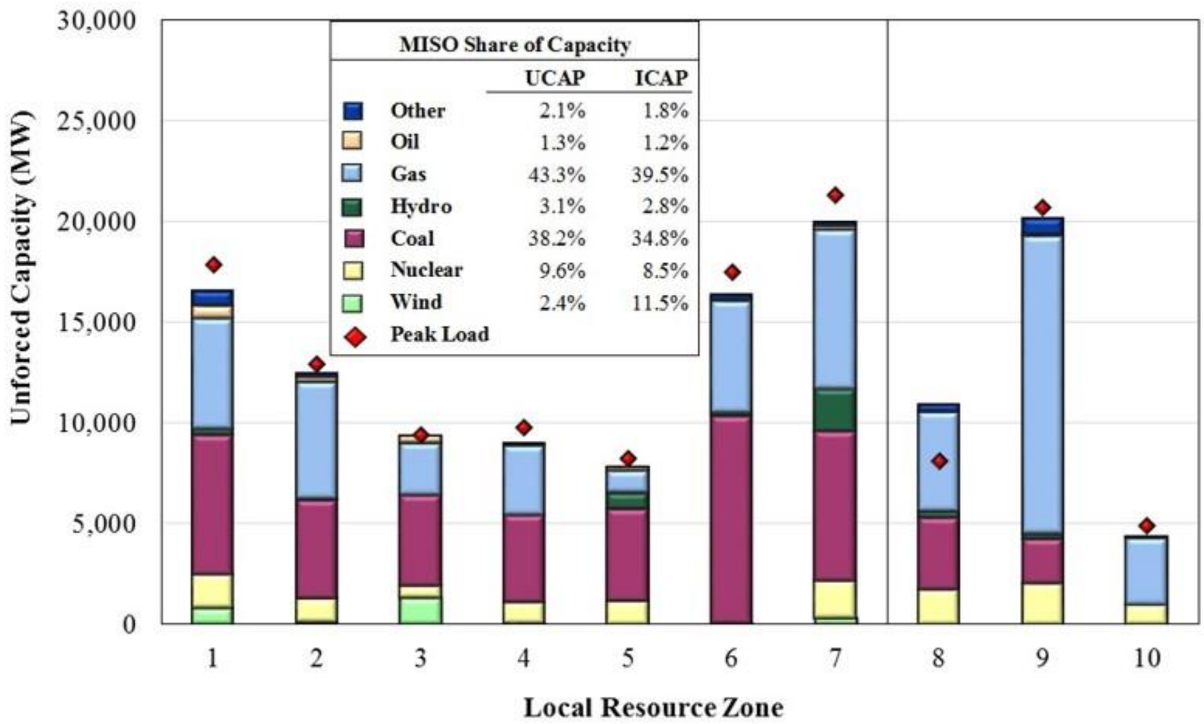
# VII. Resource Adequacy

This section evaluates the adequacy of the supply in MISO for the upcoming summer and discusses improvements to MISO markets that would promote efficient investment and retirement decisions to satisfy MISO's long-term resource adequacy needs.

## A. Regional Generating Capacity

The next two figures show the distribution of existing generating capacity by Local Resource Zone ("LRZ") and fuel type. Figure 33 shows the distribution of Unforced Capacity (UCAP) at the end of 2018 by zone and fuel type, along with the 2018 coincident peak load in each LRZ.[33] UCAP values account for forced outages and intermittency; therefore, UCAP values for wind units are significantly lower than Installed Capacity (ICAP) values, as shown in the inset table. Hence, although wind is over eleven percent of MISO's ICAP, it is two percent of the UCAP.

**Figure 33: Distribution of Existing Generating Capacity**
By Fuel Type and Zone, December 2018



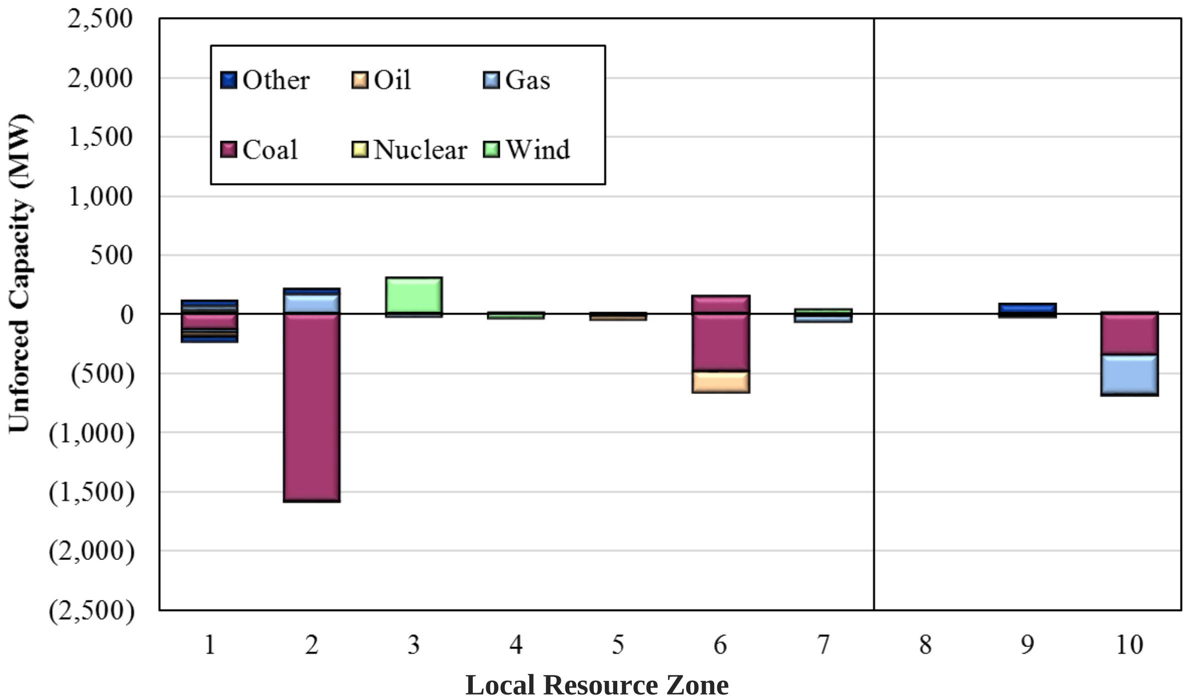

This figure shows that gas-fired resources account for a larger share of MISO's capacity than any other capacity type, including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from the South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

33 UCAP was based on data from the MISO PRA for the 2018/2019 Planning Year and excludes LMR capacity.

## B. Changes in Capacity Levels

Capacity levels have been falling in MISO because of accelerating retirements and capacity exports to PJM. Figure 34 shows the capacity additions (positive values) and losses during 2018.

**Figure 34: Distribution of Additions and Retirements of Generating Capacity**
By Fuel Type and Zone, 2018




### *Capacity Losses*

In 2018, 4 GW of resources retired in MISO. Environmental regulations and sustained low gas and associated energy prices led to continuing coal-fired unit retirements, which totaled more than 2.5 GW in 2018. These retirements produced a net unforced capacity loss of 3.4 GW. We expect this to continue because, among other things, of the weak economic signals provided by MISO's current capacity market.

### *New Additions*

Most of the 1.9 GW of new capacity additions in MISO were wind resources that provide less reliability value than conventional resources. Additional investment in wind resources is likely to occur in the coming years as Multi-Value Projects (MVP) are completed, which include 17 current and past transmission projects estimated to cost more than $6.5 billion in aggregate. Thirteen of these projects are completed, three are expected to be completed in 2019, and one project is pending.

### *Planning Reserve Margins and Summer 2019 Readiness*

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2019. Assumptions made about the supply that will be available during the summer peak and the load that will occur can substantially change the estimated planning reserve margins. Therefore, we present a base case and four additional scenarios that more realistically represent MISO's summer peak reliability margin. Table 11 summarizes these scenarios.

**Table 11: Summer 2019 Planning Reserve Margins**

| | | Alternative IMM Scenarios | | | |
|---|---|---|---|---|---|
| | | | | High Temperature Cases | |
| | Base Scenario | Realistic Scenario | Realistic <=2HR* | Realistic Scenario | Realistic <=2HR* |
| **Load** | | | | | |
| Base Case | 124,744 | 124,744 | 124,744 | 124,744 | 124,744 |
| High Load Increase | - | - | - | 6,554 | 6,554 |
| **Total Load (MW)** | 124,744 | 124,744 | 124,744 | 131,298 | 131,298 |
| **Generation** | | | | | |
| Internal Generation Excluding Exports | 134,856 | 134,856 | 134,422 | 134,856 | 134,422 |
| BTM Generation | 4,588 | 4,588 | 2,845 | 4,588 | 2,845 |
| Unforced Outages** | (338) | (10,486) | (10,486) | (11,833) | (11,833) |
| Adjustment due to Transfer Limit | (1,220) | - | - | - | - |
| **Total Generation (MW)** | 137,885 | 128,958 | 126,781 | 127,610 | 125,434 |
| **Imports and Demand Response*** ** | | | | | |
| Demand Response | 7,684 | 7,684 | 5,093 | 7,684 | 5,093 |
| Capacity Imports | 3,272 | 3,272 | 3,272 | 3,272 | 3,272 |
| **Margin (MW)** | 24,097 | 15,170 | 10,402 | 7,269 | 2,501 |
| **Margin (%)** | **19.3%** | **12.2%** | **8.3%** | **5.8%** | **2.0%** |
| **Effects of Non-Firm Imports** | | | | | |
| Summer Peak Net Imports | 2,161 | 2,161 | 2,161 | 2,161 | 2,161 |
| **Expected Margin (MW)** | 26,258 | 17,330 | 12,563 | 9,429 | 4,662 |
| **Expected Margin (%)** | **21.0%** | **13.9%** | **10.1%** | **7.6%** | **3.7%** |

* Assumes 100% response from resources available within 2 hours.
** Base scenario shows approved planned outages for 19/20 summer.
Alternatives use historical average unforced unit unavailability during July and August peak hours.
*** Cleared amounts for the 2019/2020 planning year.

*Base Case*. We have worked closely with MISO to ensure that our Base Case planning reserve level is consistent with MISO's assumptions in its *2019 Summer Resource Assessment*, including the 1,500 MW transfer limit assumption[34] between MISO South and Midwest. This case also assumes that: a) MISO will be able to access all demand response resources in a given emergency situation, and that b) the summer planned outages will be limited to those scheduled and approved by April 1, 2019. The planning reserve margin in this case is more than 19 percent, which substantially exceeds the Planning Reserve Margin Requirement (PRMR) of 16.8 percent.

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

*Realistic Case.* 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, and that
- Planned and unreported outages and derates will be consistent with the average of the previous two years' summer peak months during on-peak hours.

In this realistic scenario, the planning reserve margin falls to 12.2 percent, well below the 16.8 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 when shortages occur to resolve the shortage. Hence, the table includes additional imports that correspond to an average amount of additional imports during summer peak conditions. This is conservative because the import levels would likely rise to much higher levels in response to shortage pricing in MISO. Nonetheless, the table shows that including these non-firm imports would raise the margin to almost 14 percent, which is still less than the capacity requirement.

*Realistic Scenario < 2 Hour Emergency Resources.* Unfortunately, even the realistic scenario is likely to be excessively optimistic because it assumes all resources will be available when an emergency occurs. This has not generally been the case because MISO has recognized and declared emergencies between 10 minutes and 4 hours in advance of the emergency, which is not a surprise because they are often precipitated by unforeseen outages and other contingencies. Since a large quantity of emergency resources have much longer notification times (often up to 12 hours), we show this scenario that assumes only emergency resources that can start in two hours or less will be accessible. In this scenario, the planning reserve margin is only 8.3 percent, which is extremely low. Like the prior scenario, this relatively low margin does not reflect MISO's ability to access additional imports on a non-firm basis. Including typical peak levels of non-firm imports raises the planning reserve margin to 10.1 percent.

*High Temperature Cases*: We include two additional cases that modify the Realistic Scenario and Realistic Scenario < 2 Hour cases 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, while outlet water temperature or other environmental restrictions cause certain resources to be derated.[35] On the load side, we assume MISO's "90/10" forecast case (should only occur one year in ten).

35 These high-temperature derates are highly variable, so the value we assume is an average of what was observed on extreme peak days in 2006 and 2012. In its *2019 Summer Assessment*, MISO shows a high-load scenario, but we believe it likely understates the derates that may occur under high-temperature conditions.

The high-temperature cases using the realistic scenario and realistic plus limited emergency-only capacity show much lower margins—as low as 2 percent. This is significant because this margin must provide MISO's operating reserves (2,400 MW) and includes no assumed forced outages, which generally range from five to eight percent (but may be much higher because of correlated factors such as extreme temperatures). Non-firm imports may increase the margin to 3.7 percent, but this is still too low to accommodate typical levels of forced outages.

Overall, these results indicate that the system's resources are likely adequate for summer 2018 but may run short if the peak demand conditions are substantially hotter than normal. Going forward, planning reserve margins will likely decrease as fossil resources retire and are replaced by renewable resources, and suppliers continue to export capacity to PJM. Additionally, we are concerned that an increasing amount of the capacity reserve margin is being provided by LMRs that are accessible only after MISO declares an emergency. Therefore, it remains important for the capacity market to provide the efficient economic signals to maintain an adequate resource base. These issues are discussed in the following three subsections.

## C. Long-Term Economic Signals

While price signals play an essential role in coordinated commitment and dispatch of units in the short term, they also provide long-term economic signals that govern investment and retirement decisions for generators and transmission. This section evaluates MISO's long-term economic signals by measuring the net revenue a new generating unit would have earned in 2018.

Net revenue is the revenue a new unit would earn above its variable production costs if it ran when it was economic to run. A well-designed market should produce net revenue sufficient to support new investment when existing resources are not adequate to meet the system's needs. Figure 35 and Figure 36 show estimated net revenues for a new combustion turbine ("CT") and combined-cycle ("CC") generator for the prior three years in the Midwest and South regions. For comparison, the figures also show the annual net revenue that would be needed for these new 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 their 2017/2018 and 2018/2019 Planning Resource Auctions.

Changes in the net revenues were mixed in 2018. Net revenues were not sufficient to motivate investment in a CT or a CC in any location, despite the increase in net revenues for CCs that resulted from higher gas prices. The relatively low net revenues are consistent with expectations because of infrequent shortages, the prevailing capacity surplus, and capacity market design issues. Lower capacity auction clearing prices in the 2018-2019 PRA contributed to lower estimated net revenues for combustion turbines throughout most of the footprint. Estimated CC net revenues in Louisiana were the closest to CONE in 2018 and, in summer 2019, a new 980 MW CC unit is scheduled to begin operations.

**Figure 35: Net Revenue Analysis**
Midwest Region, 2016–2018

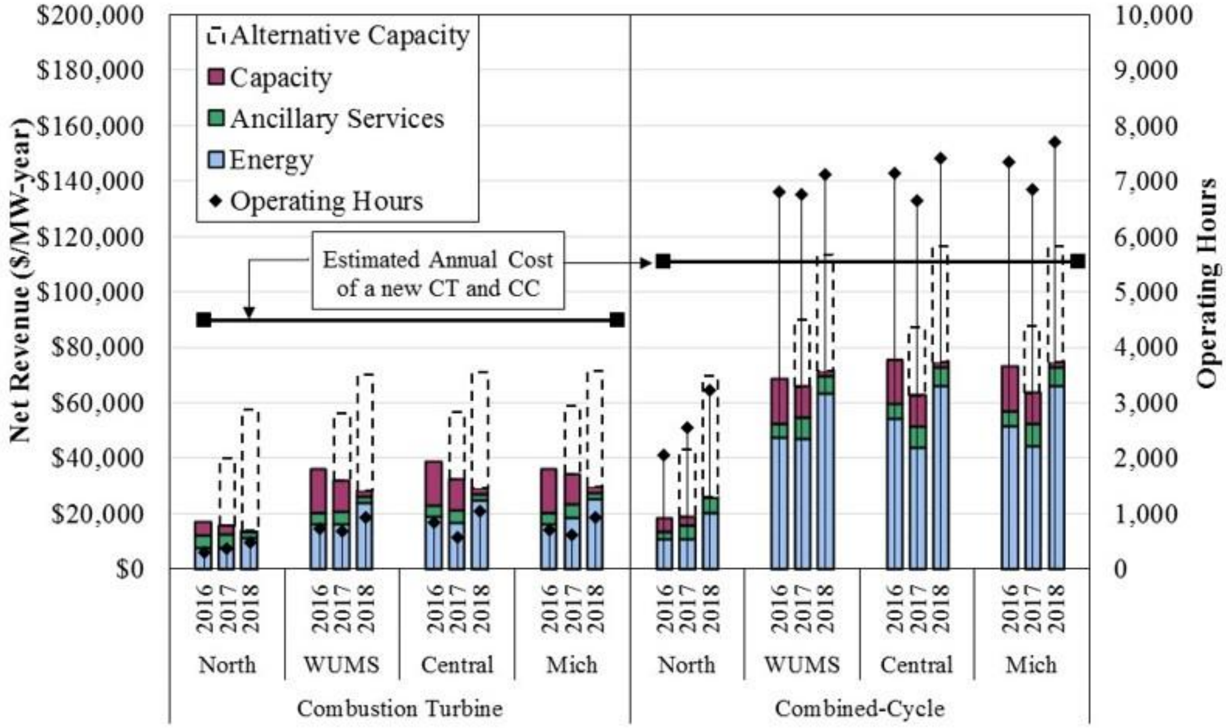
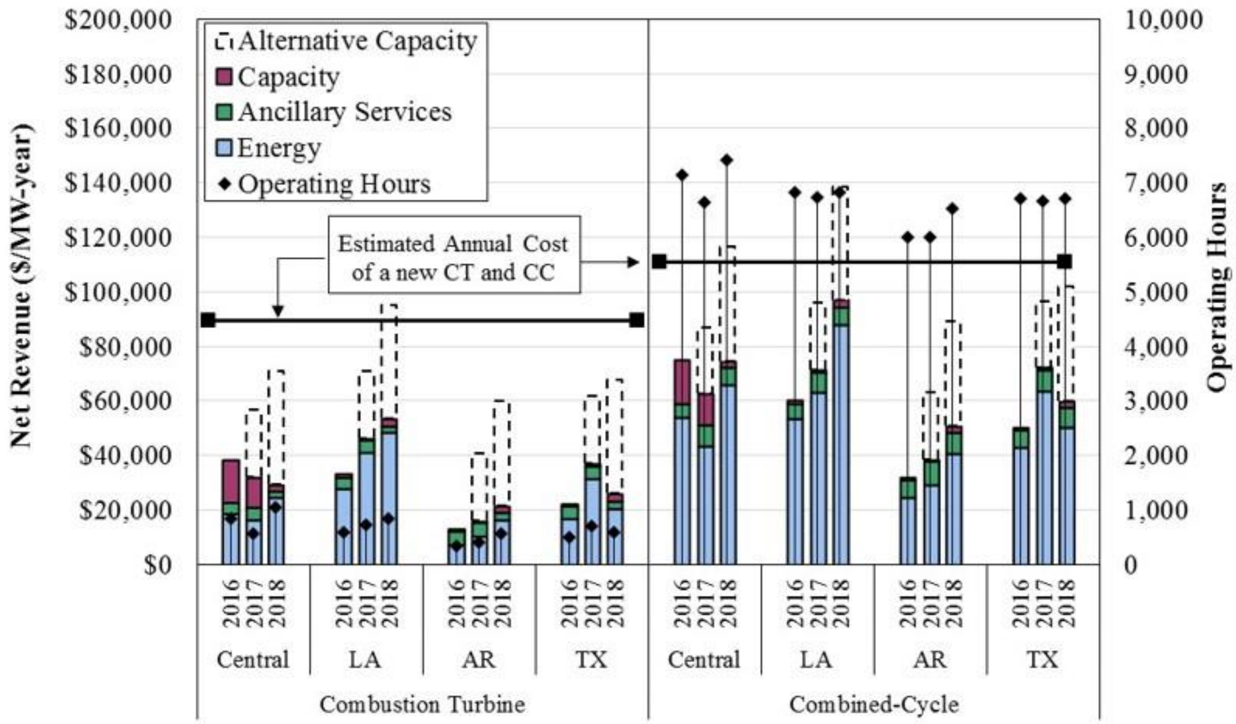



**Figure 36: Net Revenue Analysis**
South Region, 2016–2018




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

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 annual 2017/2018 and 2018/2019 Planning Reserve Auctions, the annual net revenues would have increased year over year for both resource types in all regions. This would have made CC's profitable to build in almost all locations.

The lack of the sloped demand curve raises particularly timely concerns; MISO's capacity surplus is dissipating as resources are facing 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 next section includes a discussion of these capacity market design and performance issues and recommendations.

## D. Attachment Y and SSR Status Designations

Attachment Y to the MISO Tariff requires suppliers seeking to retire or suspend a unit to notify MISO at least 26 weeks in advance. Based on a reliability study, MISO may then designate a resource as a System Support Resource (SSR). 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. The SSR agreement provides for compensation to the market participant during this period of delayed retirement or suspension. SSR status has been granted very infrequently. An SSR agreement was executed on April 1, 2018 for one unit in MISO South for a period of 12 months that expired on May 1, 2019.

As retirements accelerate, it is very important that the capacity market, the Attachment Y, and SSR processes are well aligned to allow the market to facilitate reasonable retirement decisions and capacity market outcomes. These issues are discussed in the following subsection.

## E. Capacity Market Results

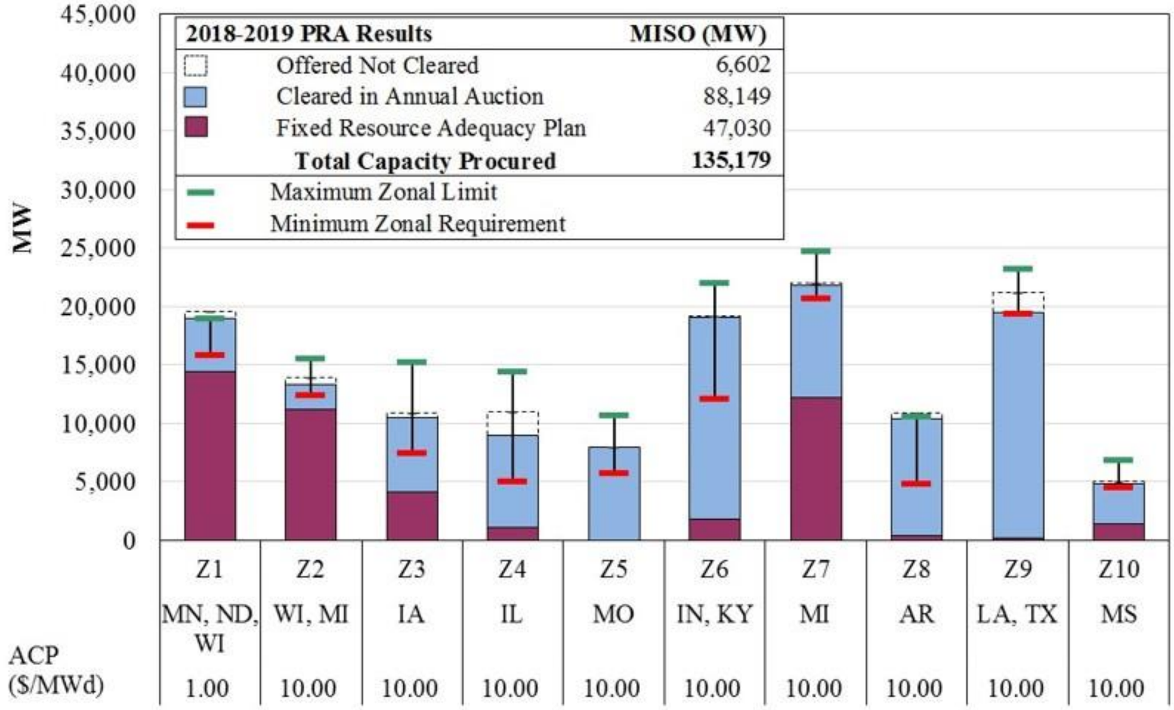
In wholesale electricity markets, the purpose of capacity markets is to facilitate long-term resource decisions to satisfy the systems' planning requirements. RTOs utilize capacity markets to efficiently satisfy the planning requirements in conjunction with their energy and ancillary services markets. The economic signals provided by these markets together inform long-term decisions, including decisions to build new units, 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 revenues that, in addition to energy and ancillary services market revenues, should signal when new resources are needed.

### *PRA Results for the 2018-2019 Planning Year*

Figure 37 shows the outcome of the PRA held in April 2018 for the 2018-2019 Planning Year. The figure shows the minimum and maximum amount of capacity that can be purchased in the red and green lines and the total amount of capacity offered (top of ghost bars), 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, which is equal to the local resource requirement minus the maximum level of capacity imports. The maximum amount is equal to the obligation plus the maximum level of capacity exports.

**Figure 37: Planning Resource Auctions**
2018–2019 Planning Year




*Prices.* Zone 1 was export-constrained and cleared at $1 per MW-day, while the clearing price in all other zones was $10 per MW-day. These prices are extremely low and provide suppliers with less than five 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 next subsection.

### *Qualifications and Accreditation of Supply in the PRA*

We have become increasingly concerned that MISO's rules: a) allow unavailable resources to satisfy its capacity requirements, and b) does not procure capacity for all of its firm load. Hence, we recommend several improvements to MISO's Planning Resource Auction that would result in better price signals for the value of capacity in MISO. In this subsection, we evaluate the impact that addressing these issues would have had on the clearing prices in the 2019-2020 capacity auction that was conducted in March of 2019.

This analysis starts with a base case scenario that reflects the actual outcomes of the 2019-2020 PRA. We then produce scenarios that show the PRA clearing prices that would have resulted if the supply and demand were adjusted to:

a) disqualifying resources that would be known to be on outage during the summer peak period,
b) limit the capacity that can be sold to the deliverable ICAP amount, and
c) reflect the requirement to serve firm behind-the-meter load.

The individual scenarios were then combined to show the impact of implementing all of the recommendations together. In addition to evaluating the base case scenarios against the current capacity auction construct that relies on a vertical demand curve, we also conducted a series of similar sensitivities assuming a sloped demand curve. This has been a long-standing recommendation intended to allow the PRA to facilitate efficient investment and retirement decisions. The results of our analysis are shown in Table 12 below.

**Table 12: Alternative Capacity Auction Clearing Prices in 2019–2020 Planning Resource Auction**

| Alternative Capacity Auction Scenarios | Affected UCAP | Vertical Demand Curve | | Sloped Demand Curve | |
|---|---|---|---|---|---|
| | | Unconstrained Price | Constrained Price (MI) | Unconstrained Price | Constrained Price (MI) |
| Base Scenario | | $2.99 | $24.30 | $110.38 | |
| - Known Outages | 635.4 | $4.95 | $243.37 | $121.52 | $243.37 |
| - Undeliverable ICAP (Conventional Gen.) | 1,515.3 | $9.82 | $24.31 | $137.57 | |
| + Procurement for BTM Firm Load | 306.5 | $4.95 | $24.30 | $115.90 | |
| **Combination of Alternative Scenarios** | | | | | |
| - Known Outages, BTM Firm Load | 941.9 | $5.00 | $243.37 | $127.07 | $234.37 |
| - All Changes | 2,455.8 | $15.00 | $243.37 | $149.07 | $243.37 |

These scenarios show that improving the qualification of supply and calculation of demand can significantly change the capacity procurements and prices, particularly in constrained zones. Disqualifying resources that were known to be on outage throughout the entire summer peak period would have removed 635 MW of supply. This includes a 350 MW unit in Michigan that is on planned outage for the entire planning year. This results in Michigan being short of capacity and clearing at CONE. The other scenarios show that although the quantity effects may be substantial – totaling almost 2,500 MW together – the price effects are modest.

However, improving the representation of demand in the capacity market has a sizable effect. These cases show that the price in the PRA would have cleared between $110 and $150 per MW-day, depending on the implementation of other improvements. These prices more efficiently reflect the underlying supply and demand for capacity as discussed in Section VII.F.

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

MISO's historic accreditation methodology tended to provide excessive capacity credit to its resources because it did not account for: unreported outage and derates or any type of outage other than a forced outage. Additionally, the EFORd formula tends to under-weight forced outages. MISO attempted to address some of these issues by filing a Tariff change approved by FERC in March 2019 that reduces the accreditation of resources taking short-notice planned outages that occur during emergency conditions and have not received a safe harbor.[36] However, we evaluated this change and found that it had a very small effect, primarily because emergency events are so infrequent and because it does not include unreported outages and derates. Hence, it does little to address the accreditation concerns that we have raised.

Therefore, we have proposed additional accreditation changes to base resources' accreditation on their output during the tightest margin hours of the year, excluding planned outages approved more than two weeks in advance. This methodology would, therefore, include all types of outages and derates including those that are not reported. It would also focus on whether the resource is available when it is needed most – when the day-ahead supply margin (total supply minus total demand) is smallest (we use the tightest 5 percent of hours). We use GADs and CROW outage data from the previous three years to perform this analysis.

The results of this analysis are shown in Table 13 by major resource type. The table shows the amount of capacity in each resource category along with the current UCAP derate (the XEFORd rate), the UCAP derate with the initial change made by MISO in 2019, and the UCAP derate under the IMM proposed methodology.

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

| Resource Class | Capacity (MW) 1/ | Current UCAP Derate (XEFORd) | MISO RAN: Include Outages in Emergencies 2/ | IMM Proposal: Outages & Derates in Tightest Hours |
|---|---|---|---|---|
| Combined Cycle 3/ | 16,744 | 4.0 | 4.2 | 6.9 |
| Coal | 52,646 | 8.5 | 8.6 | 14.9 |
| Combustion Turbine (Gas) | 27,219 | 6.9 | 7.2 | 9.8 |
| Nuclear 3/ | 11,592 | 2.9 | 3.0 | 4.1 |
| Steam Turbine (Gas) | 12,456 | 18.4 | 18.8 | 22.8 |

1/ Includes units with awarded UCAP in 2019 that is not fully excluded. Excludes a small number of units that have an XEFORd of 0.
2/ Excludes a small number of additional units that are assigned a Class Average XEFORd.
3/ A few additional units are excluded from these categories due to anomalous outage patterns.

Table 13 confirms that the initial RAN changes to account for non-forced outages during emergencies will have little impact on the accreditation of resources. However, the changes proposed by the IMM show more significant impacts because it is more effective in estimating resources' expected contribution to maintaining reliability in the most critical hours. This is

36 Docket No. ER19-915-000.

particularly true for peaking resources that are rarely needed. They may appear to be available in most hours when they are not committed and if they fail to start the few times when they are committed, this failure will not be accurately reflected in their EFORd accreditation. Our proposed changes to the accreditation address this issue and a number of other concerns.

It is important to recognize that the estimated effects of the IMM proposal is based on historic data and would, therefore, not include likely responses by suppliers to this accreditation methodology. For example:

- Combined-cycle generators show an increase in the average UCAP derate from 4 percent to 6.9 percent, but this increase can be substantially mitigated by improving the timing of planned outages.
- Coal resources indicate an increase from an average of 8.5 percent to 14.9 percent, but these resources likewise could improve in their coordination of planned outages and increasing the advance notice for the planned outages.

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 proposal. 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.

***Discussion of Other Issues Affecting the Performance of the PRA***

*Transfer Constraint.* As part of the Settlement Agreement with SPP, MISO may schedule up to 2,500 MW of energy transfers from the MISO South subregion to the MISO Midwest subregion in real time. As in the prior year's planning process, MISO limited the transfer capability in the South to North direction to 1,500 MW. However, the constraint was not binding and, therefore, had no impact on clearing prices. Modeling the transfer constraint with a limit that reflects a probabilistic expectation of available transfer capability in real-time operations would allow MISO to more fully utilize its planning reserves in MISO South. We recommend that MISO adopt a new methodology for establishing the transfer limit in future PRAs.

*The PRA and Attachment Y Requests.* The PRA should assist suppliers in making efficient decisions regarding their resources, including whether to retire their units. In September 2018, FERC issued an Order accepting MISO's proposal to modify the PRA rules to allow units with Attachment Y retirement requests to participate in the PRA and, if they clear, to defer the effective date of the retirement.[37] Additionally, units under SSR contracts are allowed to participate in the PRA without undue risk by giving market participants with SSR contracts

37 "Order Accepting Tariff Revisions re Midcontinent Independent System Operator, Inc. under ER18-1636, et. al.,"FERC ER18-1636, issued September 25, 2018.

sufficient notice prior to termination to allow them to defer or rescind their retirement, which preserves their interconnection rights.

*External Resources.* In prior years, external resources that cleared MISO's capacity auction were counted towards the Local Clearing Requirement of the zone into which the resources had firm transmission service. This caused external resources to displace internal zonal resources to meet the Local Clearing Requirement and created potential reliability issues. FERC issued an Order in October 2018 accepting MISO's tariff filing that established external zones for capacity resources outside the MISO footprint, with the exception of Border External Resources that are directly connected to MISO and may be dispatched by MISO in an emergency event.[38]

Units with historical arrangements that may now see price separation between the External Zone pricing and the zone in which they have historically cleared will be eligible to receive a Historic Unit Consideration (HUC) that is an allocation of excess revenues from the auction back to LSEs with historical agreements or contracts through the maximum time period of the contract or two years, as long as it continues to meet eligibility requirements.

## F. Capacity Market Design

We consistently have 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 in the Resource Adequacy Construct. 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 PRA demand curve issue has come before the Commission recently as a result of the December 2017 re-filing of Module E by MISO. This re-filing was prompted by a remand of a Commission decision (see *NRG Power Marketing, LLC. v. FERC*, 862 F.3d 108 (2017)). Because MISO was requesting that the Commission find Module E to be just and reasonable, we intervened in the MISO Module E re-filing to protest the PRA demand curve.[39]

Our protest at FERC emphasized that the demand for capacity in the PRA continues to poorly reflect its true reliability value, which undermines its ability to provide efficient economic signals for investment and retirement decisions. The demand in MISO's planning resource auction is set at the level necessary to satisfy MISO's minimum planning reserve requirements

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38 "Order Accepting Tariff Filing re Midcontinent Independent System Operator, Inc. under ER18-2363," FERC ER18-2363, issued October 31, 2018.

39 See "Motion to Intervene Out of Time and Protest of the MISO Independent Market Monitor," filed February 8, 2018, in Docket No. ER18-462-000.

with the price capped at a deficiency price based on the cost of building a new resource. This single-quantity demand results in 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.

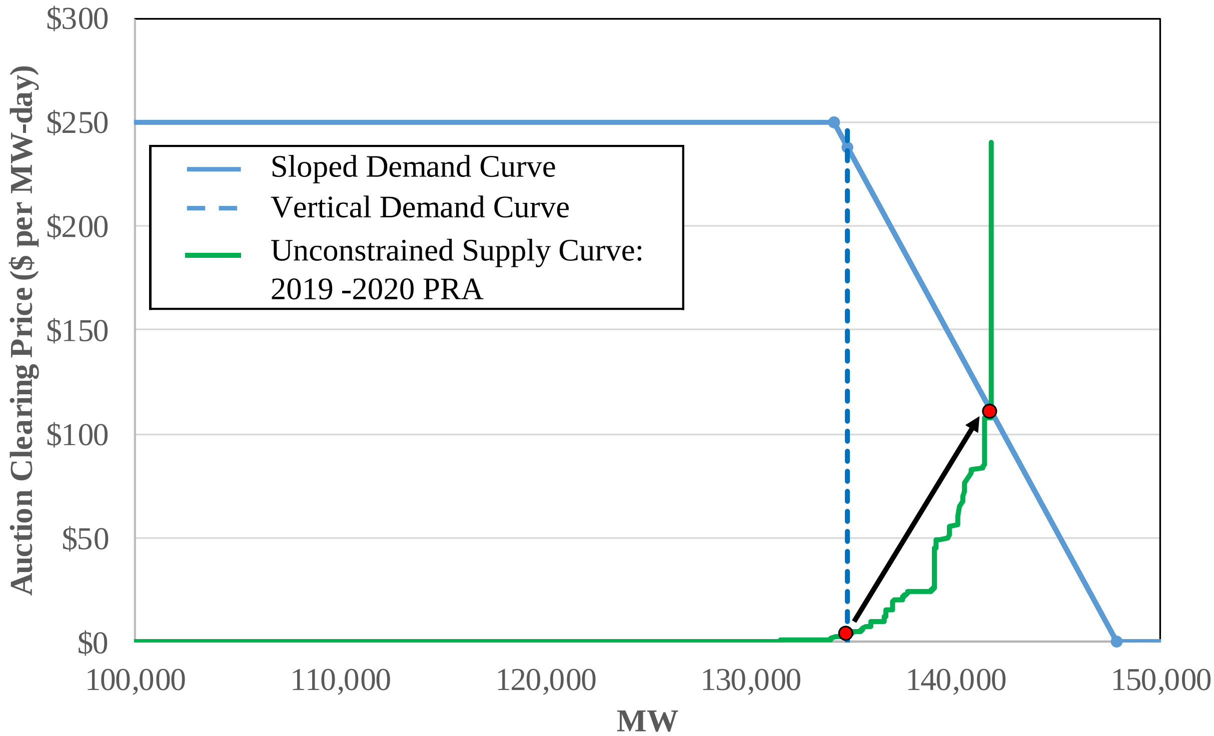
Like many of our previous *State of the Market Reports*, our protest of the MISO Module E filing sought to address this flaw by recommending that MISO implement a sloped demand curve. A sloped demand curve would produce more stable and predictable pricing, which would increase the capacity market's effectiveness 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 because competitive resources continue to retire or export to PJM.

To demonstrate the significance of the design flaw, we simulated the clearing price in MISO that would have prevailed in the 2019/2020 PRA if MISO employed sloped demand curves in the PRA (Appendix Section III.D describes the assumptions underlying this curve). Figure 38 depicts this simulation. The blue dashed line in the figure represents the vertical demand curve actually used in the auction, and the solid green line indicates the maximum amount of capacity in MISO that was not stranded behind transmission constraints. We constructed the supply curve using all capacity that was offered into the MISO auction at a price or self-supplied in Fixed Resource Adequacy Plans.

In the 2019/2020 MISO PRA, nearly 135 GW of capacity cleared at a clearing price of $2.99 per MW-day, except for zone 7 that was import-constrained and cleared at $24.30 per MW-day. In our sloped-demand-curve simulation, we found that:

- 142 GW of capacity cleared at a single MISO-wide price of $110.38 per MW-day.
- This price is more than 35 times the actual clearing price in most of MISO, which is a much more accurate reflection of the marginal reliability value of capacity in MISO.
- This is roughly half of the CONE for new resources in MISO; and
- This price would be sufficient to motivate competitive suppliers to keep economic resources from retiring or exporting their economic resources.

**Figure 38: Supply and Demand in 2019–2020 PRA**




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***

Based on the simulation described in the prior section, we estimated how improving the design of the PRA would have affected various types of market participants in the 2019/2020 PRA. We calculated the simulated settlements for each participant based on their net sales. We then aggregated the participant-level results into three categories: competitive suppliers, competitive retail LSEs, and vertically-integrated utilities, which is shown in Table 14.

**Table 14: Effects of Sloped Demand Curve by Type of Participant**
2019–2020 PRA ($ Millions)

| Type of MP | Net Revenue Increases | Net Revenue Decreases | Total |
|---|---|---|---|
| Vertically-Integrated LSEs | $ 348 | -$ 316 | $ 32 |
| Merchant Generators | $ 390 | | $ 390 |
| Retail Choice Load | | -$ 422 | -$ 422 |

This table shows that the vertically-integrated LSEs would have benefited in aggregate by $32 million from the use of the sloped demand curve. The effects on the vertically-integrated LSEs are very small because they tend to self-supply most of their requirements through owned generation or bilateral purchases. Hence, the vertically-integrated LSEs' exposure to the PRA price is limited. Overall, 42 percent of these participants would benefit by implementing a sloped demand curve because they can sell their excess resources at an efficient price.

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 significantly more revenue (close to $400 million) through the PRA, providing more efficient signals to maintain existing resources and build new resources. This effect will grow as capacity margins fall in MISO.
- Likewise, costs borne by competitive retail loads would have risen by $422 million. This is desirable because it provides efficient incentives for these LSEs to arrange for their own capacity needs and contribute to satisfying the region's resource adequacy needs.

### *Other Recommended Improvements to the PRA*

Although a sloped demand curve is the most important design improvement, we have also recommended that MISO consider the following additional improvements.

*Seasonal Capacity Market.* A seasonal market would better align the revenues and requirements of capacity with the value of the capacity. In its initial work on a possible seasonal capacity market, MISO proposed two seasons: summer and winter. We have recommended that MISO define 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
- 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.

*Defining Capacity Zones.* MISO's current capacity zones cannot be smaller than an entire LBA. However, capacity is sometimes needed in certain load pockets within LBAs. A good example of this type of requirement is the Narrow Constrained Areas (NCAs) in MISO South where the addition of fast-start capacity would be extremely valuable. Hence, we recommend that MISO's local resource zones be established based primarily on transmission deliverability and local reliability requirements.

# VIII. External Transactions

## A. Overall Import and Export Patterns

Imports and exports play a key role in MISO because it has 12 interfaces with a total interface capability of 14 GW. Hence, the magnitude of the changes in imports and exports in response to prices can be very large and significantly affect market outcomes and reliability. Interface price differences create incentives for physical schedulers to import and export between MISO and adjacent areas. As in prior years, MISO remained a substantial net importer in 2018:

- Day-ahead and real-time net imports averaged 4.2 and 4.8 GW, respectively.
- MISO's largest and most actively-scheduled interface is the PJM interface. MISO was a net importer from PJM in 2018.
  - Hourly average real-time imports from PJM were 1.9 GW.
  - 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. However, participants must schedule transactions at least 20 minutes in advance and, therefore, must forecast the price differences. Additionally, the lack of RTO coordination of participants' schedules causes aggregate changes in transaction schedules to be far from optimal. To evaluate the efficiency of interregional 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 2018, we found that:

- Only slightly more than half of the transactions with PJM and SPP were scheduled in the profitable direction, and
- Roughly 60 percent of those scheduled in real time and settling at the real-time prices were profitable.

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 interchange or less interchange than was scheduled. 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.

Since its inception, there has been almost no participation in CTS. The average quantity of CTS transactions offered and cleared in 2018 were 2.9 MW and 0.32 MW, respectively. We have previously asserted that high transmission and energy charges have likely deterred traders from using CTS in lieu of traditional transaction scheduling. To verify this assertion, we conducted an analysis comparing:

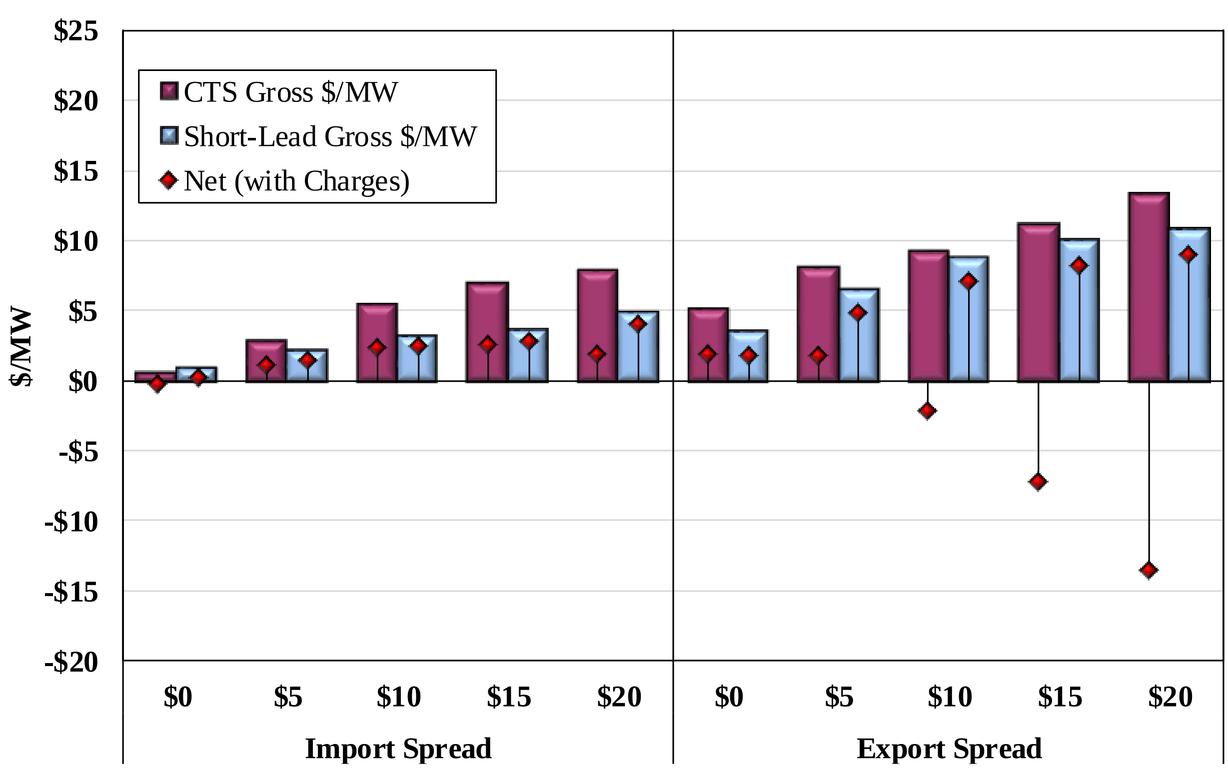
- a scheduling strategy using CTS offers, to:
- a strategy using short-lead time transactions scheduled 30 minutes ahead (i.e., the traditional means of scheduling transactions).

Excluding the charges applied to CTS transactions, the CTS transactions should be more profitable if the mechanism operates effectively because participants are able to submit an offer price. In contrast, the traditional scheduling mechanism requires participants to submit transactions that are not price-sensitive based on their expectations of the future price spread. We limited the time period of our analysis to October 2, 2017 through June 12, 2018 because a significant forecasting bias was introduced after June 12 that was not resolved until March 2019. The results of our analysis are shown in Figure 39 below, which compares:

a) 1 MW CTS transactions offered at various target spreads; to

b) 1 MW short-lead scheduled transactions initiated when the actual real-time interface price spread 30-minutes prior to the transaction exceeded the applicable target spread.

**Figure 39: CTS vs. Traditional NSI Scheduling**
October 2017 – June 2018



Consistent with expectations, this analysis shows that on a gross basis, the CTS strategies are *consistently more profitable* than the short-lead strategy. This indicates that the CTS forecast prices, while imperfect, are more accurate than lagged real-time LMPs. Importantly however, the CTS strategy does not perform well on net because of reservation fees that are incurred regardless of whether the CTS offers clear, particularly for exports. The discrepancy is not as severe for imports because the reservation fees are lower and the CTS transactions clear at a higher rate.

Nonetheless, the fact that CTS strategies are consistently more profitable absent the charges, but consistently less profitable with the charges suggests that *the charges are undermining the ability of the participants and the market to benefit from CTS*. A comparable mechanism is in place between the New York ISO and ISO New England and is widely used, in part because no charges are applied to these transactions. Hence, we continue to recommend that MISO eliminate the charges to the CTS transactions and request that PJM do the same.

## C. Interface Pricing and External Transactions

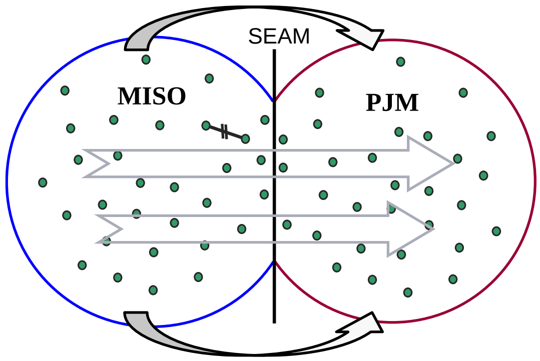
Each RTO posts its own interface price at which it will settle with physical schedulers wishing to sell and buy power from the neighboring RTO. Participants will schedule between the RTOs to arbitrage differences between the two interface prices. Interface pricing is essential because:

- 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 their 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.

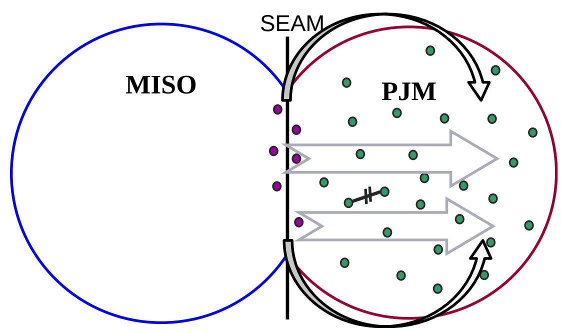
Like the LMP at all generation and load locations, the interface price includes: a) the SMP, b) a marginal loss component, and c) a congestion component. For generator locations, the source of the power is known and, therefore, congestion effects can be accurately calculated. In contrast, *the source 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 below on 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. However, PJM assumes the power sources and sinks from the border with MISO, as shown in the second figure on the right below. 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 remain concerned that PJM's interface definitions set inefficient interface prices. We believe that the inaccuracy of PJM's congestion components plays a major role in causing MISO to be a net importer from PJM (1.9 GW on average). For example, in 2018:




- On average, MISO's system marginal price was almost 20 percent lower than PJM's, suggesting that MISO should be exporting power to PJM.
- However, PJM's average congestion component at the interface is large, which encourage participants to schedule large quantities of exports to MISO on the basis that they presumably relieve congestion in PJM.
- If exports do not actually provide this much relief, PJM will incur substantial excess congestion costs and the dispatch will be inefficient.

These results underscore the significance of these interface pricing flaws. We also believe that PJM's inaccurate interface prices led to inefficient day-ahead schedules that inflated the market-to-market costs incurred by PJM. For example, we estimated that PJM's congestion settlements at the MISO interface resulted in overpayments to transactions of almost $45 million in 2015.[40]

### *Evaluation of the PJM-MISO Common Interface Definition*

In 2012, we first identified a problem in the MISO and PJM market designs that resulted in incorrect pricing of congestion along the MISO-PJM seam. Because both markets priced each other's congestion on market-to-market constraints, their interface prices could include redundant congestion that distorted the incentives to schedule interchange between the markets. In response to this issue, MISO adopted a new definition for the PJM interface in June 2017. This "Common Interface" consists of 10 generator locations near the PJM seam with five points

40 See the *2015 State of the Market Report for the MISO Electricity Markets*, Potomac Economics, June 2016.

in MISO's market and five in PJM. Each of the 10 locations has a 10 percent weight in the final interface price. The Common Interface definition has reduced the magnitude of inefficiency related to most of the market-to-market constraints in the real-time market.

However, the Common Interface has introduced new inefficiencies that more than offset the benefits of improved real-time pricing of the market-to-market constraints:

- Market-to-market constraints are rarely coordinated in the day-ahead market, which has caused the common interface to produce inefficient and erratic transaction incentives.
- More significantly, non-market-to-market congestion is mispriced using the common interface definition. Because the 10 points are not an accurate assumption for the source for imports or the sink for exports, the resulting congestion estimates are not accurate.

In aggregate, the common interface has led to larger average errors and volatility at the interface. Based on our evaluations of the common interface, we conclude that this approach was a mistake and should not be considered at the SPP interface where the redundant settlements of congestion are still occurring. We encourage MISO and SPP to adopt accurate interface definitions that will settle interchange congestion accurately.

#### *Interface Pricing for Other External Constraints*

In addition to PJM market-to-market constraints, MISO also activates constraints located in external areas when neighboring system operators call TLRs and MISO re-dispatches its generation to meet its 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 of these congestion payments, they 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.

One should expect that these issues will result in inefficient schedules and higher costs, so we continue to recommend MISO remove all external congestion from its interface prices.

# 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 2018. Market power in electricity markets exists when a participant has the ability and incentive to raise prices. Market power can be indicated by a variety of empirical measures. In this section we discuss measures that are applicable to the MISO markets.

## 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. A more concentrated market will have a higher HHI index. Market concentration is low for the overall MISO area (591) but relatively high in some local areas, such as the WUMS Area (2708) and the South Region (3673). In MISO South, a single supplier operates nearly 60 percent of the generation. However, the 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 larger differences (i.e., excess supply) result 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 NCAs and the Broad Constrained Areas (BCAs) that are defined for purposes of market power mitigation. NCAs are chronically constrained areas that raise more severe potential local market power concerns (i.e., 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:

- Eighty-seven percent of the active BCA constraints had at least one pivotal supplier, and at least one BCA constraint with a pivotal supplier was binding in most intervals.
- Nearly 100 percent of constraints in the two MISO South NCAs had a pivotal supplier.
- The MISO Midwest NCAs had pivotal suppliers on 95 percent of the active constraints.

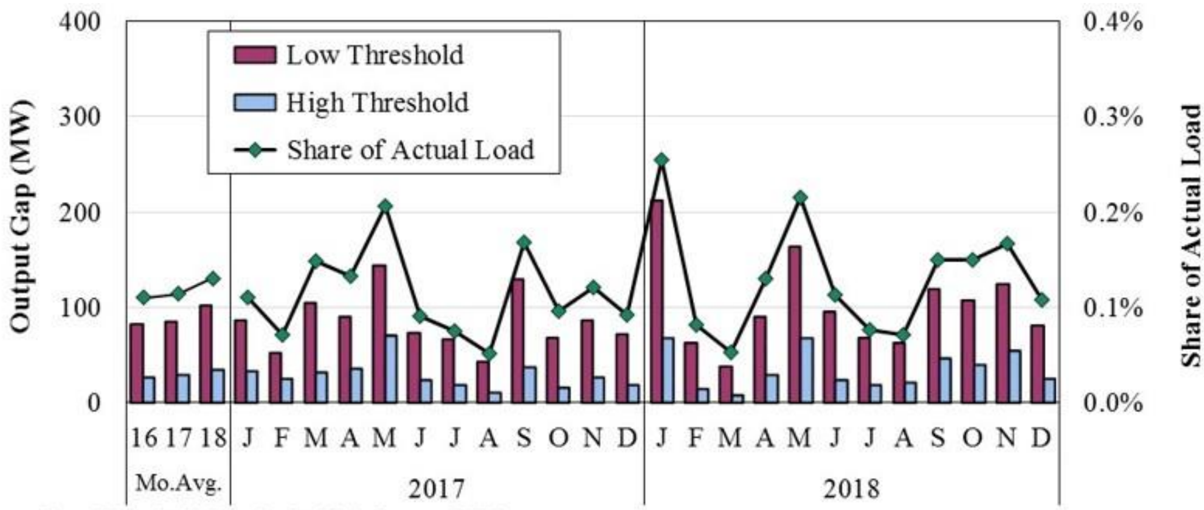
Overall, these results indicate that local market power persists, with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

## 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 *-1.2* percent in 2018, varying monthly from a high of *2.7* percent to a low of *-5.7* percent. The low average price-cost mark-up indicates that MISO's energy markets produced very competitive results.

The next figure 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. Additionally, the output gap includes units that are online and withholding energy by submitting inflated energy offers, as well as units that were not committed because of inflated economic or physical offer parameters.

**Figure 40: Economic Withholding – Output Gap Analysis**
2017–2018




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

| | 16 | 17 | 18 | J | F | M | A | M | J | J | A | S | O | N | D | J | F | M | A | M | J | J | A | S | O | N | D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Offline | 12 | 6 | 12 | 10 | 6 | 5 | 11 | 14 | 4 | 2 | 2 | 16 | 0 | 0 | 0 | 30 | 0 | 0 | 3 | 40 | 11 | 4 | 8 | 17 | 17 | 6 | 3 |
| Online | 71 | 79 | 90 | 77 | 46 | 100 | 79 | 130 | 69 | 65 | 41 | 114 | 68 | 86 | 72 | 182 | 63 | 37 | 88 | 124 | 85 | 64 | 55 | 102 | 90 | 118 | 78 |

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

| | 16 | 17 | 18 | J | F | M | A | M | J | J | A | S | O | N | D | J | F | M | A | M | J | J | A | S | O | N | D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Offline | 10 | 5 | 10 | 10 | 6 | 5 | 11 | 14 | 4 | 2 | 2 | 12 | 0 | 0 | 0 | 20 | 0 | 0 | 2 | 33 | 8 | 3 | 8 | 16 | 16 | 5 | 3 |
| Online | 15 | 23 | 24 | 22 | 19 | 27 | 24 | 55 | 20 | 16 | 9 | 24 | 15 | 26 | 19 | 46 | 14 | 7 | 26 | 33 | 15 | 15 | 13 | 30 | 24 | 48 | 21 |

The figure shows that the average monthly output gap level was 0.1 percent of load in 2018, which is effectively *de minimus*. Although these aggregate results raise no overall competitive concerns, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

## C. Summary of Market Power Mitigation

Instances of market power mitigation in 2018 were appropriate and effectively limited the exercise of market power. The imposition of mitigation in the energy market remained infrequent in 2018, and although the number of instances of RSG mitigation rose in 2018, the total dollar amount of RSG mitigation fell relative to 2017.

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 it exceeds the conduct threshold and the offer 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 two types of constrained areas that may be subject to mitigation: BCAs and NCAs. The market power concerns associated with NCAs are greater because they are chronic. As a result, conduct and impact thresholds for NCAs can be substantially lower than they are for BCAs. They depend on the frequency with which NCA constraints bind. The lower mitigation thresholds in the NCAs generally lead to more frequent mitigation there than in BCAs, even though the system has many more BCAs.

Energy offer mitigation did not occur in the day-ahead market and decreased in the real-time market in 2018. Mitigation was imposed in less than one percent of hours in the real-time market. 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 not imposed in any hours in the day-ahead market. 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.

In 2018, total RSG mitigation fell 3 percent as higher mitigation for VLR constraints was offset by lower mitigation of RSG paid to resources committed for constraint relief. VLR requirements are one frequent cause of commitments for which participants may be paid RSG. Most VLR commitments are in MISO South and are subject to tighter mitigation thresholds because competition to satisfy these requirements is limited. In August 2018 MISO instituted a new local Operating Guide in MISO South, creating a new VLR load pocket to address capacity needs in the area.

## D. Introduction of Dynamic NCAs

The market power mitigation measures are effective, in part, because MISO has the authority to designate NCAs in chronically-constrained areas, which results in the application of tighter conduct and impact thresholds to address the heightened market power concerns in these areas. An NCA is an area defined by one or more constraints that are expected to bind for at least 500 hours in a 12-month period. Consequently, when transitory conditions arise that create a severely-constrained area with pivotal suppliers, an NCA is often not defined because it is not expected to exhibit binding constraints for 500 hours in a 12-month period.

Transitory congestion can result in substantial local market power. This often occurs when system changes occur related to transmission outages or generation outages. Once the congestion pattern begins, suppliers may recognize that their units are needed to manage the constraints and exercise market power under the relatively generous BCA thresholds.

To address this concern, we recommended that MISO expand Module D of its Tariff to allow it to establish "dynamic" NCAs when transitory conditions arise that lead to sustained congestion. We recommended that the threshold for the dynamic NCA be set at $25 per MWh and be triggered by the IMM when mitigation would be warranted under this threshold *and* congestion is expected in at least 15 percent of hours (more than double the rate that would be required to permanently define an NCA). MISO filed this proposal and it was implemented in January 2018. The ability to define Dynamic NCAs will help ensure that transitory network conditions do not allow a substantial exercise of local market power.

Although a number of cases that would have warranted mitigation occurred in past years, no conditions emerged in 2018 that warranted the definition of a Dynamic NCA. This was partly due to the fact that severe transitory congestion caused by transmission outages or other factors was not frequent in 2018 and was potentially due to the deterrence effects of these measures.

# X. Demand Response

Demand Response improves operational reliability, contributes to resource adequacy, reduces price volatility and other market costs, and mitigates supplier market power. Therefore, it is important to provide efficient incentives for the development of DR and to integrate it into the MISO markets in a manner that promotes efficient pricing and other market outcomes. DR consists of several types of resources. DR can participate in MISO either through the energy markets as Demand Response Resources Type I and Type II (DRR), Emergency Demand Response Resources (EDR), or as Load Modifying Resources (LMR). In addition to DR, LMRs include Behind-the-Meter Generation (BTMG) that do not have direct interconnection to MISO.

## A. Summary of Demand Response Participation

Table 15 shows overall DR participation in MISO, NYISO, and ISO-NE in the prior three years.

**Table 15: Demand Response Capability in MISO and Neighboring RTOs**
2016–2018

| | | 2016 | 2017 | 2018 |
|---|---|---|---|---|
| **MISO[1]** | | **10,454** | **11,495** | **12,931** |
| | Behind-The-Meter Generation | 3,822 | 3,822 | 4,496 |
| | Load Modifying Resource | 4,616 | 6,112 | 7,137 |
| | DRR Type I | 525 | 620 | 621 |
| | DRR Type II | 75 | 0 | 3 |
| | Emergency DR | 1,416 | 941 | 674 |
| **NYISO[3]** | | **1,267** | **1,237** | **1,314** |
| | Special Case Resources - Capacity | 1,192 | 1,221 | 1,309 |
| | Emergency DR | 75 | 16 | 5 |
| | Day-Ahead DRP | 0 | 0 | 0 |
| **ISO-NE[4]** | | **2,598** | **2,655** | **2,988** |
| | RT DR Resources/DR Assets | 702 | 683 | 262 |
| | On-Peak Demand Resources | 1,386 | 1,418 | 2,214 |
| | Seasonal Peak Demand Resources | 510 | 554 | 512 |

[1] Registered as of December 2018. All units are MW.

[2] Roughly 1/3 of the EDR are also LMRs.

[3] Registered as of July 2018. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.

[4] Registered as of December 1, 2018. Source: ISO-NE Demand Response Working Group Pesentation.

The table shows that MISO had almost 13 GW of DR capability available in 2018, which is a larger share of the total capacity than in the other RTOs we monitor. 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 BTMGs.

Although 26 DRRs were active in the MISO markets in 2018, they only cleared a small amount of energy and reserves in the MISO markets. Of these, 23 units were DRR Type 1 (non-dispatchable DRRs) and three were DRR Type 2. As MISO's surplus capacity dissipates, DR resources are expected to be deployed more frequently to satisfy peak loads and to respond to system contingencies. It is important, therefore, to ensure that real-time markets produce efficient prices when DR resources are deployed.

## B. Accessibility of LMRs and Other Emergency Resources

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. LMRs were deployed in MISO South once in April 2017, twice in January 2018, and once in September 2018. In January 2019, LMRs were deployed twice in the Central and North Regions. We discuss the events in detail in Section III of this Report.

LMRs and other emergency resources come in a number of different forms. LMRs are either DR or BTMGs that clear in MISO's annual capacity auction, while emergency-only ("AME") are internal generators that indicate through their commitment status that they are only available during a declared emergency. The availability of each of these types of resources is governed by their obligations and the offer parameters they submit to MISO.

Prior to a recent FERC filing, LMRs were only obligated to curtail load up to five times during the summer months, and they could be subject to a notification time of up to 12 hours. However, they could only be scheduled when MISO declared a severe emergency – a Maximum Generation Event Level 2b or higher. This made LMRs accessible only after all other resources have been utilized in emergencies. Similarly, AME resources are only available after an EEA 1 has been declared and may have long notification times that prevent MISO from utilizing them.

In February 2019, FERC approved MISO's Tariff revisions that expanded MISO's access to LMRs.[41] LMRs are now required to provide MISO with their best availability in all seasons, with the requirement that they are still fully available throughout the summer. 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. This should be helpful because it will shorten notification times that have previously limited LMRs' availability.

41 See "Order Accepting Tariff Revisions, Subject to Condition, and Granting Waiver," issued February 19, 2019, under Docket No. ER19-650-000.

We evaluated the availability of these resources during emergency events that occurred in 2017, 2018, and early 2019 in which LMRs were called (January 17, 2018, September 15, 2018, and January 30, 2018). Figure 41 below shows this evaluation, subdividing the LMRs and other emergency resources by notification time. To show the effect of MISO's filing, we show the quantity of LMRs that cleared in 2018 vs. 2019 by notification time. The dark green and blue bars represent resources that cleared in the 2018 capacity auction, and the light green and blue bars represent resources that cleared in the 2019 capacity auction. The average offered AME resources by combined startup and notification times are indicated by the maroon bars. These quantities have tended to be small during peak hours and are much larger during off-peak hours.

**Figure 41: Availability of Emergency Resources during Events**

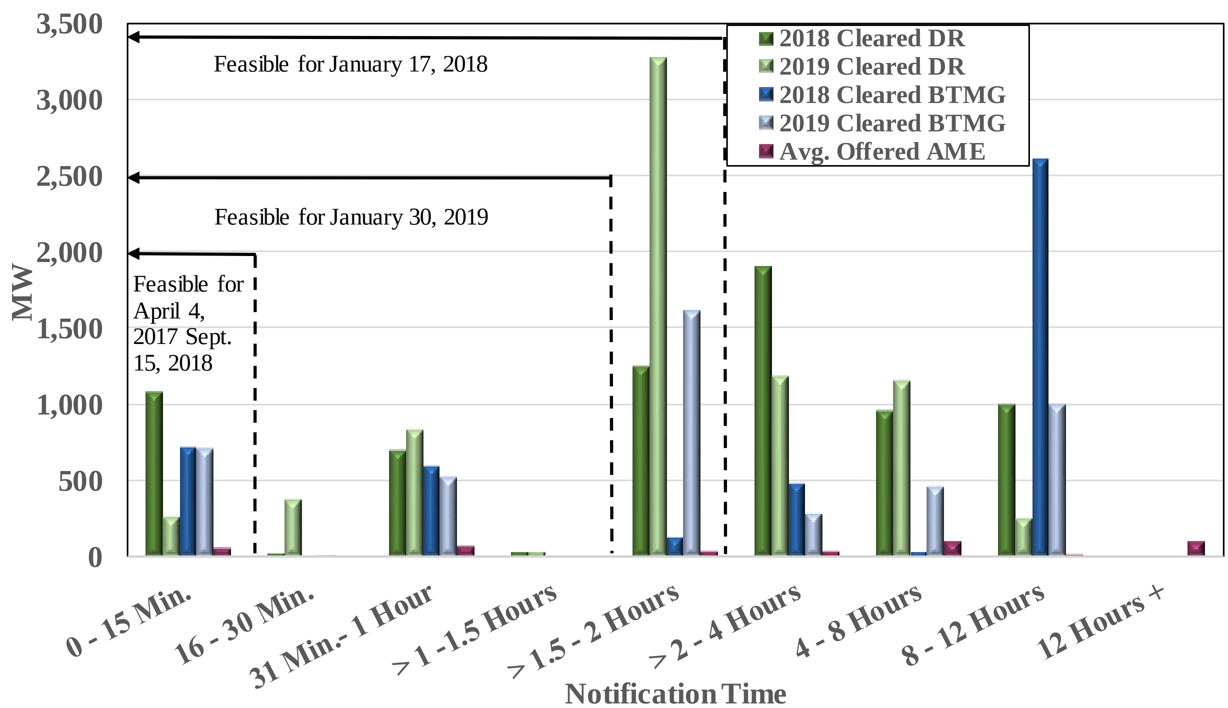



Figure 41 shows that the notification times for LMRs have fallen sharply after the Tariff changes (i.e., the light blue and green bars have shifted leftward from the dark blue and green bars). Only 39 percent of emergency resources that cleared MISO's 2018-2019 capacity auction were available within 2 hours, compared to 63 percent of all emergency resources that cleared MISO's 2019-2020 capacity auction. This is a significant improvement that resulted from MISO's LMR RAN filing. Findings for individual events include:

- April 4, 2017: This event did not occur during the summer so if resources only obligated to be available in the summer are excluded, only three percent of all emergency resources would have been available during the event, primarily because the event was called only ten minutes in advance of the emergency. Given MISO's LMR changes in early 2019, if one includes all LMRs and emergency resources, 16 percent of the emergency resources would have been available during this event based on the 2018 values and 8 percent based on the 2019 capacity values.

- January 17, 2018: MISO declared this emergency two hours before the critical period of the event. Only seven percent of the emergency resources could have been scheduled in time to provide meaningful assistance. If the summer-only resources are included, this percentage rises to 39 percent, based on the 2018 capacity values. Based on the 2019-2020 emergency resources, 63 percent of the cleared capacity would have been available because notification times have fallen.
- September 15, 2018: MISO declared the emergency 15 minutes before the resources were expected to perform and well after they were needed. Only 16 percent of emergency resources would have been available during this event based on 2018-2019 capacity values, and only 8 percent based on the 2019-2020 capacity values. MISO had to schedule emergency transactions into the South on this day because of the lack of available emergency resources.
- January 30, 2019: MISO's declaration of the EEA 2 level emergency approximately one and a half hours in advance granted MISO access to approximately 27 percent of the total emergency-only resources, based on the 2018 capacity auction results. Were MISO relying on emergency-only resources cleared in the 2019-2020 auction, only 23 percent of emergency-only resources would have been available.

These case studies show that a large number of emergency resources are inaccessible during the most critical emergency periods. This poses a reliability issue given MISO's reliance on them to satisfy its resource adequacy needs.

Additionally, LMR demand response load with long notification times must generally continue to be served along with other firm load if they are not scheduled well in advance. This calls into question the capacity credit MISO grants LMR-DRs under Module E, which is equal to the curtailment quantity *plus* losses and the Planning Reserve Margin. This is only reasonable if the RTO is confident that it will not have to serve this load during emergencies. Hence, we are recommending changes in Module E to address these issues. This includes providing capacity credits under Module E that reflect emergency resources' expected availability, recognizing both their historic performance and their startup notification times.

# XI. Recommendations

Although MISO's markets continued to perform competitively and efficiently in 2018 overall, we recommend a number of improvements in MISO's market design and operating procedures. These twenty-nine recommendations are organized by the aspects of the market that they affect:

- Energy Pricing and Transmission Congestion: 11 total, 2 new.
- Operating Reserves and Guarantee Payments: 3 total, 1 new.
- Dispatch Efficiency and Real-Time Market Operations: 6 total, 1 new.
- Resource Adequacy: 9 total, 2 new.

Twenty-three of the recommendations discussed below were recommended in prior State of the Market Reports. This is not surprising because some of the recommendations can require substantial software changes, stakeholder review and discussions, and regulatory filings or litigation regarding Tariff changes. Since these processes can be time consuming and software changes must be prioritized with other software projects, recommendations can take multiple years to complete.

MISO addressed five of our past recommendations in 2018 or early 2019. In October 2018, MISO provided the MISO Board of Directors a detailed summary of MISO's review and response to the outstanding IMM recommendations.[42] We discuss recommendations that have been addressed at the end of this section. Included in this section is also one recommendation that MISO has not agreed to pursue and we are removing pending further analysis of market outcomes. For any recurring recommendation, we include a discussion of the progress MISO has made to date and next steps required to fully address the recommendation.

## C. 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, longer-term forward prices will be determined by expectations of the level and volatility of prices in the real-time market. Therefore, one of the highest priorities from an economic efficiency standpoint must be to produce real-time prices that accurately reflect supply, demand, and network conditions. A number of the following recommendations address this area.

42 See Memorandum MISO Response to the IMM 2017 State of the Market Report, from Clair Moeller President, to MISO Market Committee of the Board of Directors, October 2018.

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

Emergency pricing is a key element of the MISO market because it is intended to ensure that prices are set that efficiently reflect emergency conditions during the events. These prices, in turn, facilitate efficient responses that allow MISO to resolve the emergency.

The performance of the emergency pricing can be assessed because MISO has experienced a number of emergencies over the past two years. Our evaluation of MISO emergency pricing has revealed some important observations:

- The default emergency price floors have not been established at reasonable levels. The default floors are set by a supplier's offer, which has resulted in them often being inefficiently low and can result in them being inefficiently high.
- The emergency pricing model currently has a flaw that causes it to calculate ex post RDT flows incorrectly when interchange transactions such as emergency energy purchases are dispatched down during regional emergencies.

Therefore, we recommend that MISO implement fixed emergency default floors at efficient price levels that reflect the severity of the emergency and correct the flaw in the RDT flow calculation.

Status: This is a new recommendation.

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

MISO currently employs a 1.5 percent generator shift factor ("GSF") 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 a limited number of constraints, which are generally at lower voltage levels, where employing a 1.5 percent cutoff eliminates most or all of the economic relief available to manage the constraint. This can greatly increase the costs of managing the constraints and can, in some cases, raise reliability concerns. In 2018, $70 million in congestion occurred on such constraints.

To improve the management of congestion on these constraints, we recommend that MISO implement the capability to employ a lower GSF cutoff for the dispatch model for a limited number of constraints. In addition to improving economic efficiency, this will also address some M2M settlement issues that arise because the market flows calculated for market-to-market settlements do not employ a GSF cutoff.

Status: This is a new recommendation.

### 2017-1: Improve the market power mitigation rules

Over the past few years, the IMM identified a number of potential improvements to Module D Mitigation authority that are modest in scope and impact, but together will ensure that the market power mitigation provisions are fully effective.

The changes in the market power mitigation rules include:

- Modify the impact test and sanction provisions to include the impact of negative prices in order to effectively mitigate conduct whose effect is to lower prices at locations and aggravate transmission constraints.
- Modify the price impact threshold for ancillary services products to better reflect the prevailing clearing prices.
- Improve the generation shift factor cutoff for the application of BCA mitigation.
- Improve certain aspects of the market power mitigation sanction calculations.

Status: MISO agrees with this recommendation and MISO has indicated that it will work with the IMM to review specific proposed Tariff changes, to engage the stakeholders, and accommodate the changes in its systems and processes. MISO is targeting a FERC filing in the third quarter of 2019.

Next Steps: Draft Tariff redlines were shared with stakeholders at the June Market Subcommittee with a related feedback request. Final redlines are expected to be filed in July. Pending the filing and FERC approval, the changes are expected to be implemented in the third quarter 2019.

### 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. For example, if real-time prices are $40 per MWh in MISO and $25 per MWh in PJM, the CTS will increase net imports into MISO and save $15 per MWh. Hence, these transactions give the RTOs the ability to dynamically schedule the interface and lower the costs of serving load in both regions.

We had advised that the RTOs not 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, which are substantial. Given that a small portion of the offered transactions are scheduled, the reservation charges alone translate to $2.15 per MWh on scheduled imports and more than $6 per MWh on scheduled exports and virtually eliminate the incentive to submit CTS bids and offers. This is consistent with reality – CTS offers were small initially in November 2017 but have fallen consistently and were effectively zero for the majority of months in 2018.

This is regrettable because CTS promises substantial savings and required considerable resources to implement. Therefore, we recommend that MISO unilaterally eliminate all charges from CTS transactions. Although MISO should encourage PJM to do the same, there is no reason to wait for PJM to agree to eliminate its charges. MISO should also eliminate the requirement that participants reserve transmission for CTS transactions since the RTOs can make interface adjustments by directly utilizing any and all available transmission capability in real time. Hence, there is no reason to require participants to reserve transmission for these transactions.

Status: 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. Although we fully support this intention, it is separable from the negative effects of the charges so both sources of dysfunction in the CTS should be addressed.

Next Steps: This report shows that CTS transactions would not only be profitable, but more profitable than conventional scheduling, but for the transmission charges. Since these charges are inefficient and uneconomic, we continue to encourage MISO to eliminate them while working on the other more difficult changes that may be pursued over the longer term. MISO is continuing to evaluate CTS, and this is aligned as Roadmap Item #66.

### 2016-1: Improve shortage pricing by adopting an improved operating reserve demand curve reflecting the expected value of lost load

We recommend that MISO reform its ORDC. Because it is the primary determinant of the shortage pricing in MISO's energy markets, establishing an ORDC that reflects reliability is essential. MISO's current ORDC does not reflect reliability value, overstating the reliability risks for small, transient shortages and understating them for deep shortages. Additionally, PJM's recent changes will price 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.

An optimal or "economic" ORDC would reflect the "expected value of lost load", equal to:

*probability of losing load * net value of lost load (VOLL)*

The economic ORDC has substantial advantages. The shortage pricing under the economic ORDC will track the escalating risk of losing load. In the range where most shortages occur, the economic ORDC is sometimes higher and sometimes lower than MISO's current curve, so it should not substantially increase consumer costs for these shortages. The resulting prices will send more efficient signals for participants to take actions in response to the shortage, which maintain the reliability of the system. Additionally, this change will be essential as MISO integrates larger quantities of renewables because it will be pivotal in compensating flexible resources that can start quickly and ramp rapidly to compensate for the uncertain output of the intermittent resources.

For MISO to implement this recommendation, it would need to update its VOLL assumption and determine the slope of the ORDC based on how capacity levels affect the probability of losing load.

Status: MISO has indicated general agreement with the recommendation. MISO intends to study and pursue an improved ORDC, but this item is in the Parking Lot in the Market Roadmap process.

Next Steps: We have performed a detailed analysis to support a more efficient ORDC. The next step is for MISO to move this project from the Roadmap Parking Lot and to activate the study.

### 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. In other words, MISO can only deny or reschedule a planned outage if it threatens reliability. 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 2018, multiple simultaneous generation outages contributed to almost $350 million in real-time congestion costs – nearly 25 percent of all 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. It can deny or move outages if doing so will result in "significantly reduced congestion costs."[43] The ISO New England program has been found to have been very effective at avoiding unnecessary congestion costs.[44]

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.

43 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.

44 *Ibid.*

Status: MISO indicated agreement with the issue but has not supported seeking additional outage coordination authority. It is considering other improvements under the Resource Availability and Need (RAN) initiative. MISO's plans to improve the existing outage coordination process is being enhanced with a future implementation target, but this is unlikely to address the intent of this recommendation.

Next Steps: Consider filing for increased authority to coordinate outages.

### 2015-1: Expand eligibility for online resources to set prices in ELMP and suspend pricing by offline resources

Our analysis continues to indicate that, even with the Phase II changes discussed below, ELMP has not been fully effective in allowing online peaking resources to set prices when they are the marginal source of supply in MISO. This can be attributed to:

- The eligibility rules that only allow 6.8 percent of the online peaking resources to potentially set prices; and
- Modeling assumptions governing the ability of peaking resources to ramp down and other resources to ramp up in the ELMP model.

To address these factors and allow peaking resources to set prices efficiently, we recommend:

- Expanding the price-setting eligibility to include peaking resources committed in the day-ahead market;
- Relaxing the ramp-down limitation for peaking resources in the ELMP model; and
- Establishing constraints to ensure the quantity of capacity (energy plus reserves) does not increase or decrease in the ELMP model from the physical dispatch in the UDS.

In addition, we continue to find that ELMP's offline pricing has generally resulted in inefficiently-low ELMP prices during shortage conditions. The offline peaking resources that set prices are rarely utilized and economic in the periods in which they set prices. Hence, we continue to find that it is adversely affecting MISO's real-time prices and recommend that MISO suspend the offline pricing.

Status: MISO's implementation of the Phase II changes in 2017 to expand ELMP eligibility for online resources, including expanding ELMP eligibility to online resources that can be started within 60 minutes (previously limited to 10 minutes) resulted in only modest improvements. MISO's response in 2018 indicates that it agrees with the recommendation to allow fast-start Resources committed in the day-ahead market to set prices. MISO has determined an implementation date in the third quarter of 2019.

MISO is also evaluating the relaxation of the ramp constraints on Fast Start Resources and the recommendation to discontinue allowing offline fast-Start resources to set prices for congestion management. MISO discussed the ramp constraint evaluation in an ELMP III whitepaper and plans to complete the evaluation of offline fast-start pricing in the third quarter of 2019.

Next Steps: We recommend that MISO continue to assign a high priority to implementing the recommended changes to the ELMP model to allow it to set efficient real-time prices.

### 2015-2: Expand utilization of temperature-adjusted and short-term 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 temperature-adjusted ratings. 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 system conditions (e.g., ambient temperatures, wind forecasts, humidity). Our analysis showed potential savings from reduced congestion costs of $94 and $78 million in 2017 and 2018, respectively, if transmission owners had provided temperature-adjusted ratings.

Additionally, the transmission owner's agreement calls for transmission owners to provide short-term emergency ratings, which can be 10 to 15 percent higher than the normal ratings. Our analysis also shows that between $60 and $70 million of potential savings in congestion costs in 2017 and 2018 could have been achieved by ensuring that all transmission owners provide short-term emergency ratings that can be used by MISO as appropriate.

We recommend that MISO work with transmission owners to ensure more complete and timely use of both temperature-adjusted ratings (or use of dynamic factors such as conductor temperature, actual ground clearance, and actual and forecasted weather) and short-term emergency ratings. Additionally, we recommend that MISO work with its transmission owners to establish a consistent rating methodology to communicate an expectation that emergency ratings should be based on short-term temperature-adjusted ratings.

Status: Four transmission owners are currently providing temperature-adjusted ratings. We analyzed the dynamic ratings provided by two of these transmission owners and found that they are achieving substantial savings. We have worked with MISO to review the analysis and estimated benefits. This included gathering additional information that we have incorporated into this year's analysis. Nonetheless, although MISO has an interface for transmission owners to submit dynamic ratings, it continues to not be widely used.

MISO has aligned this recommendation with a Roadmap project called "Application of Dynamic and Predictive Ratings" that was classified as a low priority and it will not likely be pursuing this project in the next few years. However, this project includes more difficult elements that require software changes that are needed in response to this recommendation.

Next Steps: MISO should decouple this recommendation from the Roadmap Item # 54. We intend to work with MISO and the transmission owners to understand their concerns in providing temperature-adjusted ratings and emergency ratings so these concerns can be addressed.

To the extent that the transmission owners lack the incentive to provide dynamic ratings, we recommend MISO consider allocating a portion or all of the congestion surpluses (and shortfalls) to transmission owners that adjust their ratings.

### 2012-5: Introduce a virtual spread product

More than 70 percent of price-insensitive virtual bid and offer volumes (and 25 percent of all volumes) in 2018 were "matched" transactions. To the extent that the matched transactions are attempting to arbitrage congestion-related price differences, a virtual product to allow participants to do this price sensitively 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 because price-insensitive transactions can be highly unprofitable for the participant. They can also produce excess day-ahead congestion that can cause inefficient resource commitments.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. MISO originally agreed with this recommendation and the proposed resolution, but in 2018 MISO indicated that technical feasibility was a concern under the current systems. MISO indicated that the recommendation would be considered further after implementation of the Market Systems Enhancement. Hence, this recommendation is included in MISO's Roadmap as a Parking Lot item.

Next Steps: The IMM agrees with MISO's decisions to consider this recommendation further upon completion of the Market System Enhancement.

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

As noted in prior years, the integration of MISO South has increased the frequency of TLRs called by TVA. Substantial benefits for MISO could be achieved by developing a joint operating agreement that would allow MISO's day-ahead scheduled flows to be considered firm in the relief calculations. In addition, the TLR process could be replaced with a coordination process that would allow MISO and TVA to procure economic relief from each other.

Status: In the last few years, MISO has met with TVA a number of times to resolve specific transmission coordination and TLR issues. MISO has also proposed a JOA that would allow MISO and TVA to provide economic redispatch under certain circumstances, but no agreement was reached. However, significant and harmful TLRs continued in 2017 and early 2018. In

2018, MISO and TVA held additional meetings and agreed on an outline of potential improvements to coordination and operations as well as potential elements of a JOA that would include economic redispatch as an alternative to TLRs as well as further efforts to reduce the impacts of TLRs. In late 2018, MISO indicated that these discussions would likely continue into late 2019.

Next Steps: We continue to monitor for and evaluate the negative impacts on MISO's markets and customers caused by TLRs, including when TLRs are called on flowgates as proxies for lower-voltage constraints where MISO has little ability to provide cost-effective relief and where local actions (redispatch and reconfiguration) are likely far more effective. MISO should continue to attempt to negotiate a JOA that will allow economic coordination and redispatch to efficiently manage congestion on the MISO and TVA systems (rather than relying on the TLR process).

### 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 market-to-market 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.* Over the past six years, MISO focused only on the PJM interface in discussing this issue with its stakeholders. For the PJM interface, MISO ultimately decided to implement PJM's common interface, but our evaluation of the common interface in this report demonstrates that this was a mistake. We encourage MISO to begin a process of transitioning to a more efficient solution.

MISO has indicated agreement with this recommendation but has not begun work to address the pricing issues at all of MISO's other interfaces. Therefore, 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: Develop the workplan necessary to modify its interface prices as part of its Market Systems Enhancement.

## D. 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 addressed by the operating reserve requirements, MISO may take out-of-market actions to commit resources that are not economic at prevailing prices and, therefore, 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 these needs efficiently and allow the market prices to reflect the costs. The recommendations in this section are generally intended to improve this consistency between market requirements and operating requirements. This section also recommends changes in guarantee payments designed to improve participants' incentives.

### 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 as well as pay for the deployment of the reserves.

The deployment cost would be equal to the quantity of the reserves deployed times the shadow price of the RDT (which would generally be $500 per MWh when the reserves are deployed and the RDT substantially exceed its limit). Hence, if the flows rise to 3,500 MW after a contingency, the joint parties would receive 500 MW times $500 per MWh. 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 feasibly deployed given the flows that the deployment would cause on the joint parties' transmission systems.

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

### 2014-2 and 2016-4: Introduce a 30-minute reserve product to reflect VLR requirements and other local reliability needs

MISO has been incurring substantial RSG costs to satisfy VLR requirements and to manage flows on the RDT. MISO incurs these costs to prepare the area to withstand the largest contingencies. To address these needs, we recommended that MISO create a 30-minute reserve product in these areas so that these requirements can be priced and procured through MISO's markets (rather than through out-of-market commitments that result in uplift costs). This would be beneficial because it would provide market signals to build fast-start units or other resources that can satisfy the VLR or RDT needs at a lower cost (because they can satisfy the requirements while offline).

Status: This recommendation was originally proposed in our *2014 State of the Market Report*. MISO initially classified this recommendation as a high priority in the Roadmap process and assigned a forecasted implementation time in the second quarter of 2019. Subsequently, MISO merged this recommendation with another existing Roadmap project, *Short Term Capacity Pricing and Reliability Requirements*, which is intended to create a 30-minute reserve product to address both of these recommendations. In 2018, MISO made substantial progress in the design of this product. This project is currently planned for implementation in the first quarter of 2021.

Next Steps: Given the benefits of this recommendation, we support MISO moving as expeditiously as possible to implement this product. Hence, MISO should make avoiding slippage in the project schedule one of its highest priorities. This is currently scheduled for implementation in the fourth quarter of 2021.

## E. 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 as necessary. Each of these actions can substantially affect market outcomes.

One of the principal challenges to achieving efficient real-time outcomes is the five-minute time horizon of the real-time market. When the needs of the system require that resources ramp up or down rapidly, substantial costs can be incurred and real-time prices can become highly volatile to reflect these costs. These ramp demands have caused MISO's real-time energy prices to be more volatile than any of the other RTOs in the Eastern Interconnect. These ramp demands can be satisfied at a much lower cost if they are anticipated and if the dispatch of resources is modified to account for them over a timeframe longer than five minutes, or if the system holds low-cost ramp capability that can be utilized when unexpected ramp demands arise. The following five recommendations seek to improve MISO's real-time market processes.

### 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 generation emergencies, primarily at the regional level. Based on our review of these events, which is provided in Section III, we find that MISO's emergency declarations and actions were 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). In some cases, emergency events were not declared after a capacity deficiency had been forecasted or actually occurred. In other cases, emergencies have been declared when it is unclear in retrospect that an emergency declaration was needed to prevent a capacity deficiency.

Hence, we recommend that MISO evaluate its operating procedures, tools and criteria for declaring emergencies. This should include clarifying the criteria for declaring differing levels of emergencies, both regionally and for the entire footprint. Additionally, factors that contributed to the operator decisions should be well-logged.

Status: This is a new recommendation.

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

Operator decisions in all the MISO functions, including the day-ahead and real-time markets, can have very significant impacts on both market outcomes and reliability. While automated tools and models support most of the market operation, it is still necessary for operators to make decisions and adjustments to model inputs and results.

Although it is necessary and beneficial for operators to have the authority 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 evaluation and understanding. 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 forecasted load with the "load-offset" parameter, which are made to account for a myriad of real-time supply and demand factors that cause the dispatch model inputs to be inaccurate.
- Adjustments to TCDCs that are warranted to manage transmission constraints under changing conditions.
- Limit Control changes that alter the real-time limits for transmission constraints.
- Requests for market-to-market 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 settlement changes tend to be completely and accurately 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, many other actions listed above are logged in a narrative field that is inconsistently populated and difficult to use for evaluation purposes.

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. In particular, the transition to the Market Systems Enhancement could include enhancements to the logging tools to enable the improved logging.

Status: MISO has indicated agreement with this recommendation. In recent months, MISO and IMM staff have worked to identify specific potential improvements in the logging.

Next Steps: MISO and IMM staff will continue to work on identifying additional logging needs. Some improvements are planned for implementation as early as the fourth quarter of 2019. Additional logging improvements will be implemented with the Market Systems Enhancements.

### 2017-5: Evaluate the feasibility of implementing a 15-minute Day-Ahead Market under the Market System Enhancement

Currently the MISO day-ahead market is hourly and the real-time dispatch is conducted on a 5-minute basis. When the MISO market was initiated, the overall day-ahead market software performance and timeline did not permit more resolution. However, the hourly granularity creates significant operational drawbacks. By producing hourly schedules based on 60 minutes of ramp capability and hourly load forecasts, the day-ahead schedules cannot track the expected changes in real-time system needs, particularly during ramping periods. It also regularly results in generator schedule changes from hour to hour that are not feasible, which results in substantial make-whole payments.

More granular day-ahead market schedules would lower these uplift costs and better prepare the system to respond to the real-time needs. Therefore, as MISO proceeds with the Market Systems Enhancement effort, we recommend that it evaluate the feasibility of solving the day-ahead market with 15-minute scheduling intervals. With advances in computing power, this is likely feasible and cost-effective.

Status: MISO indicated agreement with this recommendation. MISO has included evaluation of an intra-hour day-ahead market in its draft MSE Primary Business Requirements.

Next Steps: MISO plans to finalize business requirements in partnership with MISO's vendor and consortium partners as part of the MSE program. MISO will update the MSE Primary Business Requirements in 2019.

### 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 2017 and 2018 indicates that the commitment recommendations are not accurate – 60 and 70 percent, respectively, of the LAC-recommended resource commitments are ultimately uneconomic to commit at real-time prices. We also found that operators only adhered to 37 percent of the LAC recommendations in 2018, which may be attributable to the inaccuracy of the recommendations. In 2016, one significant source of potential error was identified related to wind output assumptions and MISO resolved this issue. However, other potential issues will also need to be addressed to facilitate accurate LAC results. Hence, 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 2017, MISO addressed the IMM concerns regarding inaccurate wind assumptions in the LAC. In 2018, MISO implemented tools that support the review of LAC recommendations by the operators, but additional progress is needed to improve the accuracy of the LAC recommendations.

Next Steps: We recommend that MISO continue to work with the IMM to identify potential improvements to the LAC inputs or model to improve its accuracy. Once it is performing sufficiently well, we recommend improvements to MISO's procedures to increase adherence to the LAC recommendations.

### 2016-8: Validate wind resources' forecasts and use results to correct dispatch instructions

MISO's Tariff requires that a market participant's offers reflect the known physical capabilities and characteristics of its resources, including forecast maximum limits for wind resources that are DIRs. Other than ensuring that forecasts are timely, MISO does not validate the accuracy of wind suppliers' forecasts used to develop dispatch instructions for the DIRs. In 2016 and 2017, certain suppliers' wind forecasts were consistently biased, and many were consistently over-forecasted by more than 10 percent. Because the MISO dispatch uses these forecasts as the dispatch maximum, the lack of validation subjects the MISO energy dispatch to chronic shortfalls related to the over-forecasting. Additionally, over-forecasting can lead to inaccurate assumed system flows that result in inefficient congestion management.

We recommend that MISO develop appropriate operating procedures, including any necessary Tariff provisions to implement performance standards, in order to validate market participant forecasts. Real-time utilization of the most accurate forecasts will produce more appropriate dispatch instructions for dispatchable wind resources even when a participant's forecast is chronically inaccurate.

Status: While MISO agrees with the issue identified in this recommendation, MISO believes the Tariff revisions it filed on uninstructed deviations and DAMAP will significantly lessen the need for this recommendation. These Tariff revisions were approved in January 2019 and are to be implemented in May 2019. Since implementation, there are 16 units that continue to submit their own five-minute forecasts. All other units have moved to the MISO-generated forecasts. MISO continues to monitor the effectiveness of the uninstructed deviation changes and will utilize its available tools and information to periodically evaluate the accuracy of the remaining participant-generated forecasts.

Next Steps: MISO indicates that if reliability and/or inefficiency concerns remain after the implementation of the new settlement rules, it would support revisiting this recommendation. In particular, MISO is considering system changes that would replace a market participant forecast with the MISO-generated forecast when an erroneous forecast is identified.

### 2012-16: Re-order MISO's emergency procedures to utilize demand response efficiently

As noted above, as the capacity surplus falls in MISO, the peak needs of the system will increasingly be satisfied by interruptible load, behind the meter generation, or other forms of demand response. Unfortunately, these demand response resources cannot be curtailed by MISO before MISO has invoked nearly all other emergency actions, some of which are very costly and adversely impact the market. Hence, we reiterate this recommendation to modify the emergency procedures to allow MISO to utilize these resources in a more efficient manner. On September 15, 2018, for example, MISO experienced emergency conditions in the South. Very little demand response was available due in part to the ordering of the emergency procedures.

Status: This recommendation has been in the evaluation phase for the past five years and a further update was planned for the end of 2017, but this was not provided to the IMM. Little progress has been made to date and we are not aware of a substantive evaluation that has been performed. MISO recently filed changes that allow it to schedule LMRs in advance of calling an emergency, but the LMRs are not obligated to curtail unless MISO ultimately declares the highest level of emergency. This is an improvement, but it would still be beneficial to allow MISO to utilize demand response at lower emergency levels.

Next Steps: In its 2018 response, MISO indicated agreement to continue to evaluate this recommendation with the Resource Availability and Need work that began in 2017. We support this continued evaluation.

## F. Resource Adequacy

Reasonable resource adequacy requirements and a well-functioning capacity auction are intended to provide economic signals, together with MISO's energy and ancillary services markets, to facilitate efficient investment and retirement decisions. These economic signals will be increasingly important as planning reserve margins in MISO fall because of low prevailing energy prices, which will increase retirements of uneconomic units.

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 that are necessary to maintain reliability.

### 2018-5: Improve capacity accreditation by accounting for unforced and unreported outages and derates 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.[45] 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.

Therefore, we recommend MISO make improvements to its accreditation methodology used to estimate UCAP levels (i.e., the UCAP derate ratio applied to a resource to translate its ICAP

45 An exception to this exists for Load-Modifying Resources that receive additional capacity credit associated with the PRMR value and transmission losses. A second exception to this is for wind resources whose accreditation is based on their history of delivered energy rather than forced outages or derates.

level to a UCAP level). In particular, we recommend that MISO account for unforced and unreported outages and derates. These outages and derates have comparable effects on MISO's reliability as forced outages because they reduce the available supply in an unplanned manner.

FERC approved MISO's January 2019 Tariff filing that reduces the accreditation of resources taking short-notice outages during emergency conditions.[46] This is not likely to significantly affect the resources' accreditation, but it is a slight improvement. We recommend a more complete solution that would:

a) Expand this improvement to include all unforced and unreported outages and derates; and

b) Calculate the accreditation based on outages and derates that occur during the tightest supply conditions.

These changes would result in sizable accreditation improvements and eliminate the current incentive for suppliers to not report their outages and derates. Adopting this accreditation reform would better represent the reliability value that resources provide to MISO (in periods when the resources are needed) and can be easily adapted to a seasonal capacity accreditation construct.

Status: This is a new recommendation.

### 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 that are qualified through Generator Verification Tested Capacity (GVTC) tests currently deduct both station service loads (associated with the power generation equipment) and process loads (typically industrial loads consisting of combinations of heat and power) from their installed capacity (ICAP). Unlike station service loads, the process loads continue when the power generation equipment is out of service. Therefore, this load must be served along with MISO's other firm load, which should be recognized in the capacity requirements.

2. As a general principle, the planning assumptions should match real operations to the maximum extent possible. In calculating the demand for capacity, MISO implicitly assumes in its planning models that generation is fully available except when it experiences forced outages. However, this is not consistent with reality because substantial quantities of unforced outages and derates do occur during peak load conditions. This results in understated planning reserve requirements. We recommend that MISO review these assumptions.

46 See "Order Accepting Tariff Revisions, Subject to Condition," issued March 29, 2019, in Docket No. ER19-915-000.

3. We have identified a number of areas where erroneous data has been submitted by suppliers, resulting in sizable capacity accreditation inaccuracies. These errors have included: temperature and humidity corrections to GVTC test data, GVTC adjustments for process loads, especially from Combined Heat and Power (CHP) facilities, and simultaneous capabilities of interdependent power generation equipment during MISO system peak conditions. We recommend that MISO validate and verify such data when submitted by suppliers to qualify and accredit planning resources.

Status: This is a new recommendation.

### 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 has implemented its deliverability requirements in a manner that is not comparable for the NRIS and ERIS resources:

- The entire ICAP level of the NRIS resources must be deliverable, but
- ERIS resources need only secure firm transmission for the UCAP level of their resources, which can be 5 to 10 percent less than the ICAP level.

The requirements imposed by MISO on ERIS resources is not consistent with the intent of the Tariff. We recommend that MISO determine deliverability for all resources based on the entire ICAP of applicable planning resources (whether they are NRIS or ERIS resources). This will ensure consistency with the planning studies, which assume that resources will perform up to their ICAP level when they are available. This will also ensure consistency with the performance requirement of the Tariff section 69A.5 with the ICAP must-offer requirement. By making this change, ERIS resources would be required to procure firm transmission service in the amount of their ICAP level.

This may not be appropriate for intermittent resources because these resources cannot qualify to provide capacity at levels approaching their ICAP level. Therefore, it is likely the firm transmission service requirement would be set more appropriately at the upper end of the distribution of expected hourly output for wind resources, rather than their ICAP levels.

Status: This recommendation is currently under discussion with Stakeholders in the Resource Adequacy Subcommittee. MISO is planning to address it prior to the 2020/2021 PRA.

Next Steps: To develop revised qualification provisions and implement them by the end of December 2019. Treatment of intermittent resources needs to be developed through the stakeholder process.

### 2017-7: Establish PRA capacity credits for emergency resources that better reflect their expected availability and deployment performance

Generating resources are subject to obligations that help ensure that they will be available to MISO when needed, including the requirement to offer in the day-ahead market. Emergency-only resources, including LMRs and emergency-only resources, can sell capacity and are only required to deploy during emergencies when instructed by MISO. If they are not available to mitigate capacity shortages that usually occur early in the emergency events, then they are not providing the reliability value assumed in the planning studies 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 an emergency. Operators typically do not see and declare emergency events more than a few hours in advance of the shortage because they are often caused by unexpected contingencies or unexpected changes in wind output or load. Hence, LMRs and other emergency resources with long notification times would provide little value in most emergencies. This report confirms that this was the case in the last four emergencies that caused MISO to schedule LMR resources. This is not a problem for conventional resources with long notification or start times because an emergency does not have to be declared to commit these resources.

Therefore, we recommend that MISO develop a reasonable methodology for quantifying the capacity credit for emergency-only resources in the PRA. Such a methodology should consider factors that reduce the expected availability of resources, including the resources' seasonal availability, the time to deployment (notification plus start-up time/shut-down time), the variation in available curtailment quantity, and historical performance. The objective of these changes should be to qualify emergency-only resources at levels that would accurately reflect their expected availability during emergency conditions. This is comparable in principle to MISO's UCAP methodology for all other resources.

<u>Status</u>: This recommendation is aligned with the MISO's RAN Initiative and should be considered as part of the Phase 3 changes.

<u>Next Steps</u>: Complete the evaluation of this recommendation as MISO moves to Phase 3 of the RAN. MISO has begun these discussions in the Resource Adequacy Subcommittee, with a potential filing in 2020.

### 2016-9: Improve the qualification of planning resources and treatment of unavailable resources

Resources with no reasonable expectation of being available during system peak conditions should not qualify as planning resources, since this is fundamentally inconsistent with MISO's planning studies and requirements. Current market rules and Tariff provisions impose no requirement that market participants with inoperable units downgrade their operating status.

Resources on extended forced or planned outages that occurred after performing their GVTC test often qualify as planning resources even though they cannot be restored to service prior to the end of the system peak season. One resource in 2019, for example, will be on an approved planned outage for the entire planning year and nevertheless qualified to sell its capacity in the 2019/2020 PRA. In some cases, the asset owners have decided to not repair a resource on forced outage but can still sell it in the PRA. This clearly conflicts with the LOLE that assumes that market participants do not take planned outages when MISO is in peak load conditions. Not only do the current rules allow such resources to be offered, but the supplier potentially would be subject to physical withholding mitigation measures under the current Tariff if they do not offer the resources.

If inoperable units were required to enter a suspension status and ultimately to be retired, their interconnection service would be terminated, which potentially benefits the market because others can seek the service. Allowing unavailable resources to retain interconnection service indefinitely can present an unjustified barrier to entry for new suppliers. Maintaining the interconnection service is only justified if the participant is taking steps to restore the units to operation.

Therefore, we recommend that MISO require unavailable resources to be suspended and not qualified to sell capacity if they will not be operable during the peak season of the upcoming planning year.

<u>Status:</u> This recommendation is aligned with MISO's RAN Initiative. MISO is evaluating capacity accreditation with stakeholders, including the qualification and accreditation of resources with long-term outages, but MISO has not yet developed any proposals to address these concerns.

<u>Next Steps</u>: Work with stakeholders to develop provisions that will: a) limit inoperable units from holding interconnection service indefinitely, and b) as part of RAN, prevent resources with no reasonable expectation of being available during system peak conditions from qualifying as planning resources. MISO has begun these discussions in the Resource Adequacy Subcommittee, with a potential filing in 2020.

### 2015-5: Implement firm capacity delivery procedures with PJM

In June 2016, approximately 2 GW of capacity in MISO began pseudo-tying to PJM because it was sold in the PJM capacity market. In June 2017, additional resources began selling capacity to PJM and also pseudo-tied to PJM. Under its Capacity Performance construct, PJM completed its five-year transition period and now requires external resources to pseudo-tie to PJM, beginning with the Base Residual Auction in May 2017 (for the 2020/2021 planning year). While pseudo-tying may appear to achieve better comparability between PJM's external and internal capacity resources, it will impose substantial costs on the joint region by reducing dispatch efficiency and reliability. Additionally, the reduced dispatch efficiency will impose substantial potential cost exposure on both RTOs as the number of market-to-market constraints has continued and will continue to increase substantially.

We have developed proposed "Capacity Delivery Procedures" that would facilitate the delivery of MISO capacity to PJM without incurring the adverse effects of pseudo-tying the resources. We recommend that MISO work with PJM to develop these procedures, or similar procedures, to serve as an alternative to pseudo-tying MISO's resources to PJM. In nearly all respects, these provisions can be designed to impose requirements on capacity resources in MISO that are comparable to PJM's internal capacity resources without compromising dispatch efficiency or degrading local reliability. In fact, these provisions would increase PJM's access to the external capacity and make its delivery to PJM more reliable.

<u>Status:</u> MISO previously engaged PJM in a series of discussions and proposed a variant of Capacity Delivery Procedures to the MISO-PJM Joint and Common Market Initiative, but PJM indicated it cannot support it. This topic is not aligned with the MISO Roadmap Project and is currently in the "Externally Dependent" status.

Therefore, we filed a 206 complaint against PJM to eliminate the pseudo-tying requirement and replace it with a reasonable alternative, which could be the Capacity Delivery Procedures. FERC has taken no action on the 206 Complaint, but both RTOs have made tariff changes to limit the harm from pseudo-tied generation. However, we believe that the changes proposed by the RTOs will unreasonably restrict capacity trading.

<u>Next Steps</u>: The next steps on this recommendation will likely depend on FERC's Order on our Section 206 complaint. FERC has not yet issued a response to the complaint other than posting a notice that the complaint was filed.

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

MISO employs a relatively simple representation of transmission limits in the PRA, generally 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 as an additional constraint. All other constraints are evaluated through a simultaneous feasibility analysis that may cause MISO to re-run the PRA with modified import or export limits for one or more zones. 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 as needed 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.

<u>Status:</u> This recommendation was partially addressed through the recently accepted Tariff changes that establish External Resource Zones as neighboring balancing areas with their loadings on the RDT consistent with how it is modeled in the day-ahead and real-time markets. A similar approach could be taken to represent how all internal and external zones affect flows on key transmission constraints. This recommendation is not aligned with the MISO Roadmap and MISO indicates it is inactive. MISO intends to prioritize this work after the conclusion of discussions around a seasonal Planning Resource Auction, which are currently ongoing.

<u>Next Steps</u>: 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;
- 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;
- The qualification of resources with extended outages can better match their availability; and
- The duration of SSR contracts can be matched with planning seasons, which removes a barrier for SSR Units to serve as Planning Resources.

<u>Status:</u> MISO had originally proposed a two-season proposal. Use of two seasons does not capture the opportunity for savings that could be achieved by scheduling efficient economic

outages during the shoulder months and only reduces the benefits of a seasonal structure. This recommendation is aligned with the MISO's RAN Initiative and is being considered as part of RAN Phase 3.

Next Steps: To capture the benefits described above, we recommend that MISO evaluate the costs and benefits of implementing four seasonal requirements. MISO has begun these discussions in the Resource Adequacy Subcommittee, with a potential filing in 2020.

### 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 reasonably 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 presently facing the decision to retire in response to the market conditions driven by historically low natural gas prices.

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. If this recommendation is not addressed, the MISO markets will not facilitate efficient investment and retirement decisions by participants that sustain an adequate resource base. Instead, the region will have to rely primarily on the states requiring their regulated utilities to build new resources.

Understated capacity prices are a particular problem in Competitive Retail Areas (CRAs) where competitive suppliers rely on the market to retain adequate resources to ensure reliability. In 2016, MISO developed a proposal to improve the capacity pricing in CRAs that FERC ultimately rejected. We offered an alternative proposal that would have utilized a sloped demand curve to establish prices for competitive suppliers and loads. If a sloped demand curve cannot be implemented for all participants in the PRA, we recommend MISO implement one for the competitive loads and suppliers.

Status: MISO is not in agreement on this issue, particularly for non-retail choice areas, because it lacks support among the states. This recommendation is not aligned with the MISO Roadmap and MISO indicates it is inactive.

Next Steps: MISO should continue to work with its stakeholders and the Organization of MISO States (OMS) to move toward a consensus regarding the objective of facilitating efficient investment through the resource adequacy construct. The IMM will support this process by continuing to highlight the benefits of MISO establishing efficient capacity price signals, which include lowering the costs of satisfying the planning reserve requirements for both regulated and unregulated participants alike.

If a consensus cannot be achieved for improving the representation of demand in the overall market, we recommend that MISO implement capacity market reforms that would at least establish efficient prices for competitive suppliers and competitive load.

### *Recommendations Addressed by MISO*

In addition to the progress made on a some of recommendations discussed above, MISO addressed several past recommendations by implementing changes to its market software, operating procedures, or Tariff provisions in 2018 and early 2019. These recommendations are discussed below, along with unresolved recommendations that are not included in this year's report.

#### 2016-2: Improve procedures for identifying, testing, and transferring control of M2M flowgates

The procedures for identifying, testing, activating, and transferring control (when warranted) of M2M constraints are all critical to successful and efficient coordination of congestion management. Some elements in these processes are not highly automated. In 2017, we identified significant congestion on constraints that were not established as M2M constraints even though they appeared to qualify under the M2M tests. Our analysis indicated that in 2017, $243 million of congestion costs could have been more effectively managed if M2M coordination testing and activation procedures were more complete and timelier. Most of this congestion occurred on more than 160 constraints that would likely have passed the market-to-market tests, but for which no test was requested by MISO. To address these issues, we recommended automation and other improvements to the M2M processes.

Status and Resolution: In 2018, MISO implemented a tool that identifies constraints that should be tested for M2M coordination. This tool is in use daily on a production basis. Our review and analysis indicate this tool has proven useful in detecting constraints that should be tested and coordinated under the JOA, and substantially mitigated these concerns.

#### 2016-7: Improve forecasting incentives for wind resources by modifying deviation thresholds and settlement rules

Dispatchable wind resources in MISO have a strong incentive to over-forecast their output in real time. Under the current rules for all MISO Resources, Excessive Energy is paid the lower of LMP or the Resource offer. For most conventional resources this is a reasonable outcome and provides reasonable incentives. For wind resources, however, their offers often reflect a Production Tax Credit payment opportunity cost, so their offer prices are often in the range of negative $30 per MWh. Therefore, the Excessive Energy settlement for wind resources is far more punitive than the Deficient Energy settlement rules. Hence, we recommended MISO make the following two changes to improve the incentives of the wind resources:

- Consider a modified Excessive Energy threshold for wind resources that would allow these resources more latitude to exceed their dispatch levels (i.e., their forecasted output) when it will not cause congestion;
- Modify the Excessive Energy settlement to help balance the Excessive and Deficient Energy settlements that wind resources face associated with forecast errors.

Status and Resolution: In 2018, MISO completed Tariff changes to its uninstructed deviation provisions. The MISO changes included substantially reducing the excess energy penalty on the wind resources. MISO filed this proposal in late 2018. It was approved in January 2019, and it was implemented in May 2019.

### 2017-3: Improve commitment classifications and implement a process to correct errors

Resource commitments are made by market participants and by MISO. The commitments made by MISO are generally made to satisfy its market-wide or subregional capacity needs, or to manage transmission constraints. When MISO makes a commitment, it assigns a classification code that determines whether the resource is eligible for RSG, how the RSG costs (if any) are allocated to MISO market participants (e.g., CMC, DDC, and Load Ratio) and whether RSG payments are subject to market power mitigation. Only payments for commitments identified as required to manage a transmission constraint or VLR requirements are subject to mitigation.

The IMM has observed that MISO operators sometimes misclassify commitments, most of which have been commitments of resources classified as capacity commitments that are later determined to have been needed to manage other transmission constraints. This misclassifying is harmful because commitment code assignments have significant implications for RSG allocations and market power mitigation. Hence, it is valuable for MISO to develop a robust process for reviewing and correcting commitment classifications as needed.

Status and Resolution: The IMM developed automated procedures to identify misclassified commitments, notify MISO, and recommend mitigation. These procedures were implemented in the first quarter of 2019. MISO plans to implement procedures to correct misclassifications for cost allocation purposes.

### 2016-5: Reform DAMAP and RTORSGP rules to improve performance incentives, and reduce gaming opportunities and unjustified costs

Our evaluation of DAMAP and RTORSGP reveals that significant amounts were paid to resources that were not performing well. These price volatility make-whole payments are intended to ensure that resources have incentives to be flexible and are not harmed financially when following MISO's dispatch instructions. Under the current payment formulas, however, some resources receive payments because they are running at an uneconomic dispatch level as a result of not following MISO's dispatch instructions. Suppliers should be accountable for poor generator performance, and these payments were not intended to hold suppliers harmless for poor performance. Because poor performance can increase such payments, the current rules may encourage manipulative strategies involving coordinating offer prices and deliberate poor performance. To address these concerns, we recommended that MISO incorporate a performance metric in the calculation of these make-whole payments that would reduce the payment by the amount that corresponds to resources' dispatch deviations.

Status and Resolution: In 2018, MISO developed proposed Tariff changes to reform the uninstructed deviations formula and the related rules for DAMAP and RTORSGP. MISO worked with participants and the IMM on reforms MISO filed this proposal in late 2018 and it was approved in January 2019. These changes were implemented in May 2019.

### 2012-12: Improve thresholds for uninstructed deviations

All RTOs have a tolerance band that defines how much a resource's output can vary from the RTO's dispatch instruction before the supplier is penalized for uninstructed deviations. MISO's tolerance band of eight percent of the dispatch instruction (which also requires the deviation occur in four consecutive intervals) is substantially more lenient than those of other RTOs, and it effectively increases as the dispatch instruction increases.[47] In fact, many resources can ignore MISO's dispatch instructions altogether and not be deemed to be deviating under this criteria. Additionally, as we discussed above, when units perform poorly but do not exceed the tolerance bands, they retain eligibility for PVMWP payments, which will hold them harmless for their poor performance and create adverse incentives.

To address these concerns, we recommended MISO adopt thresholds based on resources' ramp rates that effectively differentiate poor performance from acceptable performance. Resources that are deemed to be deviating under these criteria should incur uninstructed deviation penalties and costs, lose eligibility to supply ancillary services and the ramp product, and lose eligibility for PVMWP. This will improve suppliers' incentives to follow MISO's dispatch signals and will, in turn, improve reliability and lower overall system costs. Additionally, it would be advisable to remove the ramp and headroom on such units from the LAC in order to allow the LAC model to make better recommendations.

Status and Resolution: In 2018, MISO completed Tariff changes to its uninstructed deviation provisions. The proposed revisions include a mileage-based approach. MISO filed this proposal in late 2018, it was approved in January 2019, and implemented in May 2019.

47 This is because the threshold is a fixed percentage of the dispatch instruction. MISO's threshold also includes a minimum of six MW and a maximum of 30 MW.

### *Unresolved Recommendations Not Included in 2018 Report*

#### 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 boundaries that are unrelated to the transmission network.

Status: MISO has engaged its stakeholders in a discussion of the criteria for establishing zones based primarily on transmission constraints, but a proposal has not been finalized. MISO indicates work to address this recommendation is currently deferred. This topic is not aligned with the MISO Roadmap Project and is currently in an inactive status. We believe that this is a lower priority improvement than many of the other recommendations in this report, so we are not including it this year.