2017 State of the Market Report for the MISO Electricity Markets

Prepared By:

POTOMAC ECONOMICS

Independent Market Monitor
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
CC	Combined Cycle
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
CT	Combustion Turbine
CTS	Coordinated Transaction Scheduling
DAMAP	Day-Ahead Margin Assurance Payment
DDC	Day-Ahead Deviation and Headroom Charge
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 Regulatory Commission
FFE	Firm Flow Entitlement
FTR	Financial Transmission Rights
GSF	Generation Shift Factors
GW	Gigawatt (1 GW = 1,000 MW)
GWh	Gigawatt-hour
HDD	Heating Degree Day
HHI	Herfindahl-Hirschman Index
IESO	Ontario Independent Electricity System Operator
IMM	Independent Market Monitor
ISO-NE	ISO New England, Inc.
JCM	Joint and Common Market
JOA	Joint Operating Agreement
kWh	Kilowatt-hour
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 Transmission System Operator
MMBtu	Million British thermal units, a measure of energy content
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 Corporation
NSI	Net Scheduled Interchange
NYISO	New York Independent System Operator
ORCA	Operations Reliability Coordination Agreement
ORDC	Operating Reserve Demand Curve
PJM	PJM Interconnection, Inc.
PRA	Planning Resource Auction
PVMWP	Price Volatility Make Whole Payment
PY	Planning Year
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 Payment
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
VCA	Voluntary Capacity Auction
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 *2017 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 region 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 2017

The MISO energy and ancillary services markets generally performed competitively in 2017. The most notable factor affecting market outcomes in 2017 was the increase in natural gas prices from historically low levels in recent years. The 17 percent increase in natural gas prices from 2016 and increases in other fuel prices led to a 11 percent increase in energy prices throughout MISO, which averaged $29.46 per MWh in 2017.

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 2017. This indicates that the MISO markets were highly competitive in 2017.

- The "output gap" is a measure of potential economic withholding. It remained unchanged from 2016, averaging 0.11 percent of load, which is *de minimus*. Consequently, market power mitigation measures were applied infrequently.

Although system-wide energy prices rose slightly, prices often varied substantially throughout MISO, reflecting congestion on the MISO transmission network. The value of real-time congestion increased by 7.2 percent to $1.5 billion, driven in part by higher natural gas prices and in part by efficiency concerns. These concerns relate to the market-to-market coordination with PJM and SPP, the lack of coordination of outages that affect congestion, resources pseudo-tied to PJM, and transmission rating practices. To address these concerns, we recommend a number of improvements to lower the cost of managing congestion on MISO's system.

MISO implemented several market design changes in 2017 that were intended to improve the efficiency and competitiveness of the MISO markets.

- On May 1, MISO implemented ELMP Phase 2 that allows online resources with up to a 60-minute startup and notification time to be eligible to set real-time prices.
- On June 1, MISO adopted PJM's 10-point "common" interface definition to calculate congestion settlements for imports and exports.
- On July 1, MISO implemented emergency pricing construct changes that provide more accurate pricing during emergency events.
- On October 3, MISO and PJM implemented Coordinated Transaction Scheduling (CTS) to allow market participants to schedule economic transactions based on the difference between forecast interface prices.
- MISO filed for authority to define Dynamic Narrow Constrained Areas (DNCAs) consistent with our SOM Recommendation 2012-9. This was approved by FERC and became effective January 4, 2018.

Regrettably, the three most significant changes related to ELMP, interface pricing, and CTS are not performing well. The report includes a discussion of changes we recommend to address these performance issues.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

In 2017, MISO lost 3.8 GW of resources, of which a significant amount was gas-fired resources in MISO South and coal-fired resources in the Midwest. MISO added 1.2 GW of new resources. 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, however, our assessment indicates that the system's resources should be adequate for the summer of 2018 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. The most recent OMS-MISO survey revealed that the surplus capacity level fell from almost 4 GW to 600 MW in 2018. This reduction occurred despite a reduction in the peak load forecast of 1.5 GW and the addition of roughly 1,000 MW of additional demand response that cleared in the most recent planning resource auction. As we explain, 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 2017, and found:

- Net revenues continue to be substantially less than necessary for new investment to be profitable in any 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
- Net revenues fell at locations in MISO Central and North compared to last year and increased significantly at locations in MISO South because of congestion.

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 due to 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.[1] 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.

The design issues described below, along with modest changes in supply and demand, have resulted in volatile market outcomes over the past two years:

- In 2017/2018, decreased capacity requirements and an increase in the modeled transfer capability between subregions contributed to a MISO-wide clearing price of essentially zero ($1.50 per MW-day).
- In 2018/2019, 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 that was export-constrained.

The low clearing prices in the recent auctions and the price volatility more broadly is 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 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, including:

- Allowing units with Attachment Y retirement requests to participate in the PRA and have the ability to postpone or cancel the retirement if they clear in the auction.

[1] Hereinafter, "Tariff" will refer to MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

- Transitioning to a seasonal capacity market.
- Improving the modeling of transmission constraints in the PRA.
- Limiting emergency-only resources to participate in the capacity market if they are able to be available within a reasonable amount of time during an emergency.

Transmission Congestion

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources. The costs of these dispatch changes are congestion costs and 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 2017

The value of real-time congestion increased by 7.2 percent from last year to $1.5 billion. Natural gas prices increased in the first half of 2017, which tends to increase congestion costs since natural gas-fired units are generally dispatched to manage the power flows over binding constraints. Not all of the $1.5 billion in real-time congestion is collected by MISO through its markets, primarily because loop flows caused by others and flow entitlements granted to PJM, SPP, and TVA do not pay MISO for use of the network. Hence, day-ahead congestion costs totaled $743 million in 2017, up one 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 2017. This is good because under-funding FTRs degrades the value of the FTRs and ultimately, this harms transmission customers that 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 grew 24 percent in 2017 to $467 million, which is more than a quarter 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. Hence, we evaluate this process and recommend improvements in this report.

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. These issues include:

- *Market-to-Market Coordination.* The failure to define and coordinate congestion management on constraints through the market-to-market process. We identified more than 160 constraints in 2017 that were not defined as market-to-market constraints, generally because MISO did not ask for the constraints to be tested. The congestion on these constraints exceeded $240 million in 2017.
- *Outage Coordination.* Transmission and generation outages occurring simultaneously that affect the same constraint. Roughly $400 million – more than 30 percent of all of MISO's real-time congestion – occurred on constraints affected by multiple generation outages. This underscores in 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 -- 95 new market-to-market constraints in MISO have been defined because of the MISO units that have been pseudo-tied to PJM. In 2017, congestion costs on these constraints exceeded $155 million, roughly 70 percent 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 as much as $127 million in production costs in 2017 by using temperature-adjusted, short-term emergency ratings. This supports continued efforts with transmission owners to receive and use these ratings.

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 2017:

- The difference between day-ahead and real-time prices was 0.3 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 regions of MISO.

Virtual transactions provided essential liquidity and improved the convergence of day-ahead and real-time energy prices. Cleared virtual transactions rose 10 percent in 2017 to average almost 14 GW per hour. Our evaluation of virtual transaction revealed:

- More than 90 percent of the virtual trading is 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 continue 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 2017, as indicated above, rising 11 percent relative to 2016.

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 price formation because they jointly optimize operating reserves and energy in the real-time markets, and allow the demand curves for reserves to contribute to setting prices when the market cannot satisfy reserve requirements. However, we identify improvements in MISO's operating reserve demand curves that will allow the shortage pricing to be more efficient. We also show that by allowing offline resources to set prices in the ELMP model, MISO is artificially muting its shortage pricing. Hence, we recommend improvements to the reserve demand curves and recommend that MISO disable its offline resource pricing in ELMP.

ELMP's greatest virtue is its capability to allow online peaking resources and emergency supply (or DR) 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. It has raised real-time prices by an average of only $0.41 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 $1.80 per MWh. In high-load hours when reliance on peaking resources is relatively higher, these price effects are far higher, which provides much better incentives to schedule imports and exports efficiently and facilitate efficient generator commitments in the day-ahead market. We believe making these improvements should be a high priority because efficient real-time pricing is essential.

Real-Time Generator Performance

A substantial concern we evaluate is the poor performance of some of the generators in following MISO's dispatch instructions as. 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) in 2017 averaged more than 200 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 perceived by MISO's operators. To address these concerns, we have proposed:

- Better uninstructed deviation thresholds and modifications in the DAMAP formulas to improve incentives for generators to follow dispatch signals. MISO has worked with the IMM and its stakeholders to develop a proposal to address this recommendation and plans to file the proposal in the third quarter of 2018.
- Improved tools for operators to identify poor generator performance and State-Estimator model errors that are contributing to inefficient dispatch. In 2017, we developed an alert that is sent to MISO operators when significant sustained generator deviations occur.

These changes will improve generators' performance and result in lower DAMAP being paid to generators not following their dispatch instructions.

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 lead 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 can allow wind resources to earn more revenue by deliberately overforecasting their output than by forecasting accurately. The wind resources are only eligible for these DAMAP revenues because of the flaw in MISO's tariff which should be corrected with the introduction of five-minute settlements in the third quarter of 2018.

Hence, we are recommending 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. We are also recommending that MISO validate the forecasts in real time and address sustained errors when it produces its real-time dispatch.

Uplift Costs

Revenue Sufficiency Guarantee (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 13 percent to $5.4 million per month.
- Day-ahead RSG increased by 11 percent to $3.4 million per month. Half of these payments were associated with Voltage and Local Reliability (VLR) commitments in MISO South.

These increases were largely due to the 17 percent increase in natural gas prices in 2017, although RSG costs to manage the RDT increased sharply in 2017.

High outage rates combined with unseasonably warm temperatures in early April and late in September contributed to many out-of-market commitments in the South subregion to manage potential flows across the Regional Directional Transfer (RDT) constraint. These commitments were treated as capacity commitments even though they were committed to maintain enough online capacity in real time in the South to prevent exceeding the RDT limit after a major contingency. This is effectively a procurement of a 30-minute reserve requirement.

We continue to recommend that MISO develop a 30-minute subregional reserve product consistent with the operating requirements described above. MISO is working on such a product and is targeting implementation in late 2019. In the meantime, it filed Tariff changes to allow its Reserve Procurement Enhancement (RPE) to apply to the RDT. This would hold 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. Twelve resources in MISO pseudo-tied into PJM in 2016. 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 congestion on the constraints affected by these units has increased by more than 70 percent on a monthly average basis from before the pseudo-ties were implemented. Our analysis also shows that the dispatch of pseudo-tie resources has been much less efficient than if the units continued to be dispatched by MISO.

The effects of these pseudo-tied units have to be managed under the market-to-market (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 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 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. MISO's transmission reservation fees (charged to all CTS offers) result in average costs per cleared MWh ranging from roughly $20 per MWh on exports to almost $50 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 more than 11.5 GW of DR resources, which includes 4 GW of behind-the-meter generation. However, most of MISO's DR capability is in the form of interruptible load developed under regulated utility programs. More than 85 percent of MISO's DR resources are capacity resources or LMRs that can only be accessed after MISO has declared an emergency.

MISO has also been working with its Load Serving Entities to improve real-time information on the availability of LMRs. Although the information from many of the participants is not fully accurate, MISO's improved operational awareness from this process will improve its ability to maintain reliability. In addition to this improvement, we have recommended a number of other changes related to the integration of LMRs in the MISO markets. These recommendations include modifying the emergency procedures to utilize its DR capability more efficiently.

Finally, we evaluate the availability of DR and other emergency resources during the past two emergency events in which LMRs were called (April 4, 2017 and January 17, 2018). LMRs are only obligated to be available during the summer months and after an emergency event has been declared. Since they have notification times up to 12 hours, their accessibility depends on how far in advance MISO recognizes and declares the emergency. None of the DR was obligated to be available since they occurred outside the summer. Even if these resources were all offered as available to be scheduled, only 15 and 39 percent of all of MISO's emergency resources were available given the timing of the emergency declaration and the notification times of the resources. This raises concerns given MISO's increasing reliance on these units to satisfy its planning requirements. Hence, we are recommending that MISO revisit the rules it uses to qualify DR resources and other emergency resources to provide unforced capacity under Module E.

Table of Recommendations

Although the markets performed competitively in 2017, we make 29 recommendations in this report intended to further improve their performance. Seven of the recommendations are new this year, while 22 were recommended in prior reports. It is not unexpected that recommendations are carried over from year to year because many of our recommendations require software changes that can require years to implement. MISO addressed four of our recommendations in 2017 and early 2018, as discussed in Section X.F.

The table shows the recommendations organized by market area. They are numbered to indicate the year in they were introduced and the recommendation number in that year. We indicate whether each would provide high market benefits and whether it can be achieved in the short term. The table also notes the seven "Focus Areas" from MISO's market roadmap process.[2]

SOM Number	Focus Area	Recommendations	High Benefit	Fast Track
Energy Pricing and Transmission Congestion				
2017-1	1,3	Improve the market power mitigation rules		✓
2017-2	4	Remove transmission charges from CTS transactions	✓	✓
2016-3	2,7	Enhance authority to coordinate transmission and generation planned outages		
2016-2	3,4	Improve procedures for identifying, testing, and transferring control of M2M flowgates		✓
2016-1	1,3,7	Improve shortage pricing by adopting an improved contingency reserve demand curve that reflects the expected value of lost load	✓	✓
2015-2	2,3	Expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities	✓	
2015-1	3	Expand eligibility for online resources to set prices in ELMP and suspend pricing by offline resources	✓	✓
2014-3	2	Improve external congestion related to TLRs by developing a JOA with TVA		
2012-5	1,2	Introduce a virtual spread product		
2012-3	4	Remove external congestion from interface prices		

[2] 1. Enhance Unit Commitment and Economic Dispatch Processes;
2. Maximize Economic Utilization of Existing and Planned Transmission Infrastructure;
3. Improve Efficiency of Prices under All Operating Conditions;
4. Facilitate Efficient Transactions Across Seams with Neighboring Regions;
5. Streamline Market Administrative Processes that Reduce Transaction Costs;
6. Maximize Availability of Non-Confidential and Non-Competitive Market Information; and
7. Support Efficient Development of Resources Consistent with Long-term Reliability.

SOM Number	Focus Area	Recommendations	High Benefit	Fast Track
Operating Reserves and Guarantee Payments				
2017-3	3	Improve commitment classifications and implement a process to correct errors		
2016-5	1,5	Reform DAMAP and RTORSGP rules to improve performance incentives, and reduce gaming opportunities and unjustified costs	✓	✓
2016-4	1,3,7	Establish regional reserve requirements and cost allocation	✓	
2014-2	1,3,7	Introduce a 30-Minute reserve product to reflect VLR requirements and other local reliability needs	✓	
Dispatch Efficiency and Real-Time Market Operations				
2017-5	1.3	Assess the feasibility of implementing a 15-minute Day-Ahead Market under the Market System Enhancement	✓	
2017-4	1	Improve operator logging tools and processes related to operator decisions and actions		
2016-8	1,3	Validate wind resources' forecasts and use results to correct dispatch instructions		✓
2016-7	1,5	Improve forecasting incentives for wind resources by modifying deviation thresholds and settlement rules		
2016-6	1	Improve the accuracy of the LAC recommendations		✓
2012-16	1,3	Re-order MISO's emergency procedures to utilize demand response efficiently		✓
2012-12	1,5	Improve thresholds for uninstructed deviations	✓	✓
Resource Adequacy				
2017-7	7	Establish PRA capacity credits for emergency-only resources that better reflect their expected availability and deployment performance	✓	✓
2017-6	7	Require the ICAP of planning resources to be deliverable		✓
2016-9	7	Improve the qualification of planning resources and treatment of unavailable resources		✓
2015-6	2,7	Improve the modeling of transmission constraints in the PRA		
2015-5	7	Implement firm capacity delivery procedures with PJM	✓✓	
2014-6	2,7	Define local resource zones based on transmission constraints and local reliability requirements		
2014-5	7	Transition to seasonal capacity market procurements		
2010-14	7	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 16 states in the Midwest. The MISO markets include:

Day-ahead and real-time energy markets: These markets utilize the lowest-cost resources to satisfy the system's demands without overloading the transmission network. They provide economic signals to govern short and long-run decisions by participants.

Financial Transmission Rights (FTRs): Congestion revenues collected through the MISO markets fund FTRs. FTRs allow participants to hedge congestion costs by entitling holders to the congestion between locations in the day-ahead market.

Ancillary Services Markets (ASM): These products include operating reserves and regulation. The ancillary services and energy markets are jointly optimized to allocate resources efficiently. Co-optimization allows prices to fully reflect shortages of and tradeoffs between the products.

Capacity Market: The Planning Reserve Auction (PRA) was implemented in 2013. Because the demand in the PRA does not reflect the reliability value of capacity, this market cannot achieve the purpose of a capacity market – to facilitate efficient investment and retirement decisions.

Key changes or improvements implemented in 2017 included:

- On May 1, MISO implemented ELMP Phase 2 that allows online resources with up to a 60-minute startup and notification time to be eligible to set real-time prices.
- On June 1, MISO adopted PJM's 10-point "common" interface definition to calculate congestion settlements for imports and exports.
- In July, MISO filed for authority to define Dynamic Narrow Constrained Areas (DNCAs) consistent with our SOM Recommendation 2012-9. This was approved by FERC and became effective January 4, 2018.
- On October 3, MISO and PJM implemented Coordinated Transaction Scheduling (CTS) to allow market participants to schedule economic transactions based on the difference between forecast interface prices.

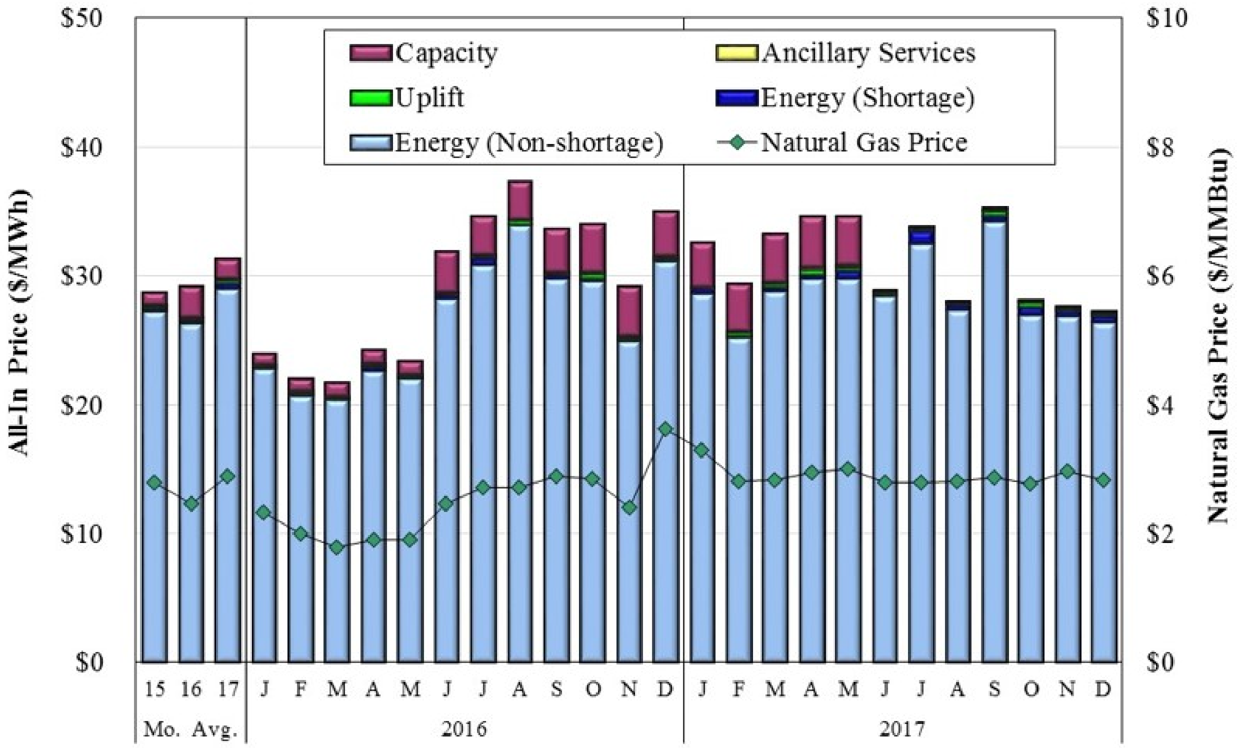
Regrettably, the three most significant changes related to ELMP, interface pricing, and CTS are not performing well. The report includes a discussion of changes we recommend to address these performance issues.

II. PRICE AND LOAD TRENDS

A. Market Prices in 2017

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 for any reserve product.

Figure 1: All-In Price of Electricity
2016–2017



The all-in price increased by seven percent in 2017 to an average of $31.35 per MWh because:

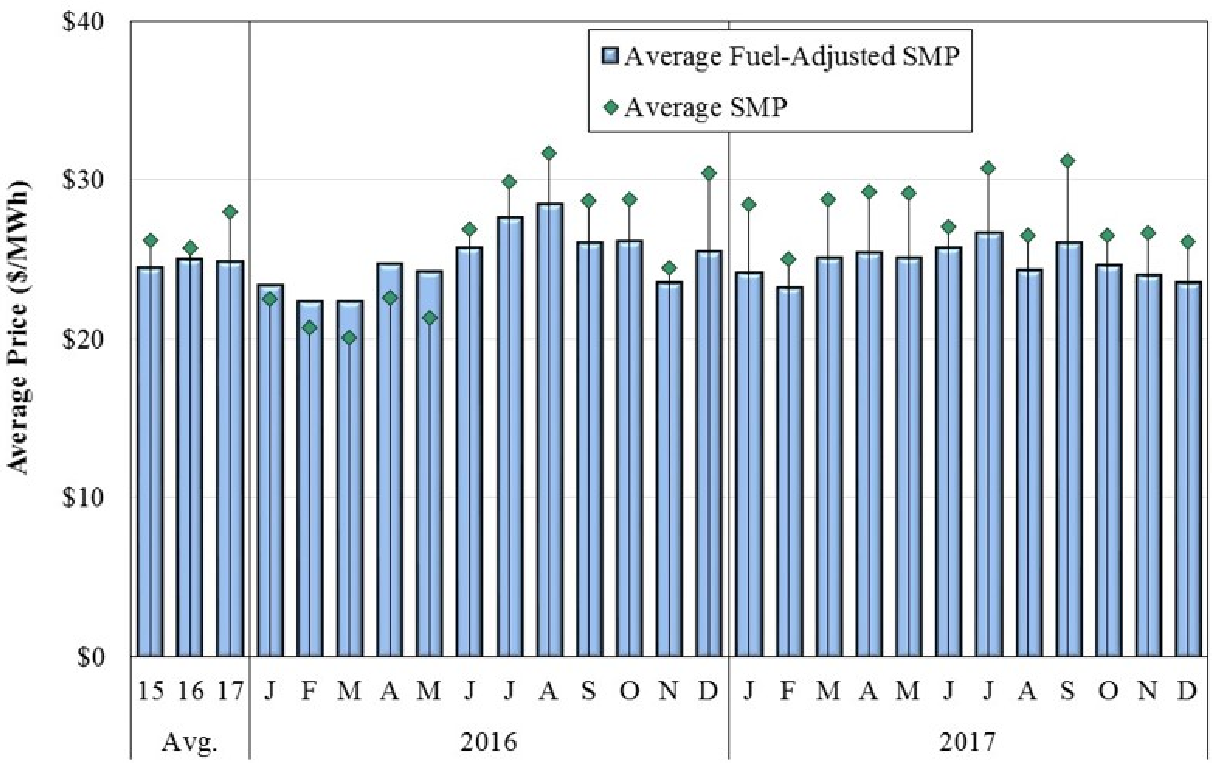
- Energy prices increased by 11 percent, largely attributable to a 17 percent increase in natural gas prices from the historically low 2016 levels.
- Energy shortage prices more than doubled over 2016 prices because of several operating reserve shortages, while non-shortage energy prices increased by 10 percent.
- The capacity component of the all-in price fell 37 percent because the 2017-2018 capacity auction cleared at $1.50 per MW-day, which is effectively zero. Capacity remains undervalued because of shortcomings in the PRA design, which we discuss later.
- The ancillary services uplift remained a very small portion of the all-in price, increasing by $0.02 per MWh to total $0.10 per MWh.

- Higher fuel prices in 2017 and more out-of-merit commitments made for the Regional Direction Transfer (RDT) constraint increased the uplift component of the all-in price by $0.05 to total $0.25 per MWh.[3]

As in prior years, the real-time energy component constituted most of the all-in price. Low natural gas and coal prices caused MISO's energy prices to remain at historically low levels. 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. However, energy prices rose faster than fuel prices in July and September, caused in both months by relatively high load levels and, in September, significant outages.

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.[4]

Figure 2: Fuel-Adjusted System Marginal Price
2016–2017



3 Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs, and Price Volatility Make Whole Payments (PVMWPs). PVMWPs are made to ensure resources are not harmed when following MISO's dispatch instructions.

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

The nominal SMP in 2017 increased by nine percent over 2016. In the first half of the year, the average SMP was 25 percent higher than in 2016 because gas prices were 43 percent higher than the historically low levels that prevailed in the prior year. Average gas prices were one percent lower in the second half of the year than in 2016, which contributed to a four percent decline in the SMP in that period.

Excluding the fuel price changes described above, we find that the fuel-adjusted SMP *decreased* by one percent. This reduction is generally attributable to mild summer weather and lower loads in 2017, particularly in August. The fuel-adjusted SMP was higher in September than August because unseasonably warm temperatures late in the month coupled with significant outages led to relatively high prices.

B. Fuel Prices and Energy Production

The resource mix and energy output were relatively stable from 2016 levels, although coal-fired capacity shares fell slightly as 2 GW retired and around 1 GW were repowered to natural gas. Table 1 below summarizes the share of capacity, energy output, and how frequently resources were marginal for system-wide prices and local prices by fuel type in 2016 and 2017.

Table 1: Capacity, Energy Output, and Price-Setting by Fuel Type
2016–2017

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2016	2017	2016	2017	2016	2017	2016	2017	2016	2017
Nuclear	12,432	12,420	9%	10%	16%	16%	0%	0%	0%	0%
Coal	53,471	50,843	41%	39%	46%	47%	56%	55%	85%	84%
Natural Gas	55,367	55,794	42%	43%	27%	23%	42%	44%	85%	85%
Oil	1,832	1,904	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,478	3,929	3%	3%	1%	1%	1%	0%	2%	1%
Wind	2,796	2,610	2%	2%	8%	8%	1%	0%	32%	30%
Other	2,080	2,273	2%	2%	2%	4%	0%	0%	3%	4%
Total	**131,456**	**129,773**								

Energy Output Shares. The lowest-cost resources (coal and nuclear) operated at the highest capacity factors and coal continued to produce the greatest share of energy . Natural gas-fired resources' share of output (23 percent) remained significantly lower than its share of capacity (43 percent) because a large portion of the gas-fired resources are peaking units that run infrequently.

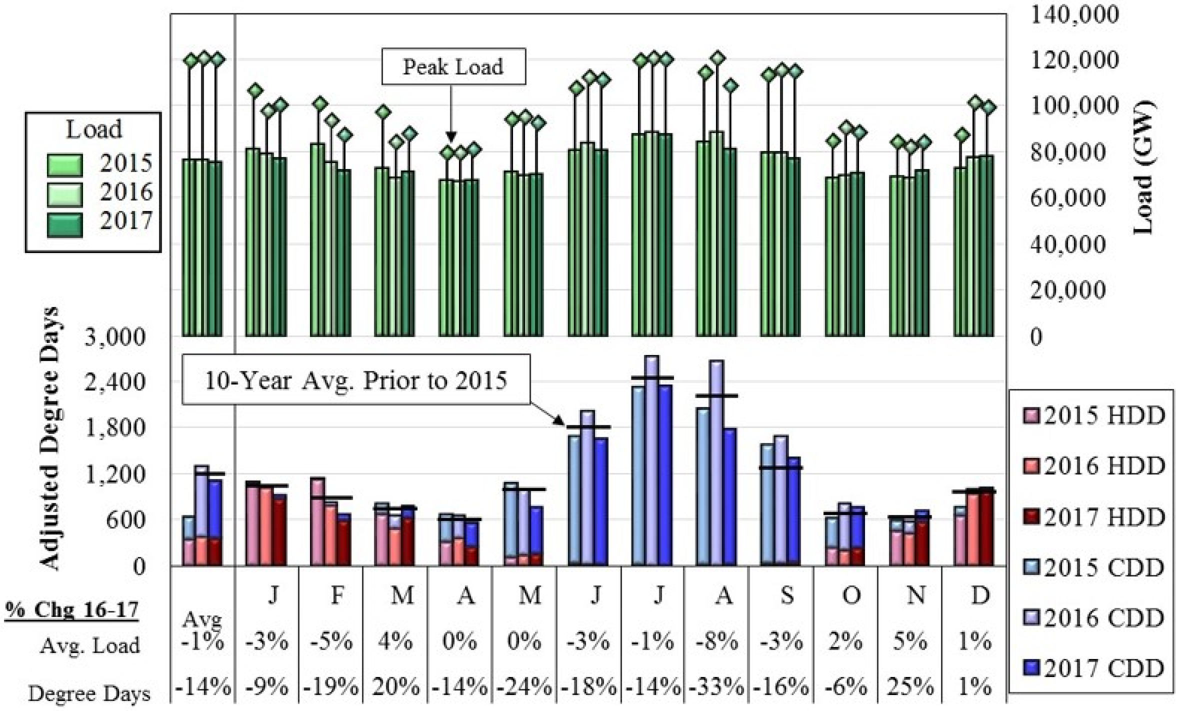
Price-Setting Shares. Although natural gas-fired units produce a modest share of the energy in MISO, they play a pivotal role in setting energy prices. Gas-fired units set the system-wide price in 44 percent of all intervals for the year, including almost all peak hours when prices are highest. In addition, 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 85 percent of intervals and why they are a key driver of energy prices. Coal-fired resources continued to set the system-wide price in more than half of intervals, including most off-peak hours.

Wind Resources. The capacity values in Table 1 are unforced capacity values so they are derated significantly from the installed capacity level to account for outages and intermittency. This derating has the largest effect on wind resources, which are derated by 86 percent, and they therefore only account for two percent of MISO's unforced capacity. However, their share of energy output is much larger at eight percent and, because wind units often cause congestion on lines exiting their locations, they set prices in their local areas 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 patterns. 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.[5]

Figure 3: Heating- and Cooling-Degree Days
2015–2017



5 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.

The total degree days fell 14 percent overall in 2017, as temperatures in the summer months were generally milder than in 2016 and winter temperatures early in the year were warmer than normal. However, the average annual load fell only one percent. Increases in heating degree days in March and November contributed to higher average load in those months, offsetting declines in load in other months.

MISO set its annual peak load of 120.6 GW on July 20, approximately the same as the 2016 peak load. Actual peak load was well below the forecasted peak of 125 GW from MISO's *2017 Summer Resource Assessment.*

D. Detailed Review of Emergency Events

In 2017, MISO experienced several weather-related events that impacted prices and load:

- During the winter, severe storms caused outages and higher congestion on a number of days. On February 7, tornadoes in MISO South led to multiple transmission outages and severe congestion. Prices at the Louisiana Hub exceeded $1,000 per MWh.
- Storms in early and late March led to multiple Severe Weather Alerts.
- On April 4, hot temperatures, high outages, and the loss of a large nuclear unit caused MISO to issue a Maximum Generation Event that we discuss in detail in this subsection.
- On June 11, MISO declared Severe Weather Alerts in the North as severe thunderstorms caused two islanding events.
- Later in June, Tropical Storm Cindy in the South and significant thunderstorms and potential tornadoes in the North led to Severe Weather Alerts on several days.
- On August 21, a solar eclipse that was followed by severe thunderstorms caused real-time load to come in below forecast by as much as 8 GW.
- In late August and early September, Hurricane Harvey caused extensive flooding in the South, leading to Conservative Operations in Eastern Texas and Western Louisiana.
- In late September, unseasonably warm temperatures throughout MISO, combined with high outage rates and a Transmission Line Loading Relief (TLR) called by TVA led to multiple Max Gen Alerts and one Event on September 22, which we discuss below.

Given the surplus supply MISO currently enjoys, generation emergencies are relatively infrequent, and are generally the result of a combination of severe weather and significant generator outages. These events are important to evaluate because they reveal how well the market performs under stress. Therefore, we discuss three significant events below that occurred between April 2017 and January 2018.

April 4, 2017: Emergency Pricing and LMR Deployment in MISO South

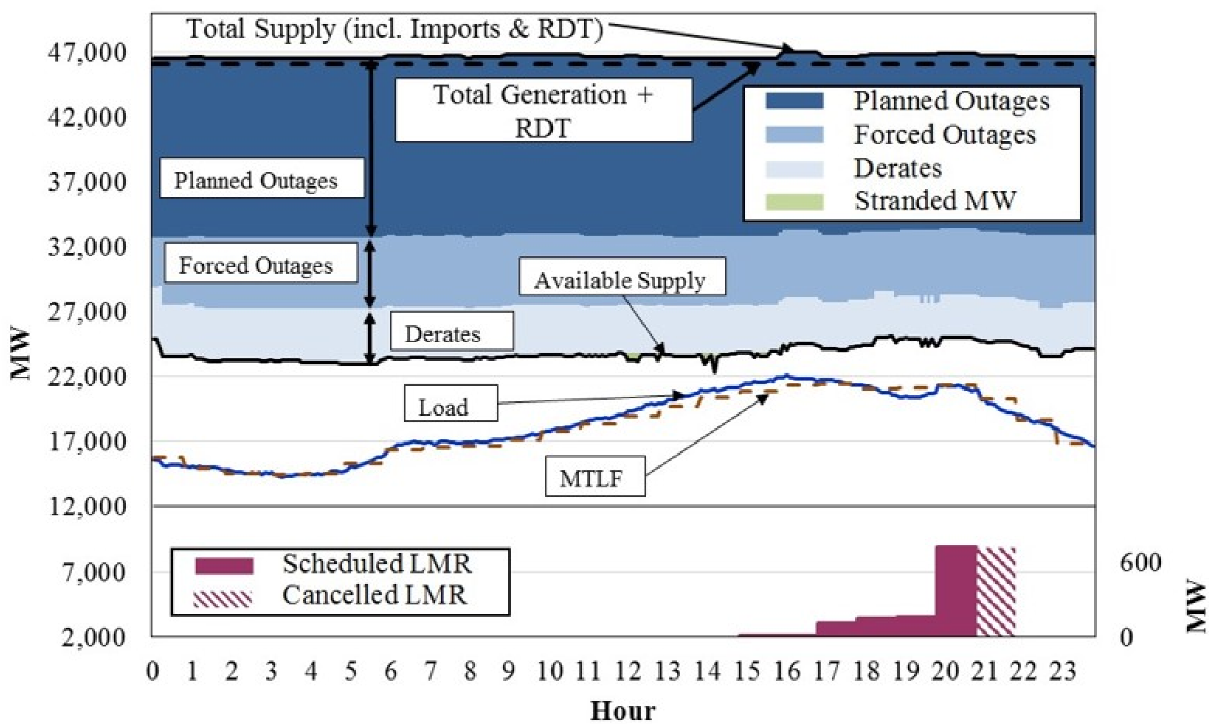
On April 4, 2017, MISO declared a Maximum Generation Emergency in MISO South because of higher than normal load, unusually high planned generation outages, the forced outage of a large unit early in the day, and substantial transmission outages.

Events on April 4 unfolded as follows:

- During the morning ramp period, MISO forecasted tight supply and declared a Maximum Generation Alert.
- By early afternoon, MISO forecasted a capacity shortfall and declared a Maximum Generation Event that quickly escalated.
- For the first time since 2007, MISO called LMRs to address the emergency in the hours from 4pm to 10pm, although MISO cancelled the event for the last hour.

To evaluate this event, we review the availability of generation in MISO South, the forecasted and actual load and the LMR performance on April 4. Figure 13 shows the total supply in MISO South as the top line, including the NSI and the additional 3,000 MW of transfer capability across the RDT from the North while the top dotted line includes only the generation capacity in the South and the RDT capability. The four shaded areas show the various types of outages and other factors that reduced the availability of supply to MISO South. Stranded MWs is output that cannot be produced because it is limited by transmission constraints. The two lines at the bottom of the figure show the Mid-Term Load Forecast (MTLF) and the actual load in the South. The gap between the bottom of the shaded area and the actual load represents the excess supply. Finally, the bottom panel shows the amount of LMRs that were scheduled by MISO.

Figure 4: Maximum Generation Emergency in MISO South
April 4, 2017



During this event, approximately 23 GW of capacity was on outage or derated. MISO anticipated a capacity shortfall and declared a Maximum Generation Event. Conditions were tightest shortly after noon, but the LMR schedules were not substantial until 8 pm, long after the tightest conditions occurred. The LMRs were cancelled shortly thereafter. Although the conditions warranted the emergency declaration, the LMRs provided very little value. The poor timing of the LMR schedules was attributable to the long notification times offered by most of the LMRs. In addition, many of the scheduled LMRs did not meet their full scheduling instructions during the event. We discuss the implications of these issues in Section IX.B.

During this event, emergency pricing went into effect but did not materially affect prices because MISO South was not close to being short of energy. However, MISO commits units to maintain sufficient excess capacity in the South to respond to its largest contingency. Effectively, these are operating reserves that are not procured through the market. It is likely that MISO was short of the excess capacity it targets to hold during this event. We have recommended that MISO implement a 30-minute reserve product to reflect MISO's operating needs. Were this reserve product in place, prices in MISO South would have likely reflected local reserve shortages.

September 22-25, 2017: Late Season Heat Wave and TVA TLR

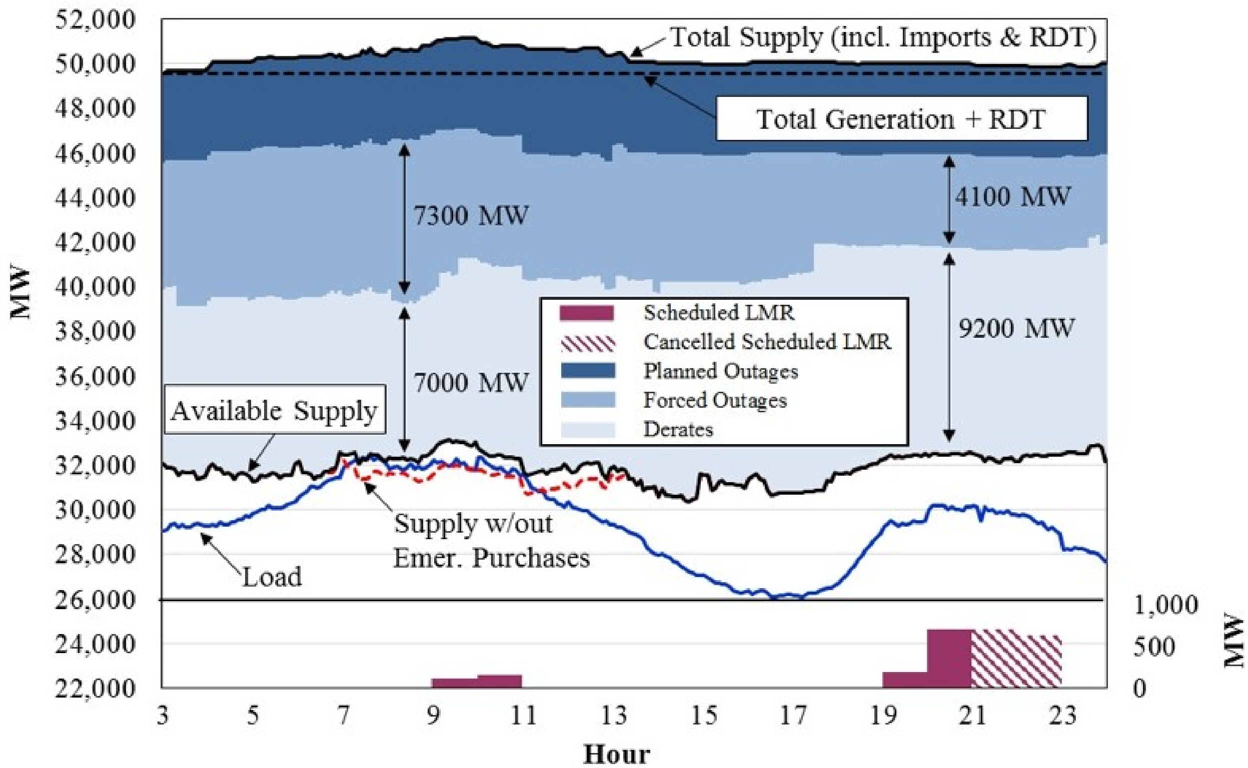
Beginning on September 20, MISO experienced unseasonably warm weather with average temperatures exceeding 91 degrees on September 22. Temperatures and load were significantly under-forecasted on September 22 and MISO declared a Maximum Generation Event. High seasonal planned outage rates and 1,100 MW of forced outages early in the afternoon contributed to tight system conditions. MISO called on emergency resources and set an emergency offer floor price of $847 per MWh, but it did not set prices.

During the September emergency events, TVA invoked TLR procedures for a constraint on two days, which exacerbated the operating conditions. TVA called a TLR for the Volunteer-Phipps Bend constraint on September 22 as a proxy to obtain relief on a lower voltage constraint that would not qualify for TLR. This led to significant redispatch and price distortions throughout the entire MISO footprint. This was grossly inefficient because most of the LMP and dispatch effects were at locations that had no material effect on the underlying 161kV constraint. Volunteer Phipps Bend was not close to its limit, yet MISO redispatch in response to the TLR contributed to more than 100 dispatch violations of MISO's own constraints.

January 17 and 18, 2018: LMR Deployment in MISO South

On January 17 and 18, 2018, unusually cold weather in the South region resulted in a record winter peak load level in the South of 32.1 GW. On the January 17, conditions were extremely tight from 6 a.m. to 1 p.m. MISO's load forecast in the early morning showed a significant capacity deficiency by 9 a.m., prompting MISO to declare a Maximum Generation Event. The conditions on January 17 are shown in Figure 5.

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



During this event on January 17:

- The actual load was well below the forecast during the peak hours from 7 to 9 a.m., partially because of voluntary load curtailments.
- However, additional forced outages of 2.5 GW occurred between midnight and 8:30 a.m. because many of resources in the South region are not well fortified for the unusually low temperatures that occurred in the South region.
- In addition, MISO relaxed some of its transmission limits in the South by raising them by roughly 25 percent.
- Because load exceeded supply, MISO exceeded the RDT limit for roughly an hour from 6:45 a.m. to 7:45 a.m., by a maximum of almost 1,000 MW at 7:25 a.m. Exceeding the RDT could only be avoided by shedding firm load in MISO South.
- MISO scheduled emergency transactions beginning at 7:30 a.m. that exceeded 1,000 MW by 9 a.m., allowing it to reduce the RDT flows to below the limit.
- MISO declared an emergency for the evening peak on the 17th and the morning of the 18th, but conditions were less tight because some units returned to service from outage.

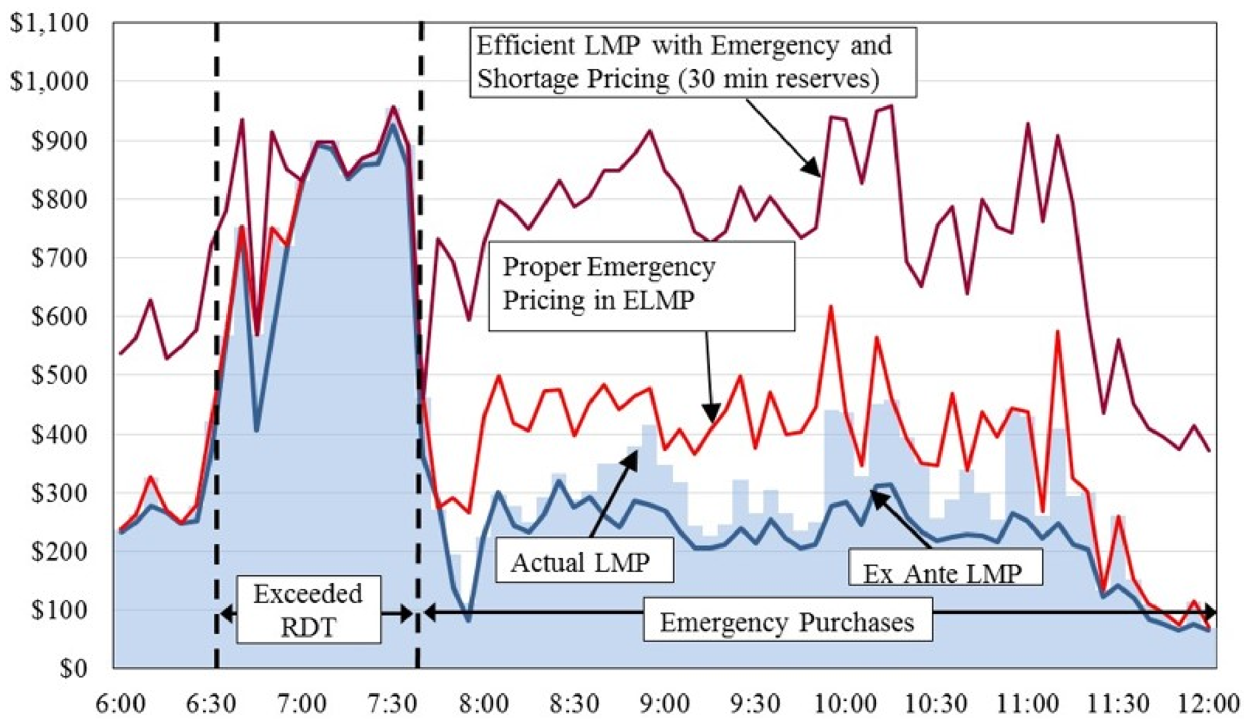
Based on our evaluation of the January 17, 2018 events, we conclude that MISO's operating actions were necessary to avoid firm load curtailments in the South. However, this event also highlights concerns with the utilization of LMRs. As summer-only resources, the LMRs were not obligated to offer during any of the events described above. Once again, MISO could only schedule a very small quantity of LMRs well after the worst of the conditions had passed. This event underscores the value of reconsidering how MISO calls on these resources and the capacity credit granted to LMRs under Module E, which we discuss in more detail in Section IX.B.

Evaluation of Emergency Pricing on January 17, 2018

In addition to the operational analysis provided above, it is important to review MISO energy pricing in the South during this event because this was a serious emergency that required numerous actions by MISO operators.

Figure 6 shows our evaluation of prices during the January 17 event. The blue line indicates the ex-ante LMP, and the blue shading in the background indicates the ex-post LMPs. Through the course of this analysis, we concluded that MISO's emergency pricing did not perform well. The red line indicates the price that the ELMP model should have produced. Actual ELMP prices were lower because it did not properly account for the impact of the emergency power purchases on the RDT. Finally, the top dark line shows our estimate of an efficient energy price during this event, which would include pricing the shortage of the reserves in the South that MISO attempts to hold. For this figure, we assume a demand curve for these reserves of $500, which we believe reflects their approximate value to the system.

Figure 6: Evaluation of Real-Time Emergency Prices
January 17, 2018



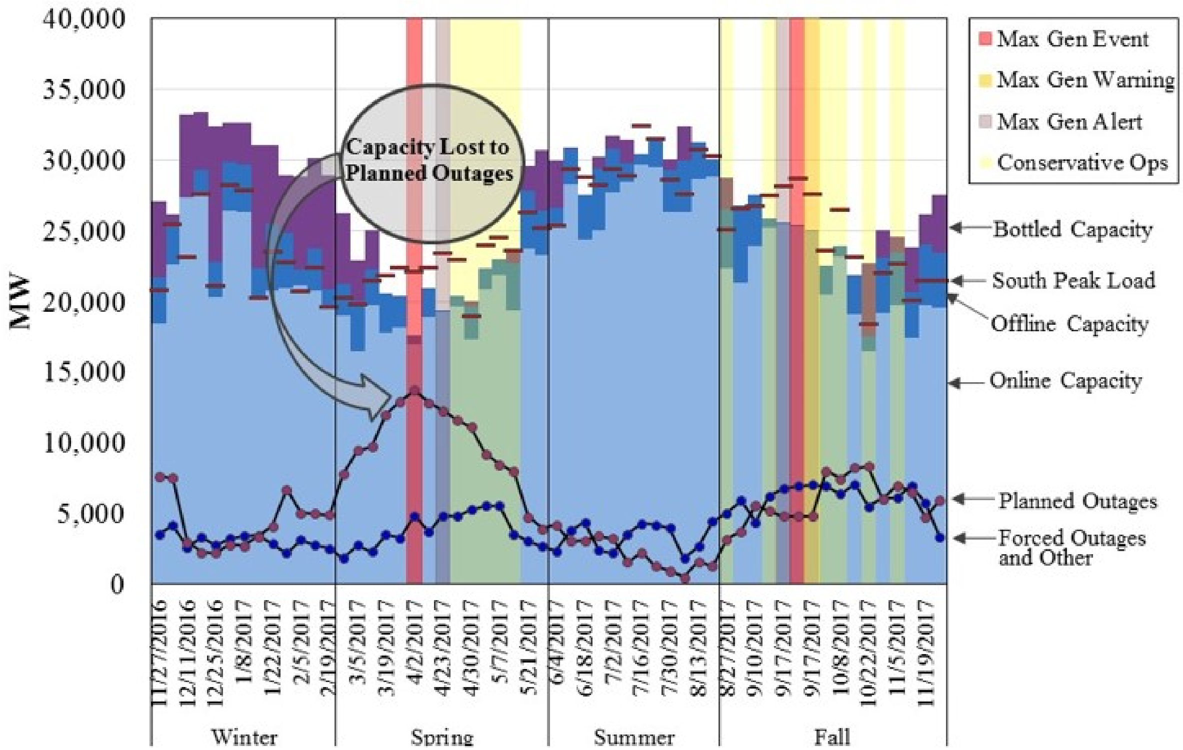
Our evaluation of the energy prices during the event on January 17 allows us to conclude:

- Prices were high when the RDT was violated because of the RDT demand curve.
- Once the emergency purchases began and RDT flows fell, the emergency pricing in the ELMP model did not properly account for RDT flows. This resulted in the emergency resources not setting prices when they should have and lower real-time prices.
- Even if ELMP had operated properly, prices would have been inefficiently low because:
    - The emergency price floor was set by a unit's offer at an inefficiently low level – allowing a resource's offers to determine the floor can result in an inefficiently high or low floor and we recommend MISO establish reasonable floors in its Tariff.
    - 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 procure this in the market, which will price future shortages at the levels estimated in the figure.

E. Outage Scheduling and Emergency Events

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. In 2017, MISO South experienced a pattern of high planned and forced outages in the shoulder months that contributed to tight operating conditions and emergency conditions. Figure 7 shows MISO's available capacity, outages, peak load, and emergency conditions in MISO South.

Figure 7: MISO South Outages and Tight Operating Conditions
2016 – 2017



Planned outages in MISO South have had a significant impact on MISO's ability to operate the system reliably, and in multiple instances have contributed to MISO declaring Max Gen Alerts, Warnings, and Emergencies during shoulder seasons. These emergencies occur because weather patterns can cause unusually high load during the shoulder seasons when outages reduce generator availability. Conversely, the figure shows that during the winter peak months, a large amount of capacity in MISO South was idle because it was "bottled". Bottled capacity in the South are resources that cannot be utilized because they are not needed in the South and are unable to be exported to the North because of the RDT scheduling constraint. These results reveal that more disaggregated outage scheduling could mitigate the tight operating conditions that have arisen in the shoulder months. In section VI.B we also show that poor outage coordination has also led to inflated congestion costs.

In our 2016 SOM Report, we recommended MISO enhance its transmission and generation planned outage approval authority (see 2016-3). In 2017, MISO introduced the Resource Availability and Need (RAN) project to address an array issues that have become apparent in recent years, including outage coordination. Also, MISO has provided participants with the results of the Maintenance Margin Tool on OASIS[6] to communicate MISO's supply availability and help coordinate outages. We do not believe that the Maintenance Margin Tool alone addresses our outage coordination concerns, and could possibly increase outage concerns if it signals to large suppliers with market power when supplies are tight. Ultimately, 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.

F. 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 2017.

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 8 and Figure 9 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).

6 This MISO tool forecasts resource margins by Planning Area in future months based on MISO load forecasts and currently approved planned generation and transmission outages.

Figure 8: Net Revenue Analysis
Midwest Region, 2015–2017

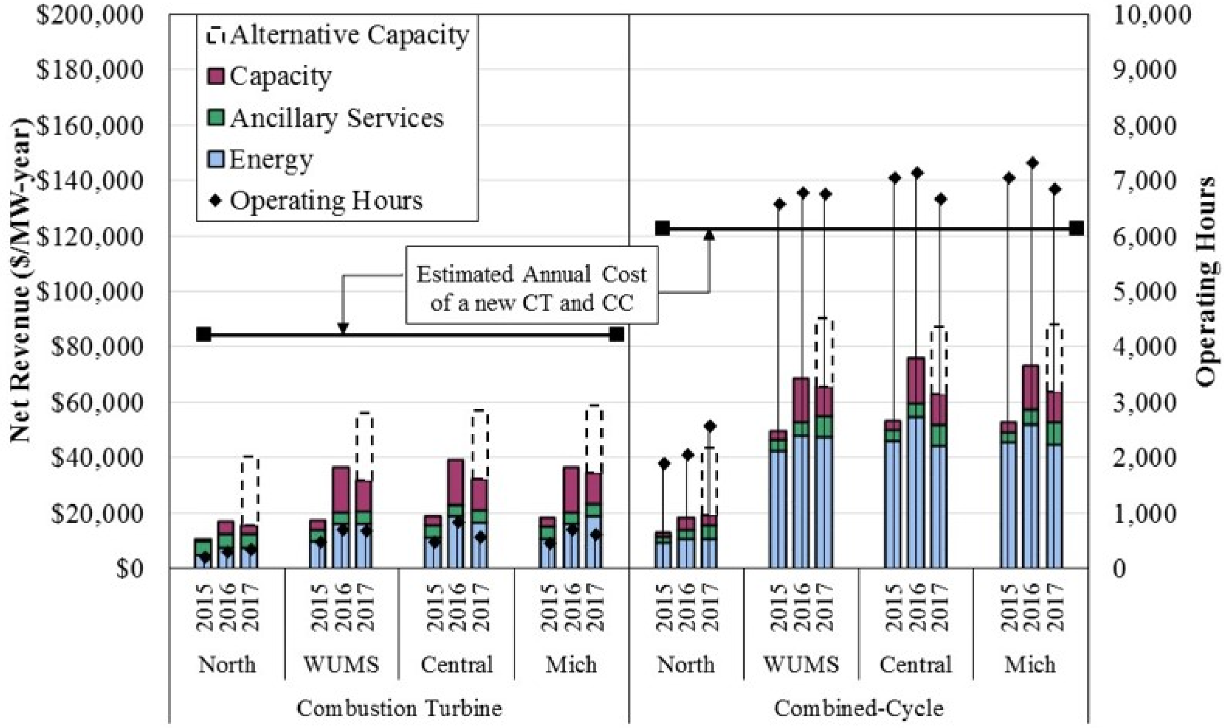
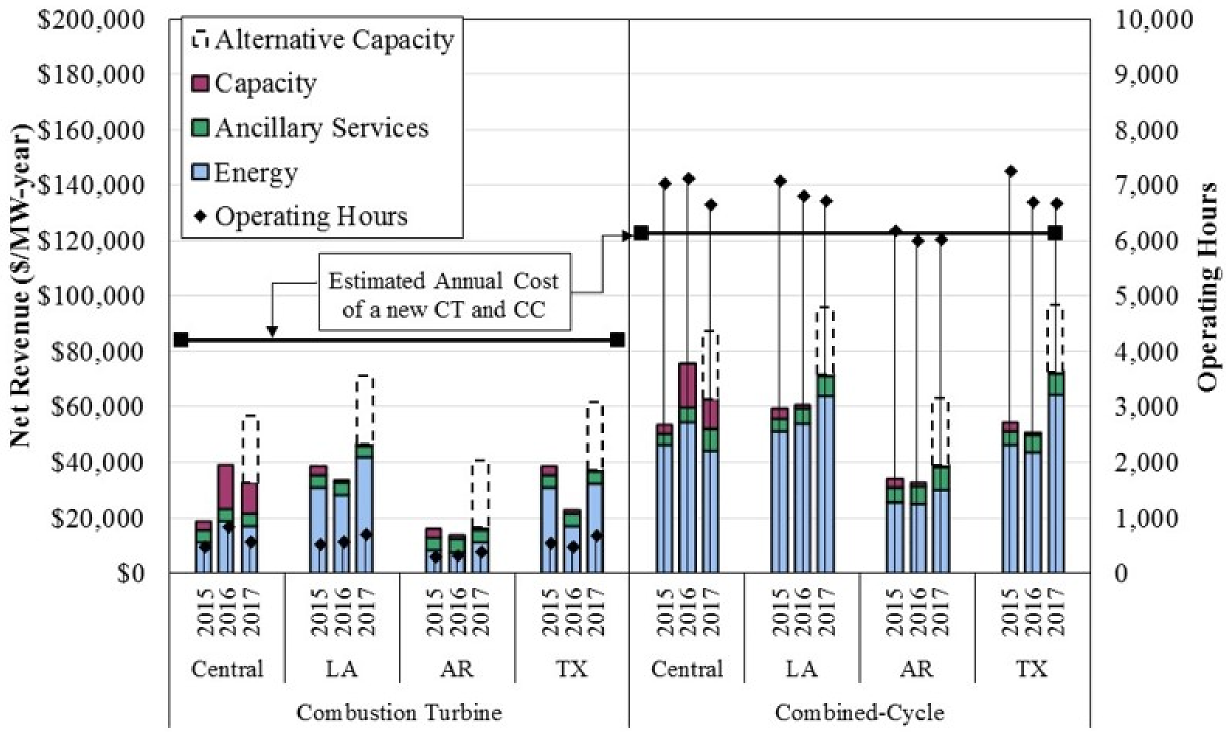


Figure 9: Net Revenue Analysis
South Region, 2015–2017



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

Changes in the net revenues were mixed in 2017.

- In the Midwest Region, the estimated net revenues for both types of units fell as a result of reduced capacity auction revenue from the 2017/2018 PRA.
- Estimated net revenues in the South Region for both types of units increased substantially in 2017 because of higher levels of congestion, particularly during shoulder months.
- Energy revenues caused by congestions in Texas caused net revenues for combustion turbines and combined-cycles to rise there the most -- 88 and 61 percent, respectively.

Nonetheless, net revenues continue to be substantially less than CONE in all regions. The relatively low net revenues are consistent with expectations because of infrequent scarcity pricing events, the small prevailing capacity surplus, and capacity market design issues.

Capacity market design issues continue to undermine MISO's economic signals. This 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.

These figures show the substantial additional capacity market net revenues that would have been generated in 2017 if our proposed change to remedy the capacity market design flaw had been implemented. The net revenue would still be less than CONE because of the capacity surplus that existed in 2017. The next section includes a discussion of these capacity market design and performance issues.

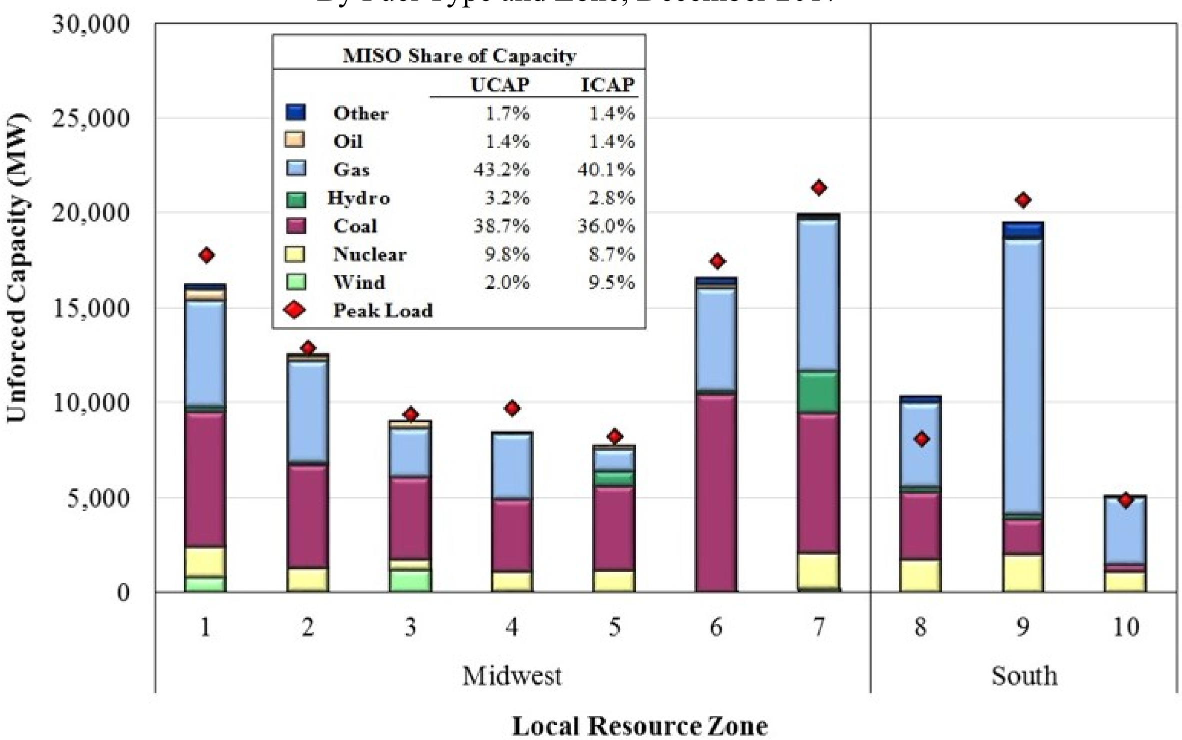
III. Resource Adequacy

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 and fuel type. Figure 10 shows the distribution of Unforced Capacity (UCAP) at the end of 2017 by zone and fuel type, along with the 2017 coincident peak load in each.[7] 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 nine percent of MISO's ICAP, it is two percent of the UCAP.

Figure 10: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2017



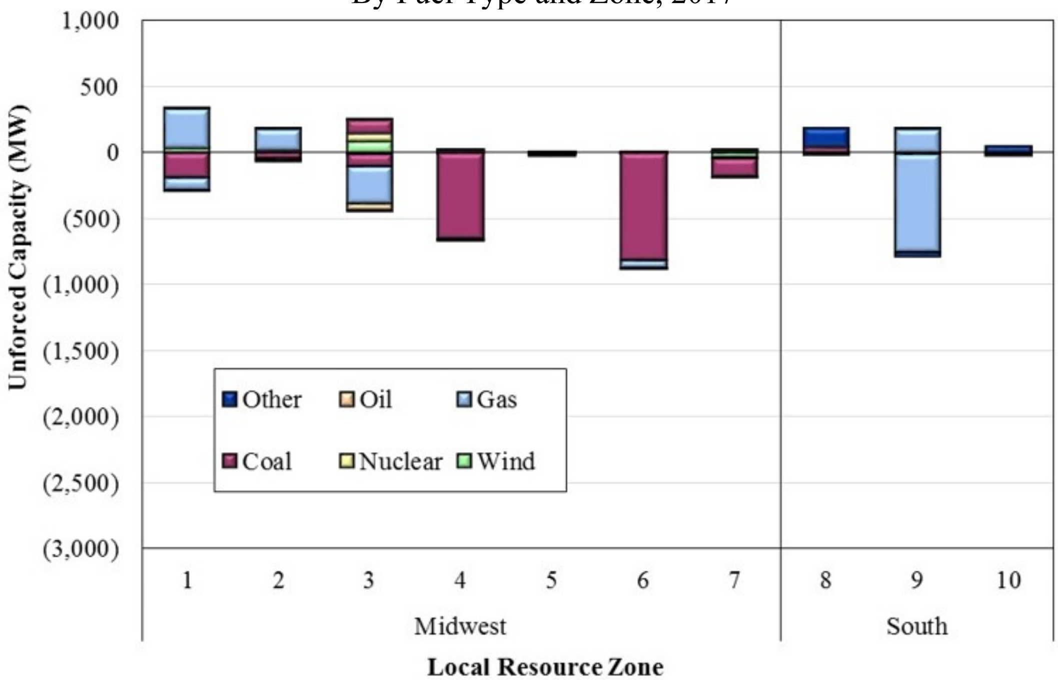
This figure shows that gas-fired resources now account for a larger share of MISO's capacity than any other capacity type, including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from the South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

7 UCAP was based on data from the MISO PRA for the 2017/2018 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 7 shows the capacity additions (positive values) and losses during 2017.

Figure 11: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone, 2017



Capacity Losses

In 2017, 3.8 GW of resources exited MISO. Environmental regulations promulgated by the U.S. Environmental Protection Agency in recent years and low gas prices led to continuing coal-fired unit retirements, which totaled 2.2 GW in 2017. These retirements led to a net capacity loss of 2.6 GW, which we expect to continue based on the weak economic signals provided by MISO's current capacity market design.

New Additions

Most of the 1.2 GW of new capacity additions in MISO were natural gas-fired resources. Additional investment in wind resources may occur in the coming years as Multi Value Projects (MVP) are completed, which include 17 transmission projects that are estimated to cost more than $6.6 billion. Five of these projects are completed, while nine are underway and expected to be completed between 2018 and 2019. The remaining are pending.

Planning Reserve Margins

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2018. We have worked closely with MISO to ensure that our

Base Case planning reserve level is consistent with MISO's assumptions in its *2018 Summer Resource Assessment,* with one notable exception. MISO assumes a transfer limit assumption of 1,500 MW (consistent with the 2018/2019 PRA), while we assume a probabilistic derated transfer capability of 2,000 MW. We assume this larger amount because, in actual operations, MISO has access to the full RDT transfer limit under nearly all conditions. Because of other smaller differences in assumptions, our Base Case margin is essentially the same as MISO's.[8]

Table 2 shows three scenarios that examine how variations in demand response (load-modifying resources or "LMRs") and unusually hot temperatures affect MISO's planning reserve margins.

Table 2: Summer 2017 Planning Reserve Margins

		Alternative IMM Scenarios			
			Realistic DR*	High Temperature Cases	
	Base Case	Realistic DR*	< 2 HR	Realistic DR*	< 2 HR DR
Load					
Base Case	124,704	124,704	124,704	124,704	124,704
High Load Increase	-	-	-	5,984	5,984
Total Load (MW)	124,704	124,704	124,704	130,688	130,688
Generation					
Internal Generation Excluding Exports	134,694	134,694	134,694	134,694	134,694
BTM Generation	4,576	4,576	1,450	4,576	1,450
Hi Temp Derates**	-	-	-	(4,900)	(4,900)
Adjustment due to Transfer Limit***	(853)	(647)	-	-	-
Total Generation (MW)	138,417	138,623	136,144	134,369	131,244
Imports and Demand Response					
Demand Response***	7,137	5,709	2,474	5,709	2,474
Capacity Imports***	3,183	3,183	3,183	3,183	3,183
Margin (MW)	24,033	22,811	17,097	12,574	6,213
Margin (%)	**19.3%**	**18.3%**	**13.7%**	**10.1%**	**5.0%**

* Assumes 80% response to account for uncertainties in availability and performance.
** Derates are highly variable; this value is based on four of the hottest days since the start of the MISO markets.
*** Cleared amounts for the 2018 / 2019 planning year.

The columns in Table 2 include a number of cases:

- Column 1: Base case that assumes that MISO will receive full response from its Demand Response (DR) resources (interruptible load and controllable load management) when they are deployed.
- Column 2: Assumes that MISO will only receive 80 percent responses from the DR resources. DR resources are not subject to comparable testing to generators and have not fully performed in the rare cases when they have been deployed. However, MISO's certification requirements, operational awareness of available DR, and penalties for failing to respond have all improved. Hence, an 80 percent assumed response is realistic.
- Column 3: Modifies column 2 by removing DR resources that cannot respond within two hours because DR can only be accessed if MISO calls a Maximum Generation Event Step

8 MISO limits the QF capacity credit to the ICAP-equivalent of cleared capacity in the PRA. Additionally, MISO provides a greater capacity credit for resources that have ERIS interconnection service with TSR.

2. Because these events are often precipitated by unforeseen outages and other contingencies, MISO often is not able to declare an event of this level more than two hours in advance of the most critical conditions.

- Columns 4 and 5: The same as columns 2 and 3, but assume hotter than normal summer peak conditions that correspond to a "90/10" case (should only occur one year in ten).

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.[9] In its *2018 Summer Assessment*, MISO shows a high-load scenario that includes an estimate of high temperature derates. While we believe this scenario is a realistic forecast of potential high-load conditions, we continue to believe that it likely understates the derates that may occur under high-temperature conditions.

The results in the table show that the capacity surplus varies considerably in these scenarios:

- The baseline capacity margin for the MISO Midwest region is more than 19 percent, which substantially exceeds the Planning Reserve Margin Requirement of 17.1 percent. This is higher than last year, which is because of a lower peak load forecast and higher cleared LMRs.
- The high-temperature cases show much lower margins—as low as 10 percent when DR is derated to a realistic level. This is significant because this margin must provide MISO's operating reserves (2,400 MW) and includes no forced outages, which generally range from five to eight percent but may be much higher because of correlated factors (e.g., during periods of extreme temperatures).

Overall, these results indicate that the system's resources should be adequate for summer 2018 if the peak demand conditions are not substantially hotter than normal. However, planning reserve margins will likely decrease as resources retire 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. 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

9 There is significant uncertainty regarding the size of these derates, so our number in the table is an average of what was observed on extreme peak days in 2006 and 2012.

participant during this period of delayed retirement or suspension. SSR status has been granted very infrequently. The only current SSR agreement was executed on April 1, 2017 with one unit in MISO South. This agreement is currently estimated to expire in June 2018.

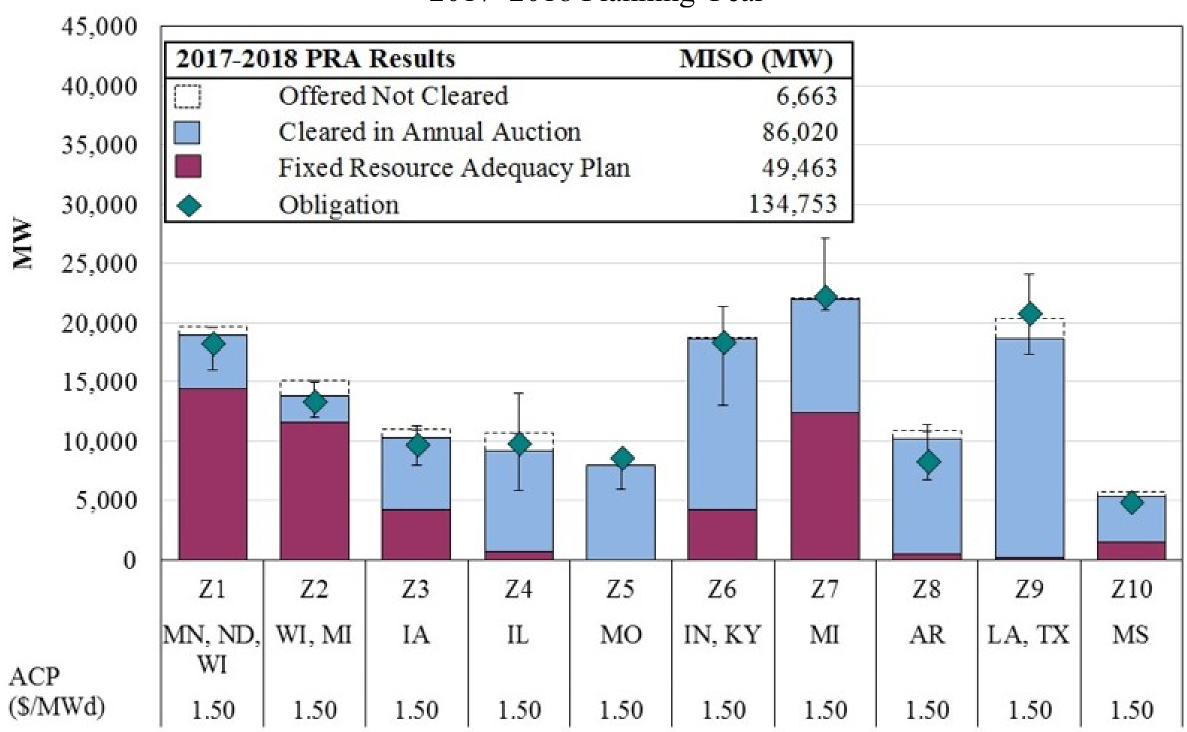
As retirements accelerate, it is very important that the capacity market, the Attachment Y, and SSR processes are well aligned to allow the market to facilitate reasonable retirement decisions and capacity market outcomes. These issues are discussed in the following subsection.

D. 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 with a goal to efficiently satisfy the planning requirements in conjunction with their energy and ancillary services markets. The economic signals provided by the capacity market and energy and ancillary services markets inform long-term capacity 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. Figure 12 shows the outcome of the PRA held in April 2017 for the 2017-2018 Planning Year.

Figure 12: Planning Resource Auctions
2017–2018 Planning Year



The figure shows the obligation in each zone, along with the minimum and maximum amount of capacity that can be purchased in each zone. The obligation is 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.

Because no zonal constraints were binding in the 2017-2018 auction, the auction clearing price in all zones was $1.50 per MW-day. This low price, effectively $0, provides suppliers with less than one 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.

As part of the Settlement Agreement with SPP,[10] 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, 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 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.

FERC approved several changes that were in effect for the 2017/2018 PRA, which included:

- Imposing physical withholding at the affiliate level rather than the market participant level;
- Excluding LMR Demand Resources, Energy Efficiency Resources, and External Resources from mitigation in the PRA;
- Allowing market participants to use default technology-specific avoided costs for the calculation of the Facility Specific References Levels (FSRLs); and
- Including a formulaic method for implementing a Going Forward Cost (GFC) in the MISO tariff.

E. 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 three factors; (1) the design of the PRA demand curve; (2) barriers to participation affecting units with retirement plans within the planning year; and (3) the local resource zones that do not adequately reflect transmission limitations. We discuss all three of these issues.

10 Agreement with MISO, SPP, and other first tier entities filed October 15, 2015, in docket EL14-21-000.

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.[11]

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 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.

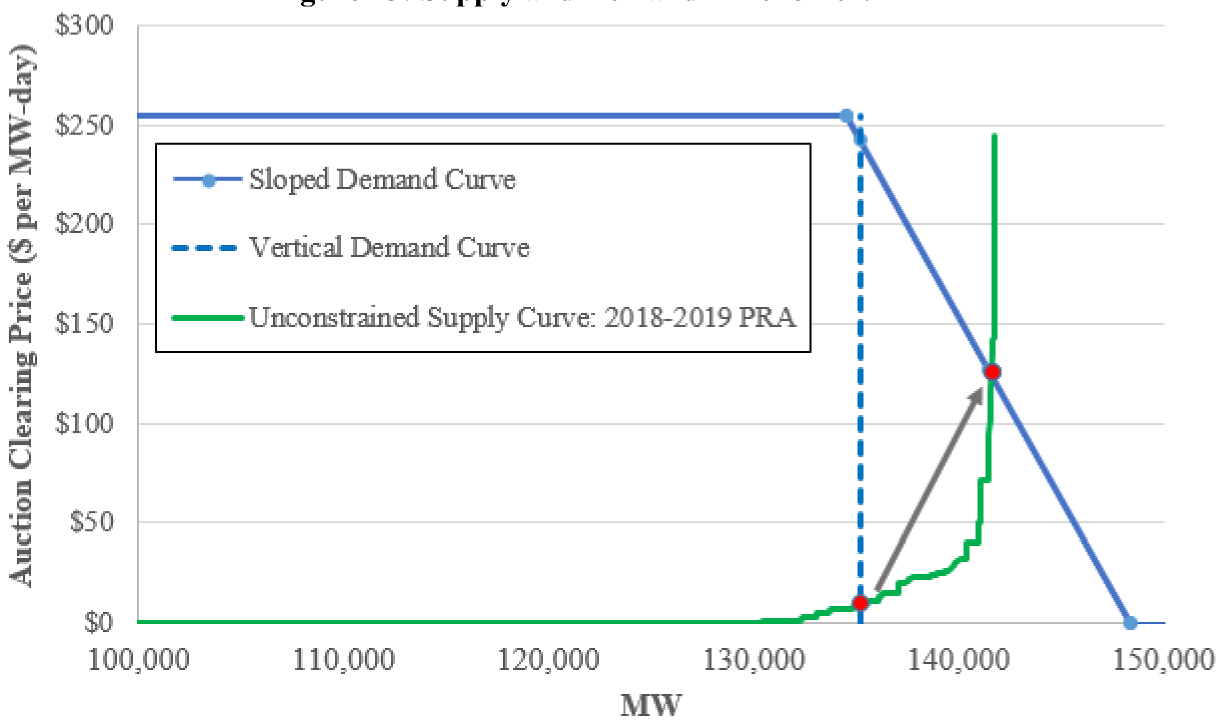
Like many of our previous *State of the Market Reports,* our protest of the MISO Module E filing sought to address this flaw by recommending that MISO implement a sloped demand curve. A sloped demand curve would produce more stable and predictable pricing, which would increase the capacity market's effectiveness in providing incentives to govern investment and retirement decisions. A sloped demand curve also reduces the incentive to exercise market power. This is 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 need for a sloped demand curve will increase as planning reserve margins fall toward the minimum requirement level, the result of significant amounts of capacity exiting MISO.

To demonstrate the significance of the design flaw, we simulated the clearing price in MISO that would have prevailed in the 2018/2019 PRA, conducted in March 2018, if MISO employed sloped demand curves in the PRA. Figure 13 depicts this simulation. The blue dashed line in

11 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.

Figure 13 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 Appendix Section III.D we detail the assumptions used to construct sloped demand curve.

Figure 13: Supply and Demand in 2018-2019 PRA



In the 2018/2019 MISO PRA, more than 135 GW of capacity cleared at a clearing price of $10.00 per MW-day, except for zone 1 that was export-constrained and cleared at $1.00 per MW-day. In the sloped-demand-curve alternative, roughly 142 GW of capacity cleared. In this case, zone 8 was export-limited and cleared at $111.06 per MW-day and the rest of the MISO footprint cleared at $121.18 per MW-day. This is roughly half of the CONE in MISO. Hence, the sloped demand curve increased prices by more than 12 times the actual clearing price, which is a much more accurate reflection of the marginal reliability value of capacity in MISO. This enormous difference in price highlights the serious impact of the flawed market design under the current market 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 2018/2019 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 3.

Table 3: Effects of Sloped Demand Curve by Type of Participant
2018-2019 PRA ($Millions)

Type of MP	Net Revenue Increases	Net Revenue Decreases	Total
Vertically-Integrated LSEs	$ 351	-$ 320	$ 32
Merchant Generators	$ 413		$ 413
Retail Choice Load		-$ 445	-$ 445

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, 60 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 (more than $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 $445 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 implementing a sloped demand curve is the most important design improvement for MISO's PRA, we have recommended a number of other improvements as well:

- *Coordinating Attachment Y and the PRA.* The PRA should assist suppliers in making efficient decisions regarding their resources, including whether to retire their units. In order to do this, MISO filed a proposal to modify the PRA rules to allow:[12]
  - Units with Attachment Y retirement requests to participate in the PRA and, if they clear, to defer the effective date of the retirement.
  - Units under SSR contracts to participate in the PRA without undue risk by providing an assurance that either a) the SSR contract will not be terminated prior to the end of the capacity obligation, or b) the capacity obligation would terminate if the SSR contract is terminated prior to the end of the capacity obligation period.

[12] The filing was under Docket No. ER18-1636 on May 16, 2018. FERC has not yet approved by FERC this filing at the time of this report.

- *Seasonal Capacity Market.* Adopting a seasonal capacity market would better align the revenues and requirements of capacity with the value of the capacity. 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.

IV. Day-Ahead Market Performance

MISO's spot markets for electricity operate in two time frames: real time and a 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.[13] Resources that clear in the day-ahead market receive financially-binding schedules and settle any deviations at real-time prices.[14] The day-ahead market performed competitively in 2017.

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

- Because most generators in MISO are committed through the day-ahead market, good market performance is essential to efficient commitment of MISO's generation;[15]
- 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 well 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 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.

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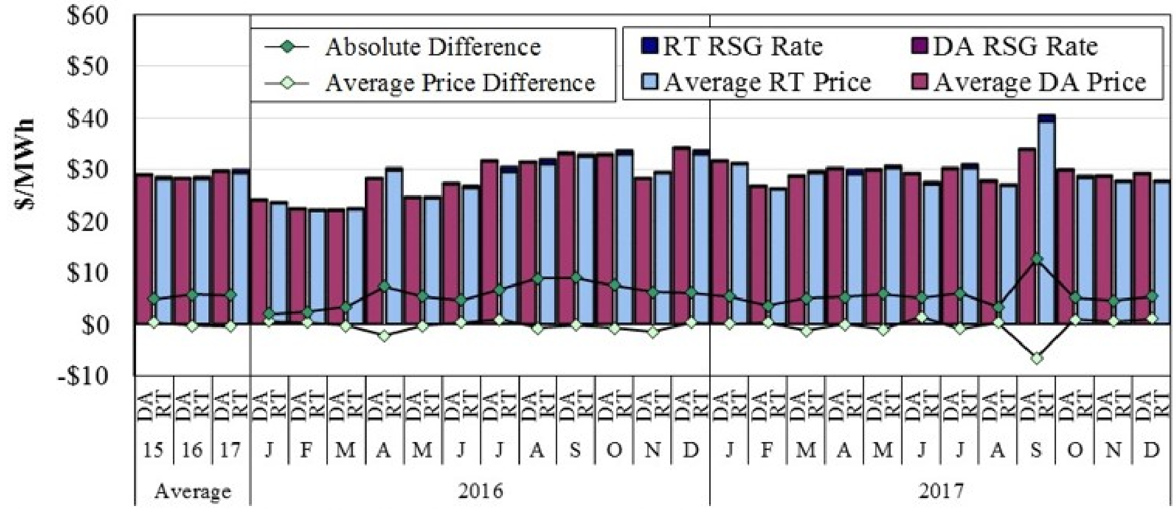
13 In addition to the normal day-ahead market commitment, MISO utilizes the Multi-Day Forward Reliability Assessment Commitment process to commit resources in order to satisfy reliability requirements in certain load pockets that may require long-start-time resources.

14 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.

15 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.

Figure 14: Day-Ahead and Real-Time Prices
2016–2017



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

Indiana Hub	1	-1	-1	2	1	-1	-7	-1	1	3	-2	0	-2	-5	1	0	1	-4	0	-3	5	-3	1	-16	3	2	4
Michigan Hub	1	0	-2	4	3	-1	-6	4	0	5	-9	-2	4	-1	2	1	1	-6	-1	-1	0	-3	1	-11	-1	0	2
Minnesota Hub	2	-1	-1	4	5	-3	2	6	-5	0	-6	-2	-2	2	-6	3	3	-1	-5	1	5	-7	2	-7	-10	3	0
WUMS Area	1	-1	-1	4	3	0	0	1	-3	-5	-7	1	4	1	-6	-1	-2	3	-1	3	3	-8	3	-11	0	0	2
Arkansas Hub	1	0	0	2	2	-3	-3	7	4	-1	0	-3	-2	-6	0	1	3	-3	0	2	5	-7	2	-2	5	-3	1
Louisiana Hub	-2	-2	-1	2	3	-2	2	1	-14	-1	-4	-3	1	0	1	1	-2	2	-4	3	-1	-9	-6	-1	7	-5	5
Texas Hub	-4	1	1	1	6	3	-18	13	2	-3	1	2	3	-1	2	-2	3	-2	3	4	-1	-1	3	1	8	-6	4

Day-ahead premiums were effectively zero on average after adjusting for the real-time RSG DDC, which averaged $0.52 per MWh. However, there were a number of congestion episodes that caused transitory divergence in different areas:

- During the spring, planned generation and transmission outages and volatile load in MISO Central led to periods of high real-time congestion and high real-time prices.
- Day-ahead premiums occurred because of the solar eclipse and coincident thunderstorms on August 21 that caused real-time load to be nearly 8,000 MW under the forecast.
- In late September, high outages, unusually hot temperatures, and corresponding high loads led to large real-time price premiums in the North. This was exacerbated by a TLR called by TVA that led to very inefficient redispatch and price spikes in the North.

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 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
2017

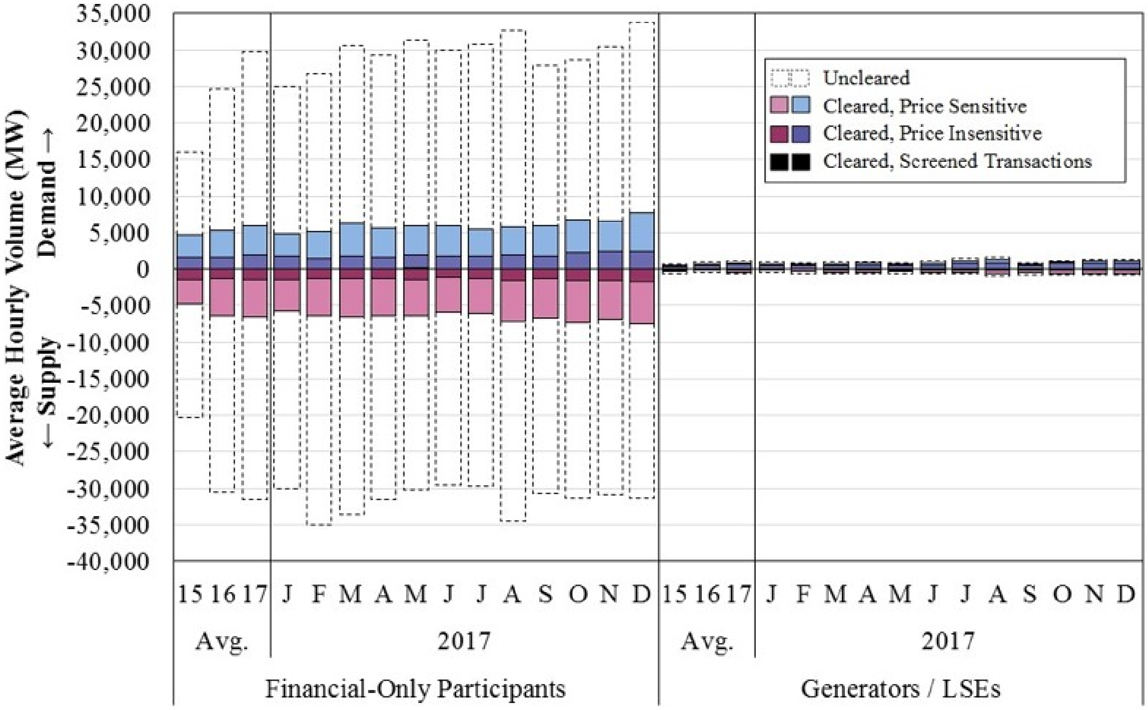


Figure 15 shows that offered volumes increased by more than 10 percent from last year. Several market participants submit "backstop" bids, which are bids and offers priced well below (in the case of demand) or above (supply) the expected price range. Backstop bids and offers clear less than one percent of the time, but they are substantially profitable when they clear. These transactions are beneficial because they mitigate particularly large day-ahead price movements.

Cleared transactions rose 10 percent primarily because of higher levels of cleared demand. As in prior years, the vast majority of virtual transactions are submitted by financial players. Generators and LSEs typically also participate in virtuals to hedge their generation or load positions. Financial participants, who tend to offer virtuals more price-sensitively 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.[16] 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 2017 increased by 15 percent from 2016. Matched transactions are an attempt to arbitrage congestion-related price differences (and avoid any energy price risk). We continue to recommend MISO implement a virtual spread product that would allow participants to engage in such transactions price-sensitively. Such a product would allow participants to specify the maximum congestion difference 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.

C. Virtual Profitability

Gross virtual profitability was slightly higher in 2017, averaging $0.82 per MWh. The transactions by financial participants were generally more profitable, averaging $0.88 per MWh compared to the average profits of $0.22 per MWh for transactions submitted by physical participants. 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 averaged $1.20 per MWh. 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.

16 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).

D. Benefits of Virtual Trading in 2017

We conducted an empirical analysis of virtual trading in MISO in 2017 that evaluated virtuals' contribution to the efficiency of the market outcomes. We determined that 56 percent of all cleared virtual transactions in MISO were efficiency-enhancing. We identified efficiency-enhancing virtuals 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 in this determination 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 at the margin. Virtual transactions that did *not* improve efficiency are those that were unprofitable based on the energy and congestion on modeled constraints. Table 4 shows the percentage of efficient and inefficient virtuals by market participant type in 2017, as well as the average total MWhs of cleared virtual transactions by market participant type.

Table 4: Efficient and Inefficient Virtual Transactions by Type of Participant
2017

	Total	Financial Participants	Physical Participants
Efficient Virtuals	56%	57%	51%
Not Efficient Virtuals	44%	43%	49%
Average MW per Hour	13,733	12,426	1,307

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 $78 million in 2017, a 40 percent increase over 2016. 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 2017.

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 $54.8 million, of which 72 percent was attributable to un-modeled constraints. 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 increased by approximately seven percentage points at the Texas and Louisiana Hubs in 2017, which was due in part to severe weather patterns and increased congestion. 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
2017

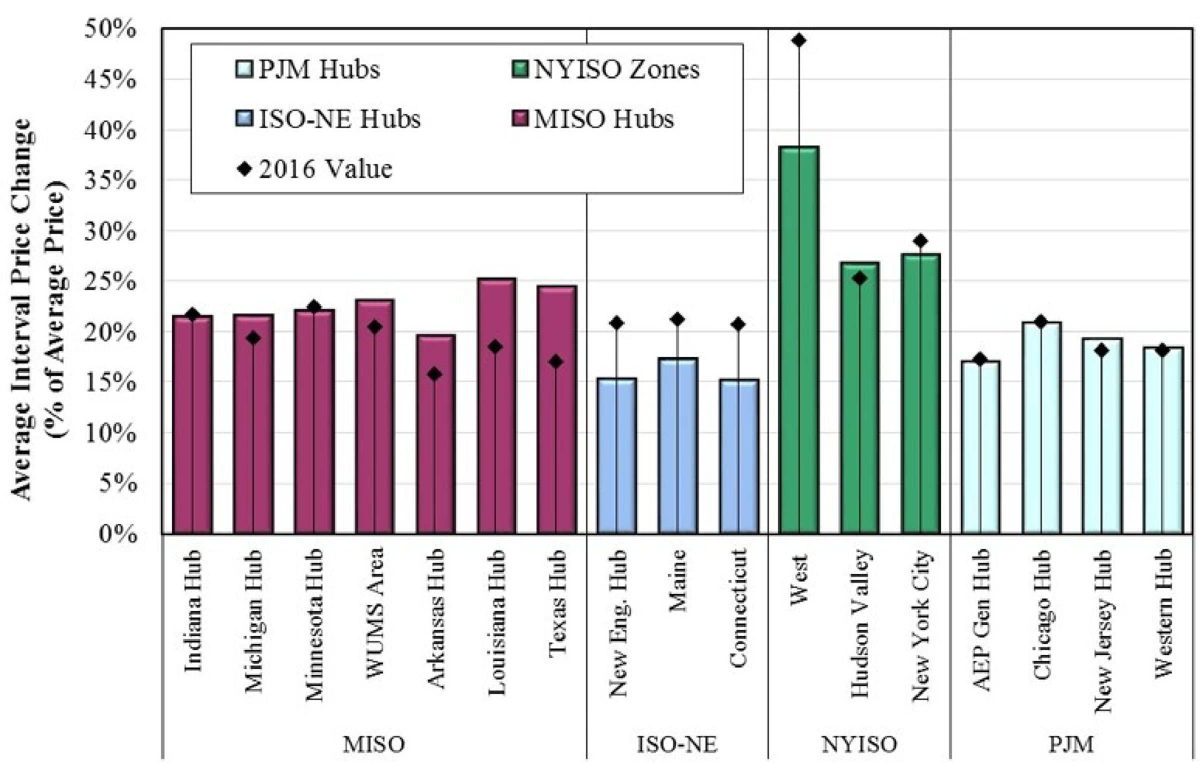


Figure 16 shows that MISO generally had only slightly higher price volatility than PJM and ISO New England in 2017, which is impressive because:

- 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. All else being equal, the multi-period optimization 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.[17] 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[18] 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

17 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.

18 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…."

understated. This leads to substantial RSG costs and poor pricing incentives to schedule 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 2017, increasing the market-wide real-time prices by $0.13 per MWh on average. It had larger effects at certain congestion locations – the average effects ranged from -$1.52 to $2.27 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 $0.41. 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 5.

Table 5: Evaluation of ELMP Online Pricing

Alternative ELMP Methods	Avg. Price Increase ($/MWh)	% of Fast-Start Peaker Eligible	% of Eligible MW Needed
Phase I*	$0.09	5%	
Phase II*	$0.41	26%	0.70%
Plus Day-Ahead Units	$0.92	38%	1.70%
No Ramp Limitation	$1.42	26%	2.00%
Plus DA Units & No Ramp Limit	$1.81	38%	2.50%

* Phase I shows annual results from 2016. Phase II shows the last eight months in 2017.

This table shows the average price increase achieved by the online pricing in ELMP under the Phase I and Phase II assumptions, and estimates the price effects of expanding eligibility to include day-ahead scheduled units and relaxing the ramp rate assumption.

Although an improvement, the Phase 2 changes only allow 26 percent of MISO's peaking resources to set prices so the effects have been modest. In past reports, we have recommended that MISO extend eligibility to units scheduled in the day-ahead market, which would increase participation to 38 percent of the peaking output. We have also recommended extending the minimum runtime criteria to two hours, which would expand eligibility to nearly all peaking resources. This latter change is likely less critical than changing the ramp limitation assumption.

The table above shows that including day-ahead scheduled resources would have more than doubled ELMP's effectiveness to an average increase of $0.92, while relaxing the downward ramp limitation on the peaking resources would double it again to more than $1.80 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 be 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 6 below summarizes our results.

Table 6: Evaluation of Offline ELMP Price Setting
2017

	Economic*	Started	Economic & Started
Operating Reserve Shortages	16%	11%	**4%**
Transmission Shortages	51%	12%	**11%**

**Does not include units that were never started, which would increase the values to: 20% for OR shortages and 61% 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 (4 and 11 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 any RTO are shortages of operating reserves (i.e., RTOs will hold less reserves than its requirement rather than not serving the energy demand). 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-valued 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 and facilitating optimal interchange and generator commitments in the short-run. An efficient ORDC should be consistent with these principles:

- Reflect the marginal reliability value of reserves at each shortage level;
- Consider all supply contingencies, including multiple simultaneous contingencies; and
- 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 that do not track the marginal reliability value of operating reserves; and
- MISO's current VOLL of $3,500 is understated.

Figure 17 shows the current ORDC and a second curve that illustrates the IMM's proposed economic ORDC. Small shortages of less than four percent are priced at the lowest step of $200, but 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. This single step to $2000 is intended to be consistent with FERC's Offer Cap rule.[19]

19 "Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators," 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.[20] 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 RDC to Current ORDC

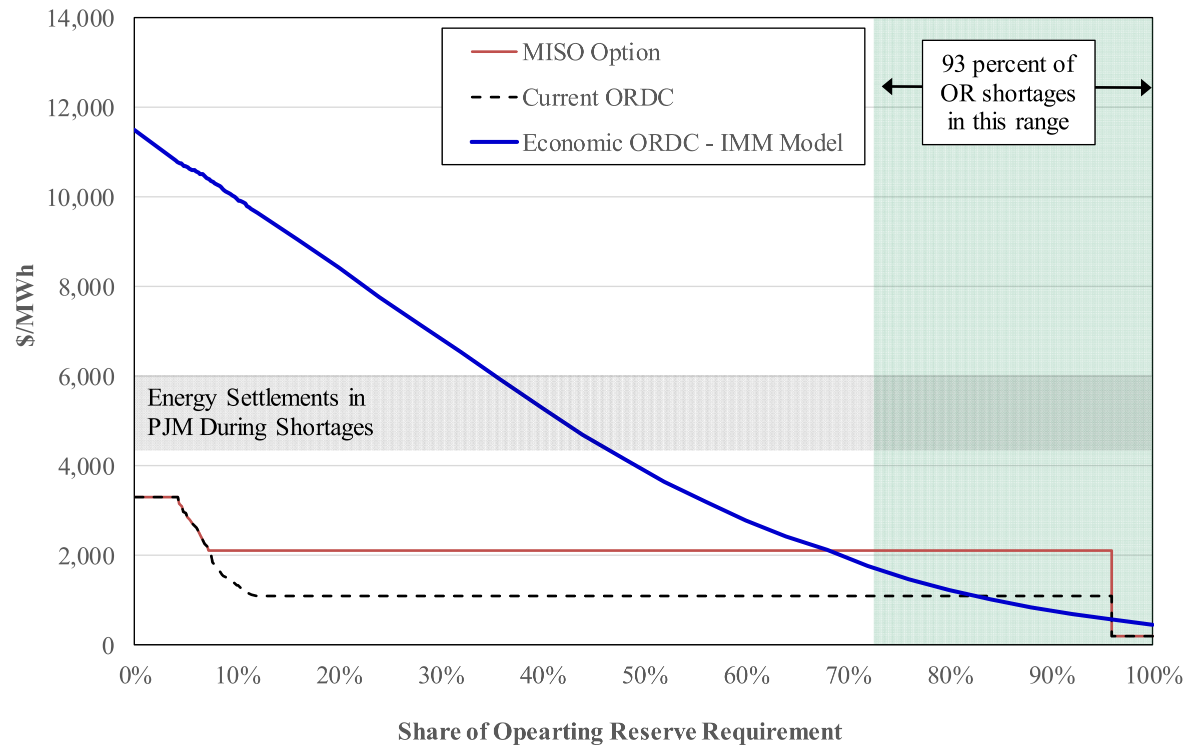


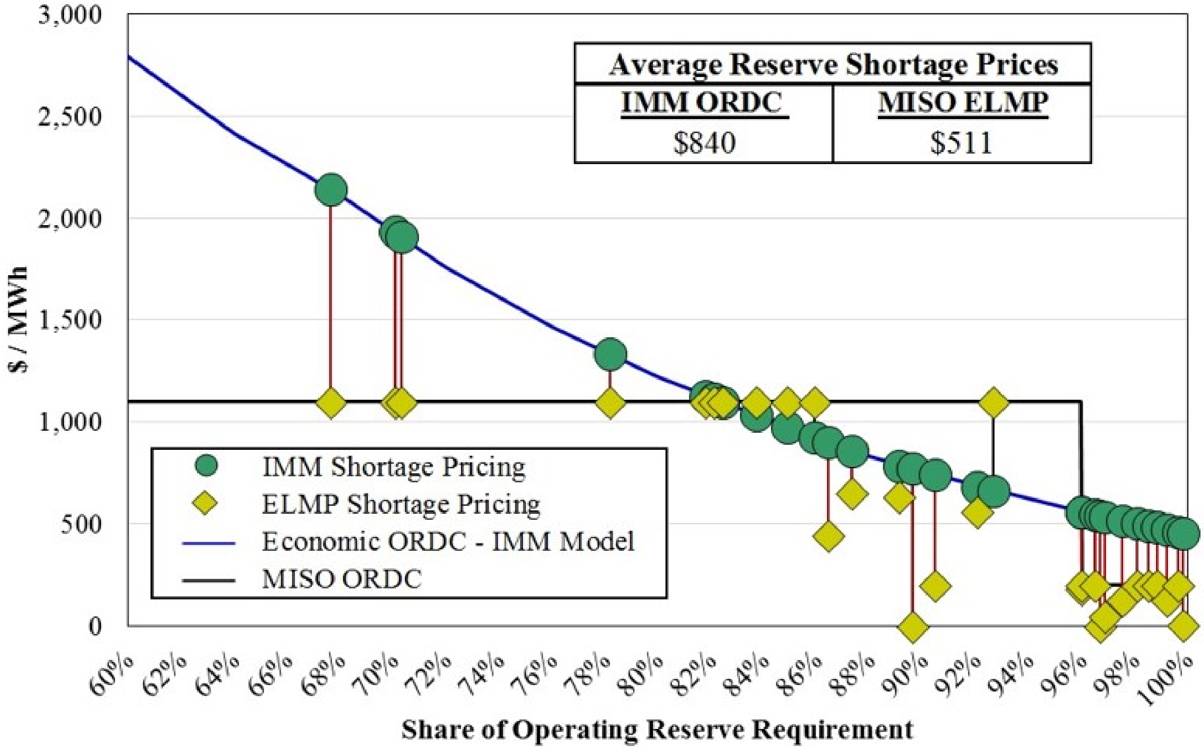
Figure 17 shows that the current curve used in MISO will set inefficiently high shortage prices under some conditions and inefficiently low shortage prices under others. The sharp increase in the curve at 96 percent of MISO's reserve requirement leads to excessive price volatility at low shortage levels. 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 2017. 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 2017.

20 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
2017



In 2017, MISO experienced a total of 32 operating reserve shortages. In nearly 50 percent of the shortages, ELMP artificially depressed the shortage prices, and in multiple instances, the ELMP model eliminated the shortage entirely. 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.

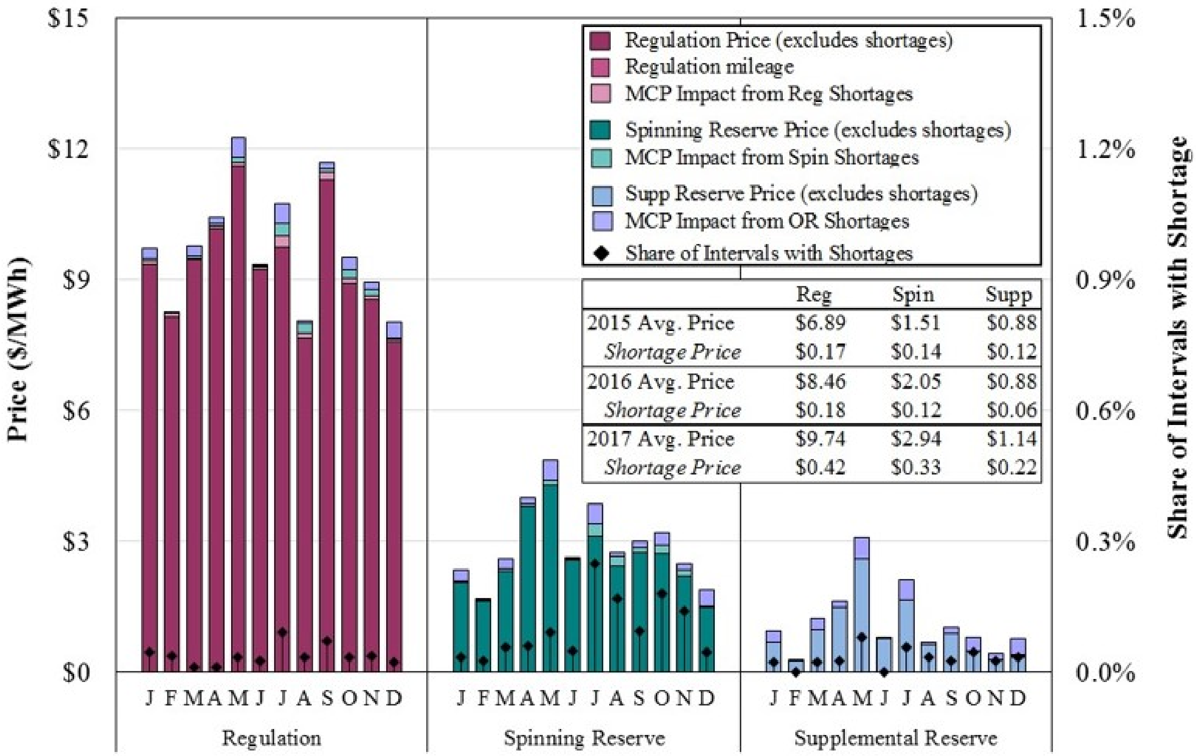
D. Ancillary Services Markets

Since their inception in 2009, jointly-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 2017, 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.[21]

The supplemental reserves contribute to meeting the market-wide operating reserve requirement (the only requirement supplemental reserves can satisfy). Spinning reserves can satisfy the operating reserve requirement, so the spinning reserve price will include a component for the operating reserve shortages. In other words, a higher-quality product will be priced to reflect the marginal cost of meeting that product plus the shortage price of any lower-quality product it is simultaneously satisfying. 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.

Figure 19: Real-Time ASM Prices and Shortage Frequency
2017



	Reg	Spin	Supp
2015 Avg. Price	$6.89	$1.51	$0.88
Shortage Price	$0.17	$0.14	$0.12
2016 Avg. Price	$8.46	$2.05	$0.88
Shortage Price	$0.18	$0.12	$0.06
2017 Avg. Price	$9.74	$2.94	$1.14
Shortage Price	$0.42	$0.33	$0.22

Monthly average clearing prices for spinning and supplemental reserves rose substantially in 2017, largely attributable to the increase in natural gas prices in the first half of the year relative

21 The demand curve for regulation, which is indexed to natural gas prices, averaged $162.77 per MWh in 2017. 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 introduced a new Operating Reserve Demand Curve in May 2013 that prices the first four percent of a total operating reserve shortage at $200 per MWh. More significant shortages are priced from $1,100 to $3,500 per MWh, depending on their severity.

to 2016 and the expansion of ELMP in May, but prices remain reasonable. The most significant increase was the average price for spinning reserves that increased 43 percent over 2016.

On April 1, 2017, high clearing prices for spinning and contingency reserves in Zone 6 prompted MISO to examine the procurement of operating reserves.[22] After a review of the existing process that forecasts zonal reserve requirements three days in advance, MISO concluded the forecasts were inaccurate and producing outcomes inconsistent with the day-ahead and real-time markets. MISO sought and received a Tariff waiver in late 2017 to correct for this flaw.

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 that the total market revenue a generator receives when committed by MISO 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.

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

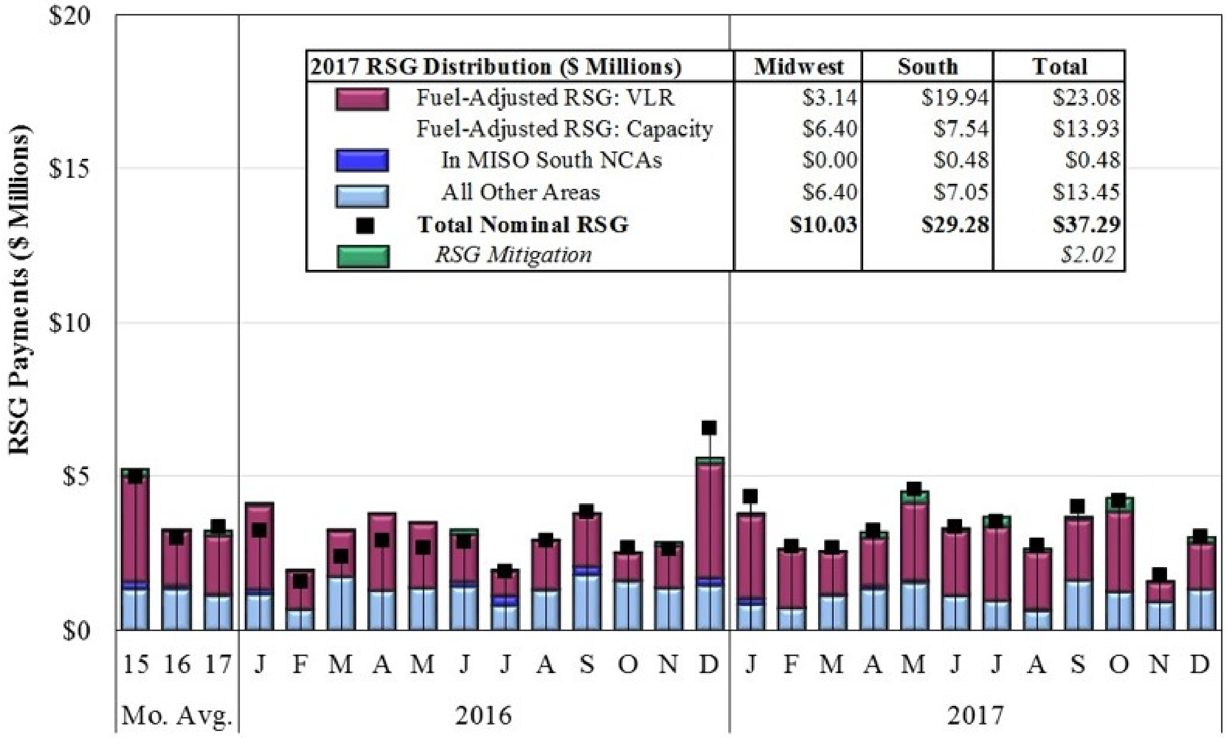
Figure 20 shows monthly day-ahead RSG payments by the underlying cause of the RSG. Most RSG payments for Voltage and Local Reliability (VLR) are made in the day-ahead market because most VLR commitments are made before or during the day-ahead market. Because fuel prices have considerable influence over suppliers' production costs, the figures show RSG payments in both nominal and fuel-adjusted terms.[23] The maroon bars show the RSG paid to

22 See the MISO presentation here: https://cdn.misoenergy.org/20170713%20MSC%20Item%2004%20Spinning%20Reserve%20Pricing%20Event75021.pdf.

23 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.

units started before the day-ahead for VLR, while the royal blue bars show amounts we believe were paid to units likely committed for VLR by the day-ahead model but not designated as VLR.

Figure 20: Day-Ahead RSG Payments
2016–2017

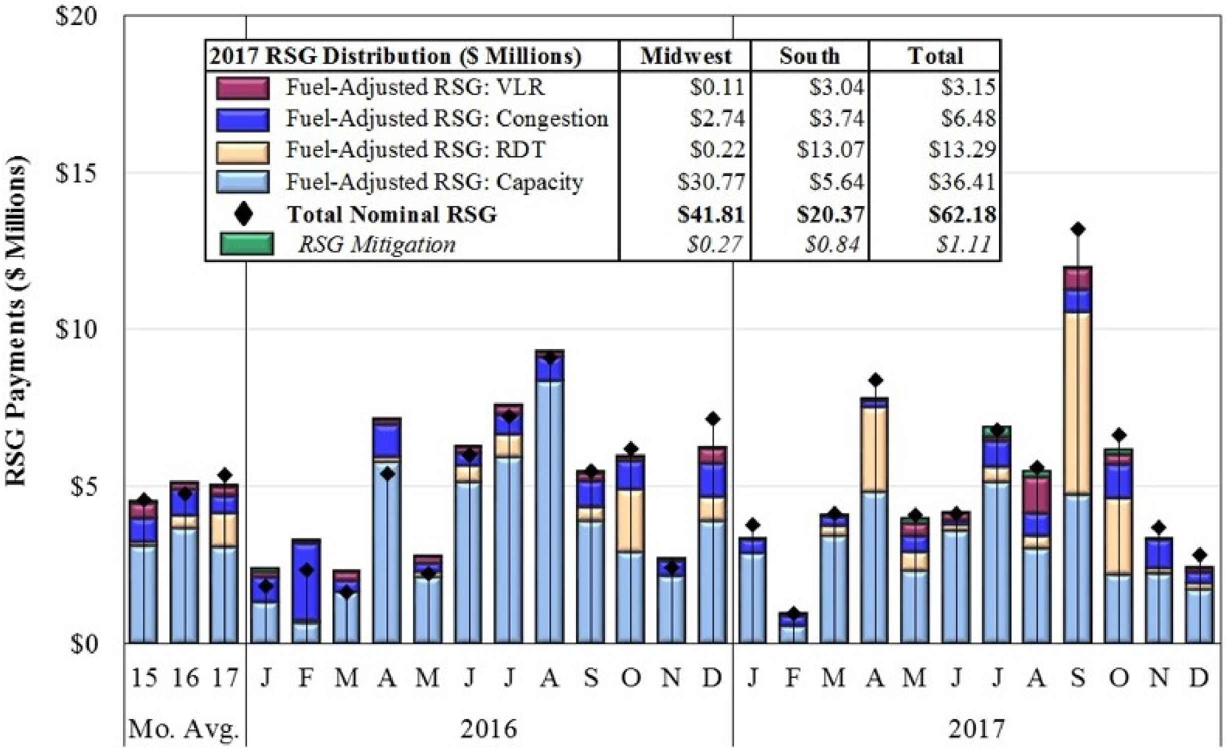


Nominal day-ahead RSG costs increased by 11 percent to $3.4 million per month in 2017. However, fuel-adjusted day-ahead RSG costs fell by five percent during the same period because fuel prices were significantly higher in the first half of 2017 relative to 2016.

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, more than 50 percent of all day-ahead RSG payments were caused by VLR needs in the South. To reduce these costs further, we have recommended that MISO implement a 30-minute reserve product in the day-ahead and real-time that will satisfy this recommendation.

Figure 21 shows the same monthly RSG payments from the real-time market. This figure shows that nominal average real-time RSG payments rose 13 percent in 2017, primarily because of higher fuel prices in the first half of the year. Adjusting for changes in fuel prices, real-time RSG *decreased* by two percent in 2017.

Figure 21: Real-Time RSG Payments
2016–2017



The figure also shows that RSG payments associated with the RDT was substantial in 2017. High outage rates combined with unseasonably warm temperatures in early April and late in September contributed to many out-of-merit commitments in the South subregion to manage potential flows across the RDT constraint.[24] We have several concerns about these commitments:

- These commitments were treated as capacity commitments even though they were made to maintain sufficient reserves in the South to protect against exceeding the RDT limit.
- RDT commitments are made outside of the market because MISO's markets do not model subregional capacity requirements or associated reserve requirements.
- Even though these commitments are made to satisfy subregional reliability requirements, the associated RSG costs are socialized across the entire MISO footprint.
- Suppliers currently can exercise market power and inflate these RSG payments. MISO cannot mitigate this conduct, but recently filed Tariff changes to address this issue.[25]

We have recommended that MISO implement a regional 30-minute reserve product to allow the markets to procure the resources needed to satisfy these requirements. MISO is working to

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24 In 2017, we identified a flaw in the calculations used in this process which overstated the needs for these commitments, and MISO has taken steps to correct the flaw.

25 See MISO's filing in Docket no. ER-18-1464-002.

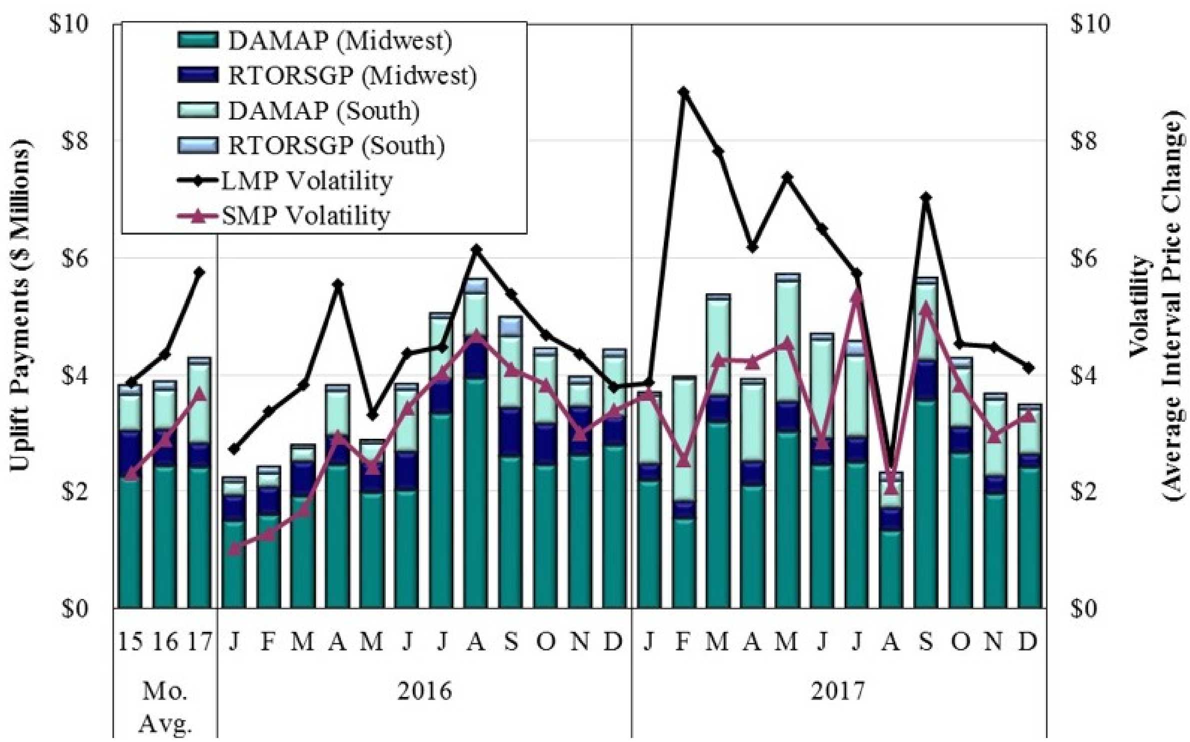
implement such a product, which is currently scheduled for implementation in late 2019. In the meantime, MISO has filed tariff changes to apply the Reserve Procurement Enhancement (RPE) to the RDT.[26] This should allow MISO's market commitments to better satisfy these needs.

Finally, MISO expanded eligibility modestly in May 2017 for fast-start units to participate in ELMP, but it continues to have only a small effect on real-time prices and real-time RSG costs. We are recommending expanding the eligibility further and proposed other changes to make ELMP 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
2016–2017



26 Id.

The figure shows that the PVMWP levels increased by 10 percent in 2017, generally because of the increased volatility in 2017. LMP volatility rose by almost one third in 2017 and spiked in February as tornadoes and severe storms in MISO South on February 7 led to multiple transmission outages. Prices at the Louisiana Hub exceeded $1,000 per MWh for three hours on this day. DAMAP made to resources in MISO South accounted for all of the increase, as RTORSGP fell slightly from 2016 levels.

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 7 shows the total DAMAP paid in 2017 subdivided by the following causes:

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

Table 7: Causes of DAMAP in 2017

Item Description	DAMAP ($ Million)	% Share
Following Instruction	$33.3	75%
SE Error	$0.4	1%
Dragging - Failing IMM New Threshold	$3.4	8%
Unjustified Wind Payments	$2.7	6%
Dragging - Not Failing IMM New Threshold	$4.9	11%
Total	$44.6	100%

Note: Excluded Hour Beginning 0 in the Analysis

The table shows that $2.7 million of the DAMAP were unjustified payments to wind resources that over-forecasted their output. These resources should not be eligible for DAMAP, but they remain eligible because of a flaw in the MISO Tariff.[27] MISO will correct this flaw when it implements its five-minute settlements, which is anticipated in late 2018.

Table 7 also shows that 19 percent of the DAMAP was paid to resources that are 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

27 The flaw was in the Schedule 27 payment formula, which is intended to cause resources dispatched at their EcoMax to be ineligible for DAMAP, but was specified incorrectly for wind resources.

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, MISO plans to reform its calculation of the DAMAP and RTORSGP to substantially reduce payments that are due to poor dispatch performance. MISO plans to jointly improve uninstructed deviation thresholds, which should further reduce the unjustified DAMAP.

Five-Minute Settlement

MISO produces new dispatch signals and prices every five minutes but settles with generators and physical schedulers on an hourly basis using an average of the five-minute prices. This can create inconsistencies between the dispatch signals and the hourly prices that subsequently create incentives for generators to not follow the dispatch signal or incentives to be inflexible. To address these inconsistencies, MISO introduced the PVMWPs described above. However, the PVMWPs are a poor substitute for a true five-minute settlement where each generator, importer, or exporter would settle based on the actual value of energy corresponding with its production or transactions in each five-minute interval. In 2017, we continued to find that the lack of five-minute settlements continued to harm resources that are controllable and perform well. FERC supported our recommendation in this area, issuing a Rule in 2016 requiring MISO to transition to a five-minute settlement, which MISO plans to implement in the third quarter of 2018.

F. 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 assesses 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.[28] The purpose of the tolerance band is to permit deviations to balance the physical limitations of generators with MISO's need for units to accurately follow dispatch instructions. MISO's criteria for identifying deviations are significantly more lenient than most other RTOs' and contribute to poor performance by some suppliers. In addition to this settlement threshold, MISO's real-time operators are responsible for identifying resources that are responding poorly (or not at all) to MISO's dispatch.

Figure 23 shows the size and frequency of two types of net deviations:

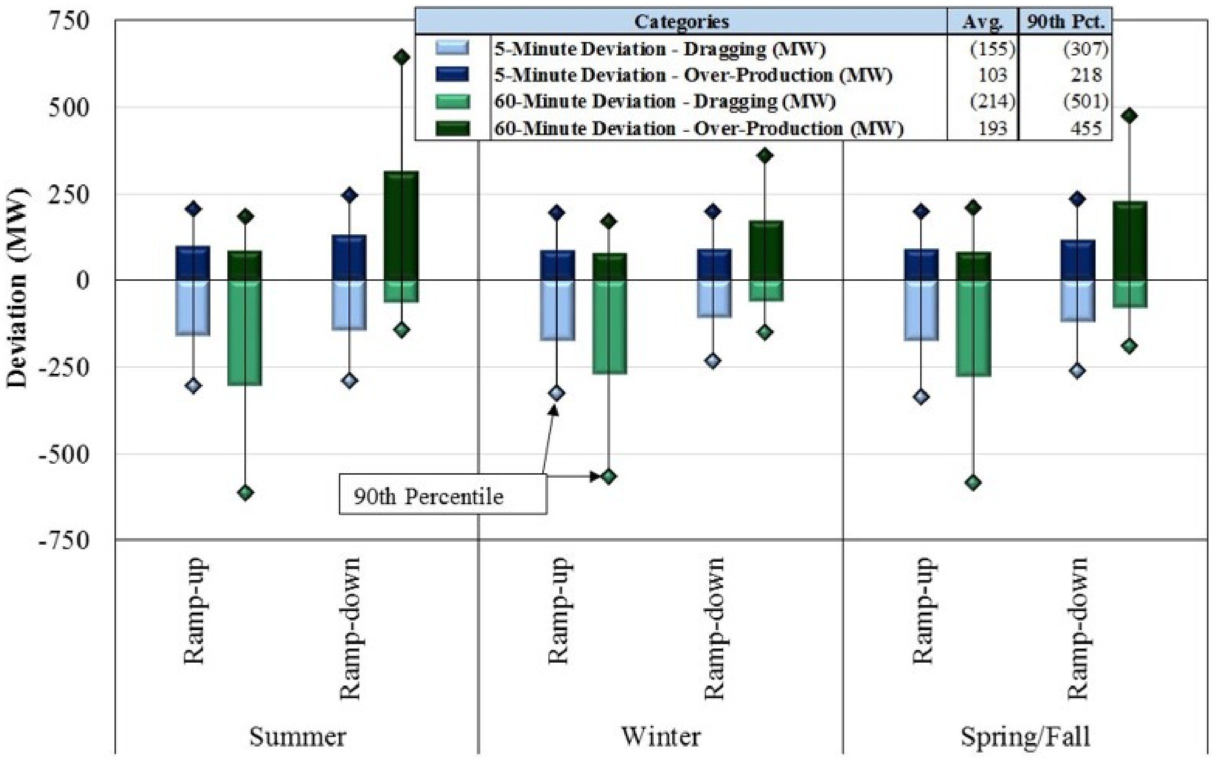
- <u>Five-minute deviation</u> is the difference between MISO's dispatch instructions and the generators' responses in each interval.
- <u>60-minute deviation</u> is the effect over 60 minutes of generators not following MISO's dispatch instructions.

The methodology for calculating the 60-minute deviation is described in more detail in Section V of the Analytic Appendix, but it is essentially the difference between energy the generator is

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

actually producing and what it would be producing had it followed MISO's dispatch instructions over the prior 60 minutes. The figure shows these results by season in ramp-up and ramp-down hours when the impact of deviations are most severe on both pricing and reliability.

Figure 23: Average Five-Minute and Sixty-Minute Net Deviations
2017



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 200 MW (almost 10 percent of MISO 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.

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 that it is very important that MISO improve its settlement rules and operating procedures for addressing poor generator performance. Therefore, we have recommended two changes to:

- Improve the tolerance bands for uninstructed deviations (i.e., Deficient and Excessive Energy) to make them more effective at identifying units that are not following dispatch.
- Modify the PVMWP rules to adjust the payment based on the generators' performance.

We have worked with MISO and its stakeholders to develop a proposal that will address the first two changes that we expect will be filed in the 3rd quarter of 2018. These changes will improve participants' incentives to perform well and follow MISO's dispatch instructions, while allowing MISO operators and its dispatch models to make better dispatch and commitment decisions.

In early 2018, MISO implemented a new procedure to receive alerts from the IMM identifying resources with large 60-minute dragging deviations that may be derated. This will allow MISO to contact the generator and place it off-control when warranted.

G. 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:

- Generator outages occur that are not yet recognized by UDS;
- Generator deviations (producing more or less than MISO's dispatch instructions);
- Wind output is over or under-forecasted in aggregate; or
- Operators believe the short-term load forecast is over or under-forecasted;

The analysis shows that larger changes in offset values are associated with increased price volatility. This 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 effects:

- Decreases in the offset by 600 MW or more corresponds to an average decrease in SMP of more than $40; and
- Increases in offsets by 600 MW or more corresponds to an average increase in the SMP of nearly $50.

We monitor offset values because large changes, although infrequent, can sometimes contribute to price spikes or mute legitimate shortage pricing. Unfortunately, the reasons for MISO's offset choices are not well documented and the offset values used could be improved. Hence, we encourage MISO to improve the tool used to recommend offset values and the logging of the offset choices.

H. Evaluation of Dispatch Operations: Commitment Classifications

When MISO operators make out-of-market commitments, it classifies them into four main categories: transmission-constraint management (TXX), voltage and local reliability (VLR), capacity, and RDT management. These commitment designations affect how the associated RSG costs are allocated and whether the suppliers' offers are subject to market power mitigation (i.e., only TXX and VLR commitments). The costs of TXX and VLR commitments are allocated to local deviations and local load via the CMC rate and VLR allocations, respectively. Capacity and RDT commitments are not subject to mitigation and their costs are allocated market wide.

Hence, it is essential that the commitments be classified accurately, which we evaluate in this section. Because capacity commitments should generally be the lowest-cost available resources market-wide, we look for cases where a much higher-cost resource is committed than a large number of lower-cost uncommitted resources. This signals that the resource was likely committed to resolve a locational or reliability issue.

Lower-cost units were available for nine percent of commitments that were made for capacity needs. However, these cases accounted for 19 percent of all RSG paid for capacity needs in 2017, or over $5 million of RSG in total. These results suggest that MISO may sometimes be misclassifying capacity commitments that were actually made for other reasons. Therefore, we recommend that MISO develop a process to correct commitment codes that may be entered incorrectly in order to allocate the associated costs accurately and apply market power mitigation correctly.

I. New Operating Reserve Products

MISO has incurred substantial RSG in a limited number of areas to satisfy VLR requirements. These costs arise as MISO commits additional local resources to prepare the area to withstand both the largest potential contingency in the area as well as the second largest contingency. These requirements are attributable to the fact that some areas do not have resources that can start within 30 minutes to restore the lost reserves after the first contingency. In essence, MISO is committing resources to hold reserves on online resources. For the same reason, MISO is also committing resources to satisfy capacity requirements in the Midwest and South subregions to ensure that it can withstand the largest subregional contingency without exceeding the RDT.

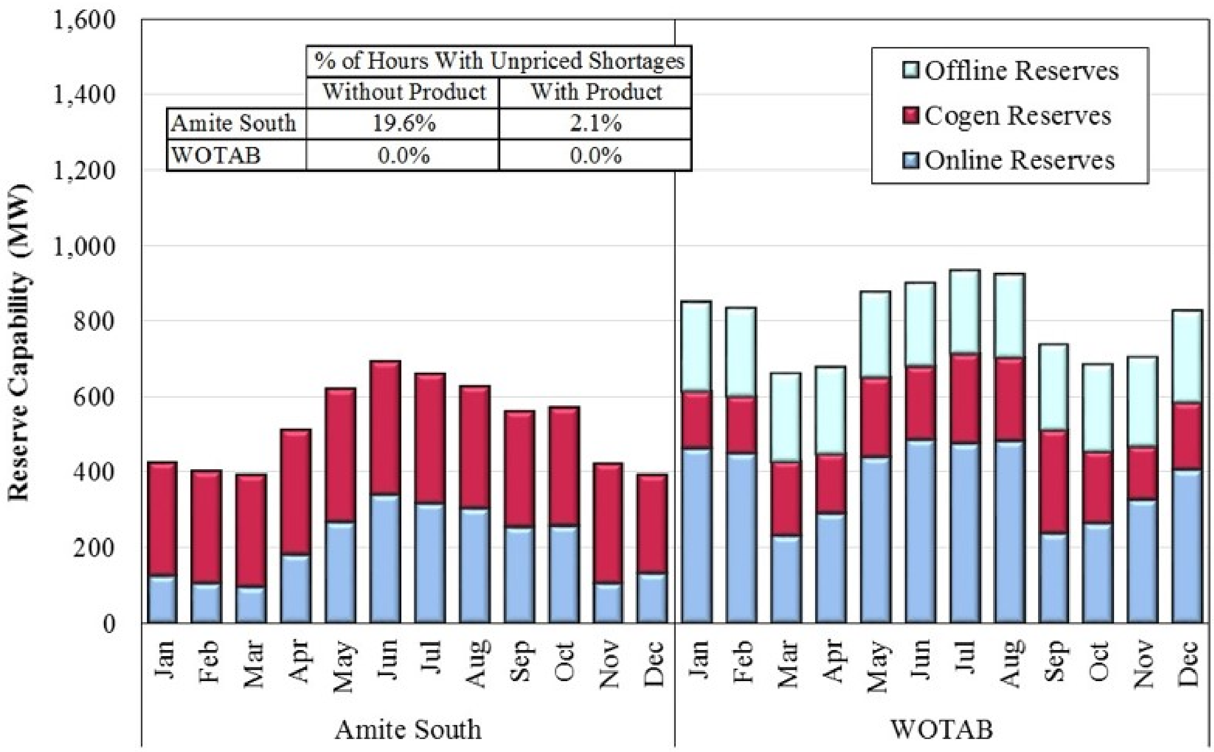
To address both of these needs, we recommend that MISO create a local 30-minute reserve product in these areas so that these requirements can be priced and procured through MISO's markets, rather than through out-of-market commitments that result in uplift. Defining such a product for the subregions would likely alter the resource commitments in the day-ahead market to satisfy these needs at lower costs. It will also allow the markets to price shortages when regional resources are insufficient to satisfy the full reserve requirement.

In the both areas, this would provide market signals to build fast-starting units or other resources that can satisfy the VLR or subregional needs at a much lower cost (because they can satisfy the requirements while offline). Although this would not eliminate the need for VLR or RDT commitments, it would significantly reduce the amount of RSG they generate.

Additionally, defining such a product for the VLR areas may allow other resources that currently exist within the load pockets to satisfy the VLR requirements. We have conducted an analysis to quantify all of the 30-minute reserve capability that is currently available to respond to a system contingency in the South load pockets. We also estimated the percentage of unpriced shortages in 2017 that would have occurred if the 30-minute reserve product were to exist.

Figure 24: 30-Minute Reserve Capability Potential Savings

South Load Pockets, 2017



This is analysis showed:

- More than 600 MW of 30-minute reserve capability existed in Amite South during the summer and more than 900 MW in WOTAB.
- Roughly half of these reserves are supplied by two categories of resources that do not have a means to provide these reserves (cogeneration resources and offline peaking resources).
- MISO could have realized more than $2 million in RSG savings in 2017 if a 30-minute reserve product had been in place in the Amite South MISO load pocket and all of the resources we identified were capable of supplying it.
- Additional savings are available in WOTAB and the South (related to the RDT).

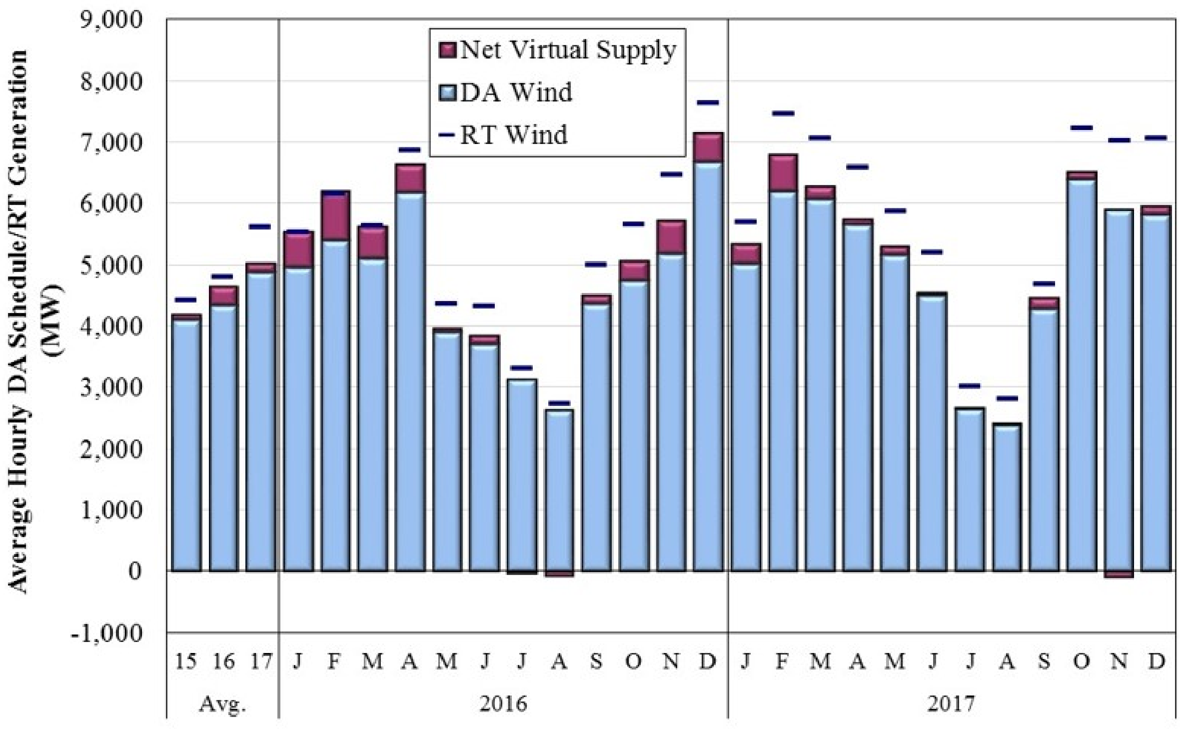
J. Wind Generation

Installed wind capacity exceeds 17 GW and accounted for eight percent of generation in 2017. In 2017, 288 MW of wind capacity entered MISO, down from 1.4 GW in 2016. However, we expect development to continue as long as tax incentives exist.[29] 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 25 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. The virtual supply tends to compensate for the fact that wind suppliers in aggregate do not schedule their full output in the day-ahead market, but this response was lower in 2017.

Figure 25: Day-Ahead and Real-Time Wind Generation
2016–2017



29 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 relatively high capacity factors of wind units in MISO, most new wind suppliers chose the PTC. Wind units that were under construction by 2016 receive the full credit for 10 years, while the credit falls 20 percent each year for units that begin construction from 2017 through 2019.

Real-time wind generation in MISO increased 17 percent in 2017 to 5.6 GW per hour. MISO set several all-time wind records in 2017, the last of which was set in December at 14.7 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 25 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. Underscheduling of wind averaged 806 MW per hour and exceeded 1,200 MW in two months. The figure shows that virtual supply at or near wind locations often plays a key role in arbitraging the wind scheduling inconsistency.

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 updating its processes and products to address these challenges, including the introduction of the ramp product in 2016.

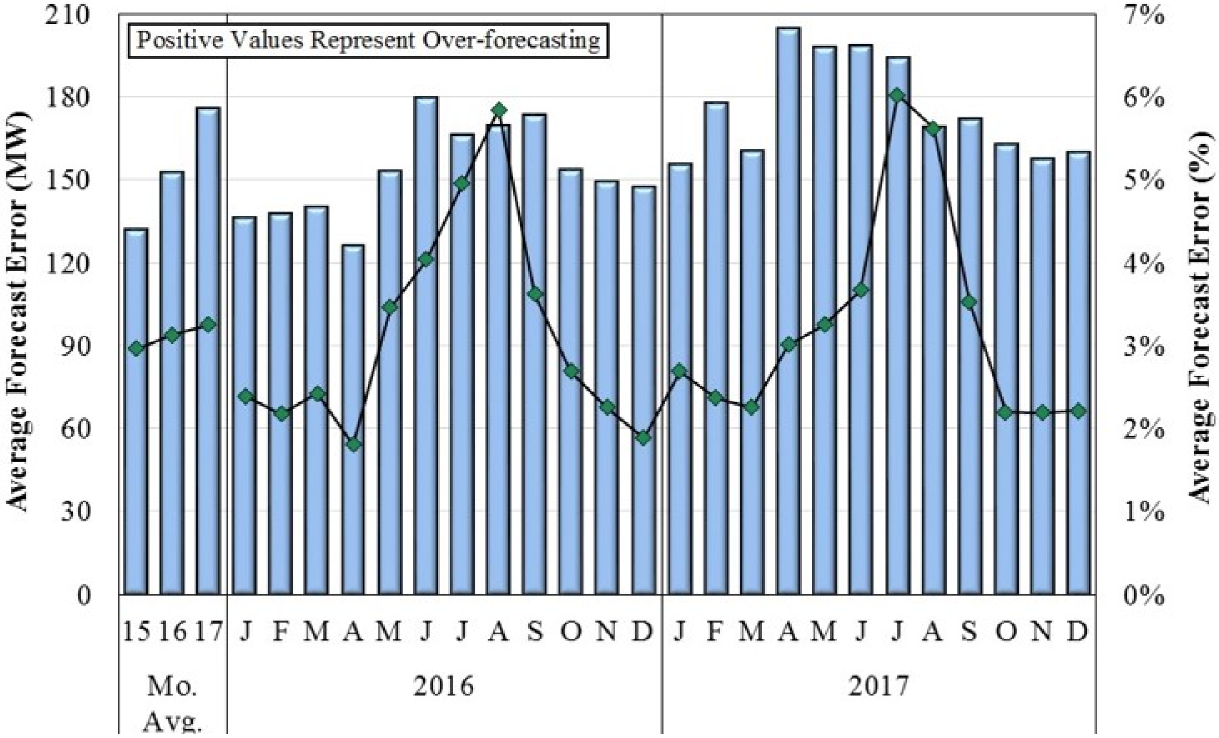
The concentration of the wind resources in the western areas of MISO's system has also created growing network congestion in some periods that can be difficult to manage. MISO's Dispatchable Intermittent Resource (DIR) type has been essential in allowing MISO to manage this volatility. DIR participation 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). DIR has almost entirely eliminated manual curtailments as a means to manage congestion caused by wind output or over-generation conditions.

Wind Forecasting

In 2016, 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 26 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 2016 and 2017.

Figure 26 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 contribute to wind over-forecasting: DAMAP and uninstructed deviation settlements.

Figure 26: Generation Wind Over-Forecasting Levels
2016–2017



DAMAP Tariff Flaw. MISO's DAMAP settlements formula allows existing DIR wind resources to receive unintended DAMAP when they are dispatched at their economic maximum. Resources were only intended to receive DAMAP when they are dispatched below their economic maximum. However, the Tariff was written in a manner that did not recognize that the economic maximum would be able to change every five minutes, as it can for DIR wind units. MISO's five-minute settlement reforms scheduled for the third quarter of 2018 address this flaw.

Biased Uninstructed Deviation Settlements. Wind resources face asymmetric costs for uninstructed deviations associated with forecast errors. One reason for this is that generators are paid the lower of their offer price or zero for excess energy. Because of PTCs, wind resources generally submit negative energy offers, so the penalty for excessive energy is much larger than for other resource types (the penalty is the difference between the LMP and their offer price). Conversely, wind units are only deficient when the resource's actual generating capability is less than its forecast, a situation that does not cause them to forego any profit margin.[30]

30 In fact, wind resources will generally receive DAMAP that will provide this profit margin on the energy they are unable to produce.

Aligning the excessive and deficient energy penalties (by reducing the explicit excessive energy penalty or increasing the costs of deficient energy) would help balance the incentives and promote less-biased forecasts. MISO intends to propose some changes in this area when it files the improvements to its uninstructed deviation thresholds and PVMWP rules.

MISO should also consider other approaches to promote unbiased wind resource forecasts, including adopting excess energy thresholds for wind resources that recognize the potential for congestion to arise if wind resources over-produce.[31] MISO could provide wind resources a "not-too-exceed" limit that would allow wind resources to exceed their dispatch instructions up to a reliable maximum level. This solution would maximize the economic value of these low-cost resources, by allowing them to produce more than their forecasts, while mitigating reliability concerns associated with wind output volatility.

Finally, 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.

31 ISO New England employs a similar approach.

VI. Transmission Congestion and FTR Markets

To avoid overloading transmission constraints, MISO's markets manage flows over its 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.[32] The congestion component of the LMPs can vary substantially across the system, raising LMPs in "congested" areas where increased generation would relieve the constraints and lowering LMPs in areas where generation increases the flows over 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 2017

We separately 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 is actually occurring as MISO dispatches its system. Figure 27 shows the monthly real-time congestion values in 2016 and 2017.

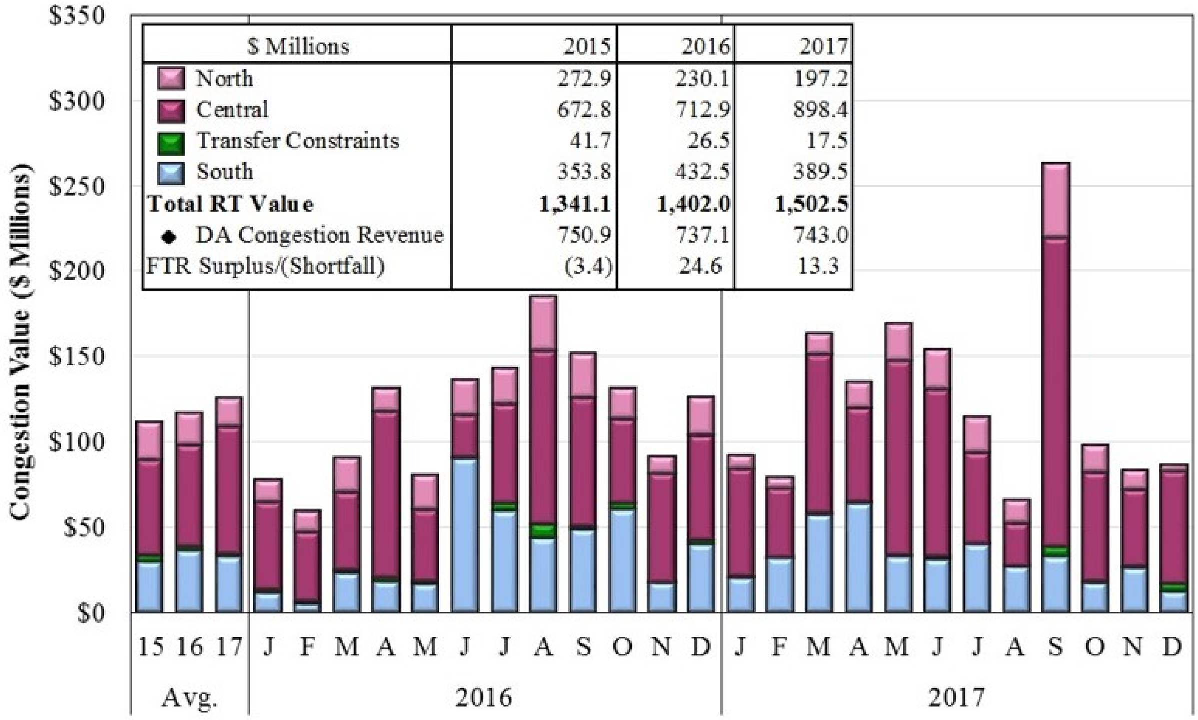
The value of real-time congestion increased by 7.2 percent from last year to $1.5 billion. Natural gas prices increased in the first half of 2017, which tends to increase congestion costs because natural gas-fired units are generally dispatched to manage the power flows over binding constraints. Additionally, these factors contributed to higher real-time congestion:

- In the winter, a single market-to-market constraint generated $40 million in real-time congestion. It was difficult to manage because it was dominated by PJM. On February 7, MISO transferred the constraint to PJM, which significantly reduced this congestion.
- Severe storms in MISO South on February 7 led to $19 million of real-time congestion, as tornadoes caused multiple transmission outages.
- In September, real-time congestion increased 73 percent over September 2016 to a total of $262 million because of high loads and key generation and transmission outages.
- In September and October, MISO incurred $137 million in congestion on uncoordinated constraints that likely should have been defined as market-to-market with PJM or SPP. Almost all of the constraints that resulted in this congestion were not defined as market-to-market constraints because MISO failed to ask SPP or PJM to perform the tests.

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

- Planned and forced generation and transmission outages (including outages for construction of Multi-Value Projects) contributed to severe transitory congestion.

Figure 27: Value of Real-Time Congestion and Payments to FTRs
2016–2017



During the summer months, the value of real-time congestion decreased 28 percent compared to 2016 because summer temperatures were milder and load was lower. Additionally, transmission upgrades provided more resource flexibility for the VLR areas in MISO South.

The real-time congestion that occurred in 2017 and prior years is higher than optimal because several key issues continue to prevent fully efficient management of MISO's congestion. These issues are each discussed in this section and include:

- Procedural issues in defining and activating market-to-market constraints;
- Inefficient congestion on constraints affected by resources pseudo-tied to PJM;
- Congestion caused by TLR response on external constraints; and
- Congestion caused by the lack of coordination of transmission and generation outages.

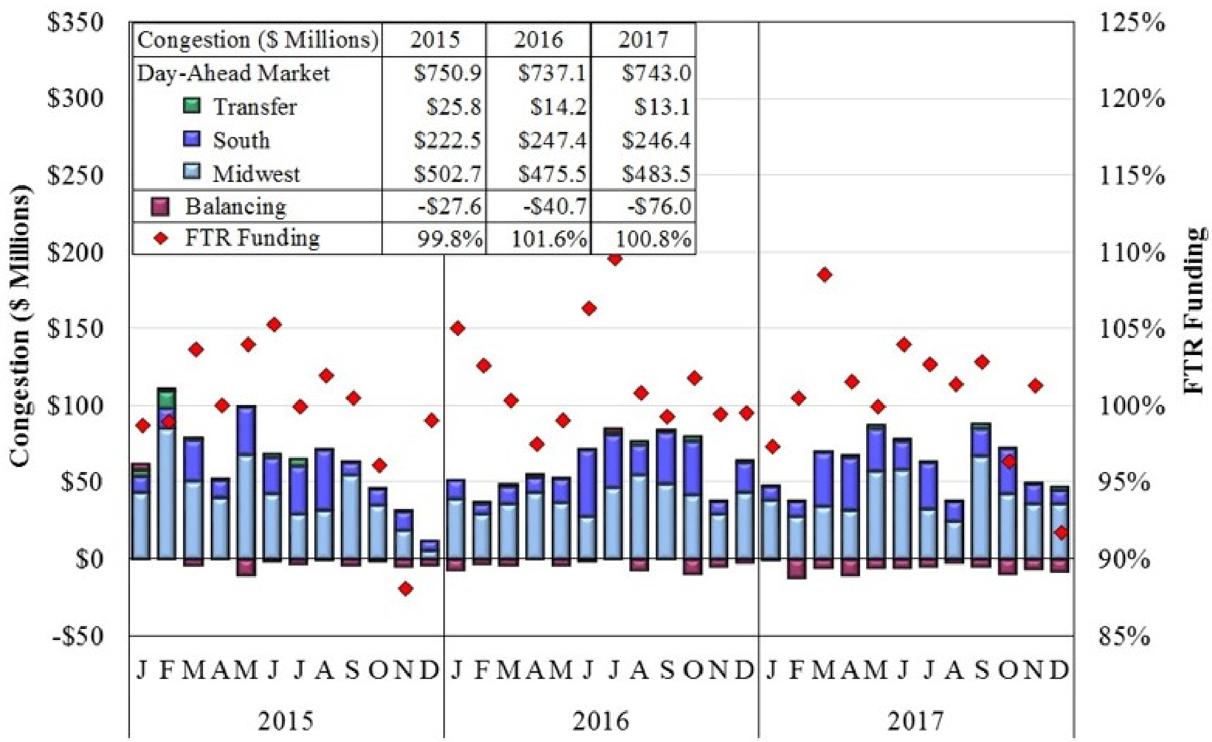
B. Day-Ahead Congestion Costs and FTR Funding in 2017

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 28 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 2015 to 2017.

Figure 28: Day-Ahead and Balancing Congestion and FTR Funding
2015–2017



Note: Funding surplus or shortfall may be more or less than the difference between day-ahead congestion and obligations to FTR holders because it includes residual costs and revenues from the FTR auctions, such as the net settlements in the monthly FTR market.

Day-Ahead Congestion Costs

Day-ahead congestion costs rose one percent to $743 million in 2017. Mild weather conditions over the summer reduced congestion on transfer constraints. However, higher gas prices in the first half of the year and significant outages in the spring and fall led to higher congestion in the shoulder seasons. 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 (which they do not pay for).

Planned and forced generation and transmission outages in MISO South led to operational challenges on several occasions throughout the year. In the spring, forced outages and severe weather occurred while a third of all capacity in MISO South was on outage. This led to several episodes of acute congestion.

FTR Shortfalls

Over- and underfunding is caused by discrepancies in the modeling of the annual and monthly auctions compared to the transmission constraints and outages that actually occur. Congestion revenues exceeded FTR obligations by $13.3 million – a surplus of roughly one percent. External constraints have tended to be underfunded because they are not fully anticipated and modeled in the FTR markets – SPP constraints, for example, were underfunded by 47 percent in 2017. In contrast, the transfer constraints 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 the opposite direction of the FTRs.

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 LBA.[33] The transmission constraints in five of the LBA areas were underfunded by 20 percent or more. This potentially raises concerns regarding the incentive to fully report outages because the underfunding costs are socialized to all MISO areas.

Underestimated loop flows also account for the some of the shortfalls because loop flows across the MISO system reduce the capability MISO can utilize in the day-ahead and real-time markets. In 2017, these factors were more than offset by FTR surpluses produced on constraints whose capability were not fully sold in the FTR auctions.

Balancing Congestion

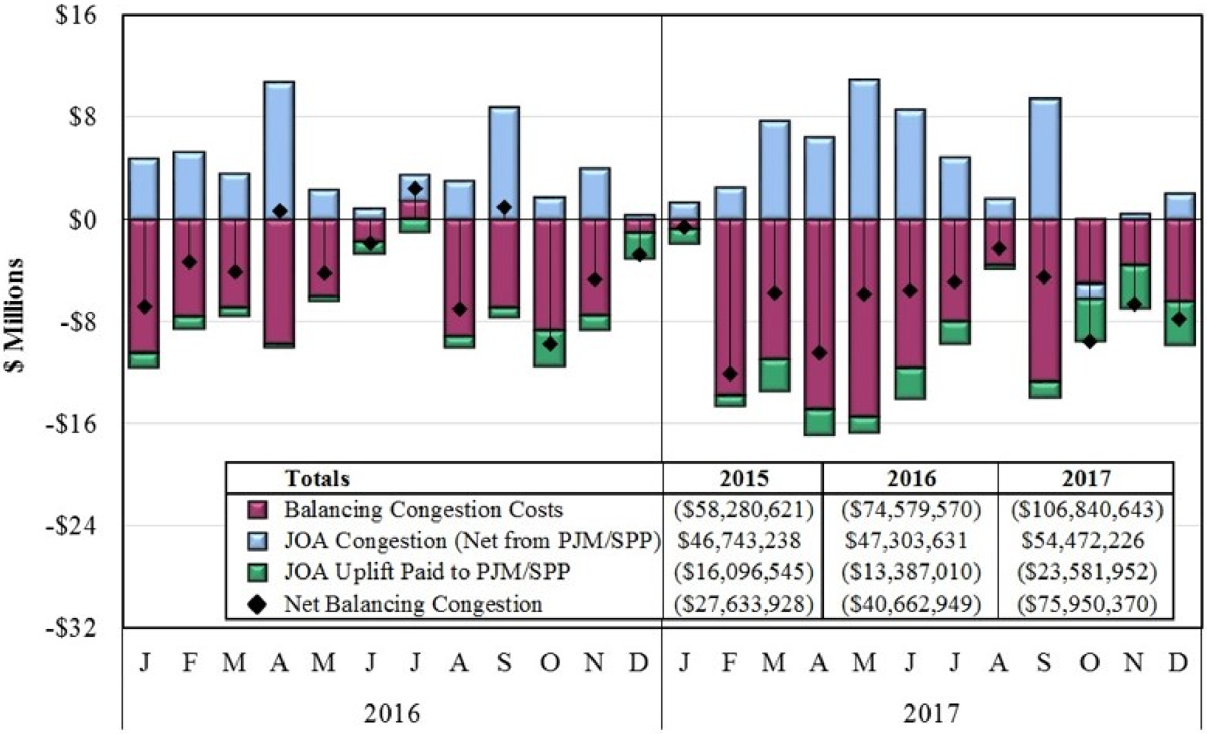
Balancing congestion shortfalls (negative balancing congestion revenue) occurs when the transmission capability available in real time is less than the capability scheduled in the day-ahead market. In other words, the costs of redispatching generation to manage constraints in real time to reduce flows that were scheduled in the day-ahead market are negative balancing

33 See Figure A91 in the Analytic Appendix.

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 revenue typically indicate real-time transmission outages, derates, or loop flow that were not 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 29 shows the monthly balancing congestion costs incurred by MISO over the past two years.

Figure 29: Balancing Congestion Costs
2015–2017



Totals	2015	2016	2017
Balancing Congestion Costs	($58,280,621)	($74,579,570)	($106,840,643)
JOA Congestion (Net from PJM/SPP)	$46,743,238	$47,303,631	$54,472,226
JOA Uplift Paid to PJM/SPP	($16,096,545)	($13,387,010)	($23,581,952)
Net Balancing Congestion	($27,633,928)	($40,662,949)	($75,950,370)

Net balancing congestion costs increased 87 percent in 2017 to total nearly $76 million, excluding JOA uplift of $23.6 million. JOA uplift payments are made to pay for market flows on coordinated market-to-market constraints. MISO had balancing congestion shortfalls throughout 2017. These levels of balancing congestion costs indicate that consistency between the day-ahead and real-time market models could be improved. $11 million of the balancing congestion was caused by tornadoes that tripped multiple high voltage transmission lines in MISO South on February 7. High net balancing congestion in 2017 was also affected by significant congestion on SPP constraints that were not fully anticipated in the day-ahead market and resulted in $26.1 million in congestion.

Coordinating Outages that Cause Congestion

Generators take planned outages to conduct periodic maintenance to evaluate or diagnose operating issues, and to upgrade or repair various systems. Similarly, transmission operators conduct periodic planned maintenance on transmission facilities, which generally reduces the transmission capability of the system. MISO evaluates the reliability effects of the planned outages, including conducting contingency and stability studies on planned outages.

Participants tend to consolidate planned outages in shoulder months, assuming that the opportunity costs of taking outages is lower because load is mild and prices are relatively low. However, this is not always true. Different participants may schedule multiple 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 will likely have substantial economic effects. 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 2016 and 2017 that occurred on 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
2016–2017

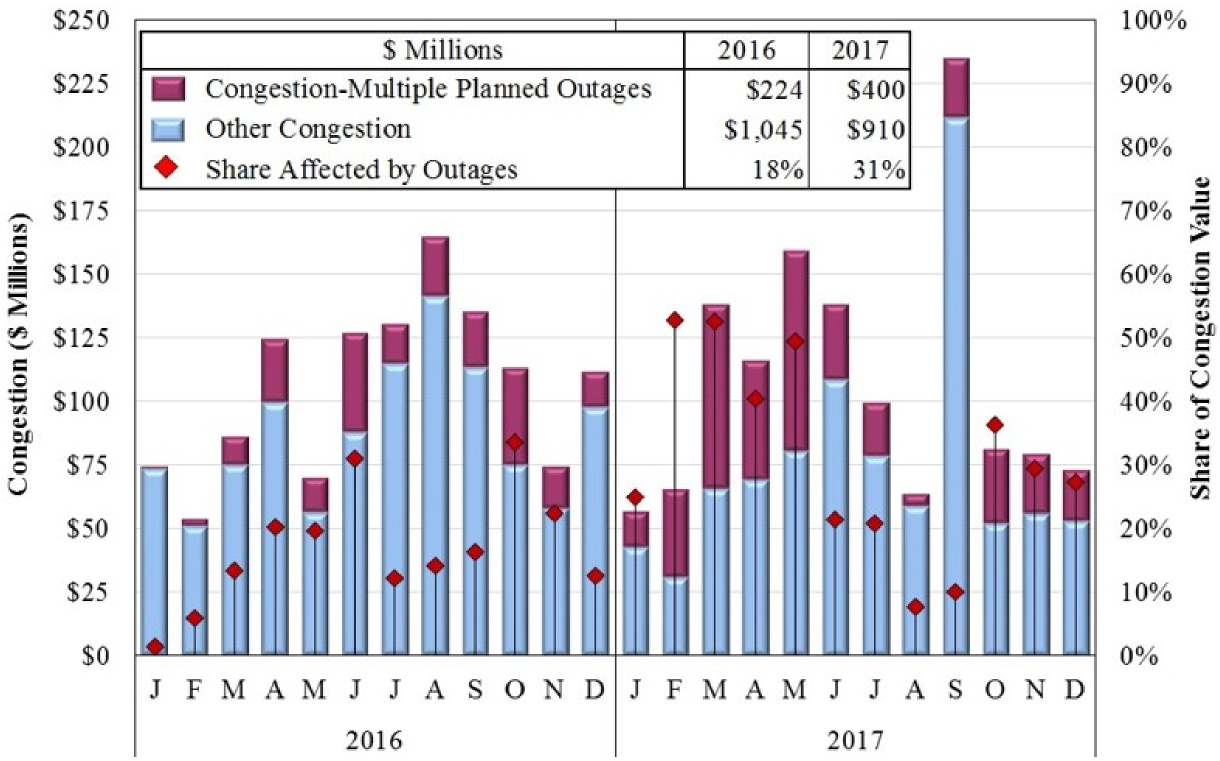


Figure 30 shows that 31 percent of the total real-time congestion in 2017 – $400 million – was attributable to multiple planned generation outages. In all months that we analyzed, planned outages caused significant congestion, including more than 70 percent of all congestion in March, and more than 40 percent in February and May. 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

A 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:

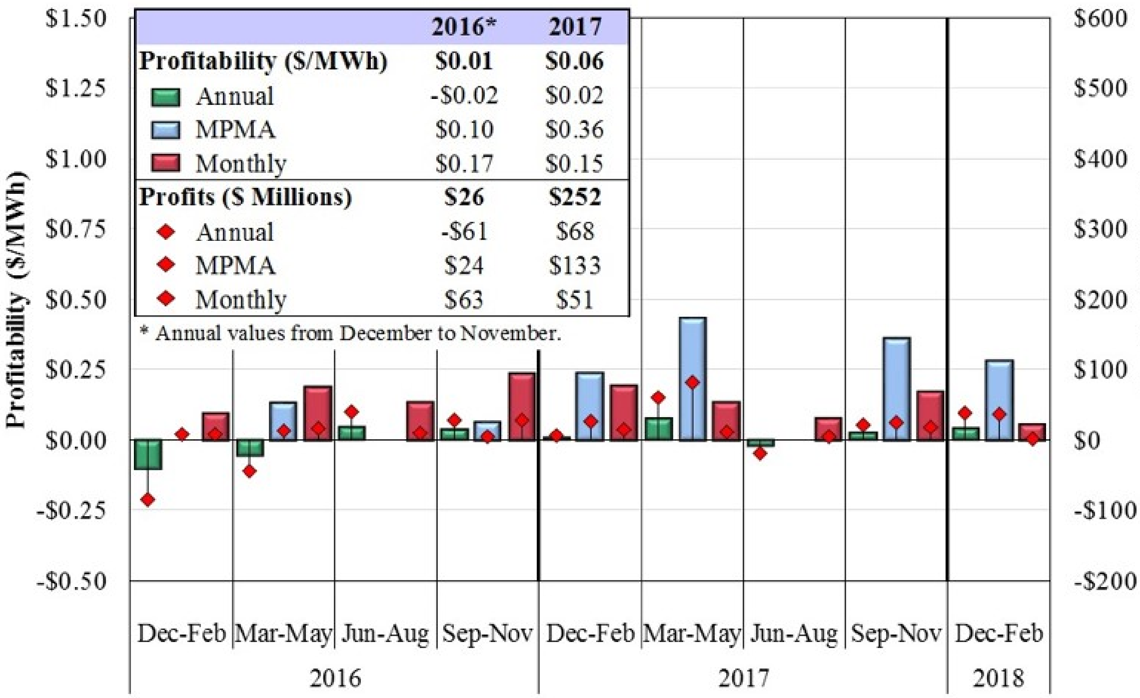
- An annual auction from June to May that includes seasonal and peak/off-peak resolution of bids, offers, and awards; and
- A Multi-Period Monthly Auction (MPMA) that yields monthly and seasonal peak/off-peak awards. The MPMA facilitates FTR trading for future periods in the planning year.

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 slightly profitable as losses in the third quarter of 2017 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 2016-2017 auction year, large day-ahead congestion values overwhelmed the impacts of that behavior.

Figure 31: FTR Profits and Profitability
2016–2017



FTR Profitability in the MPMA. Figure 31 shows that the FTRs purchased in the MPMA and prompt month have been very profitable. 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. In 2017, however, multiple episodes of severe congestion led to a larger divergence between the FTR clearing prices and the day-ahead 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.[34]

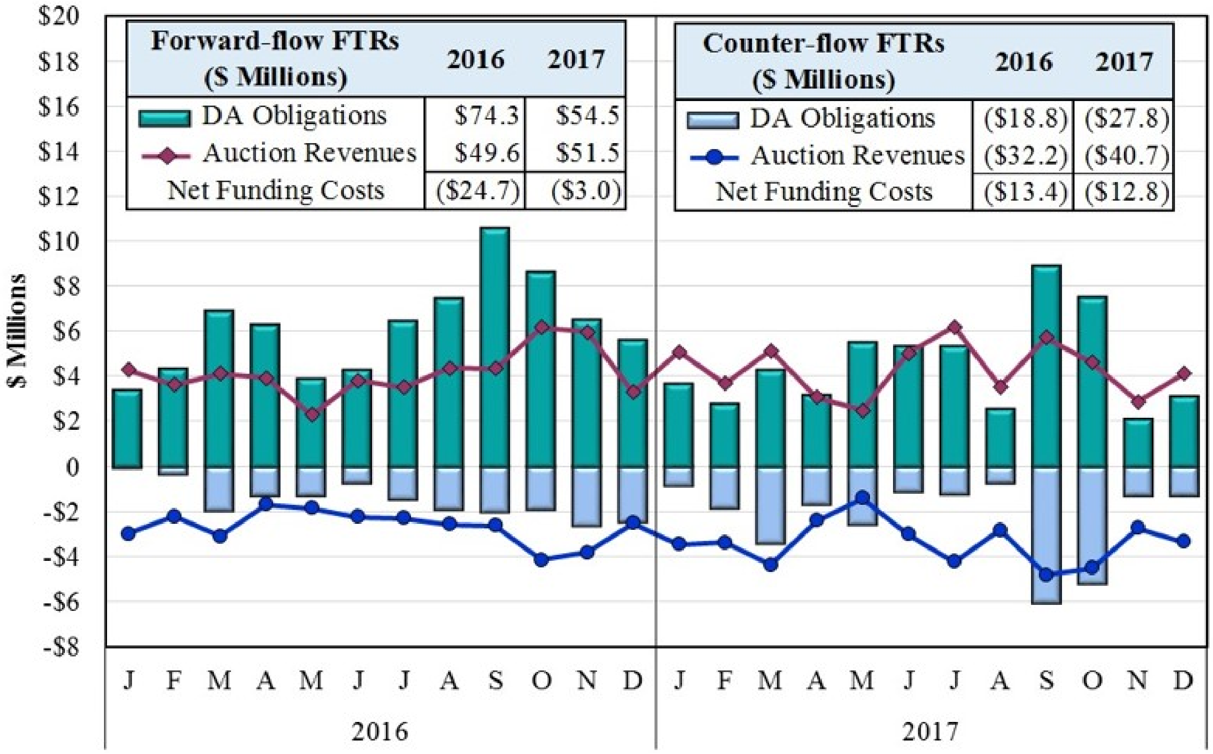
MISO is restricted in its ability to sell counter-flow FTRs because it is prohibited from clearing the MPMA with a negative financial residual. That means that MISO can only fund the purchase of counter-flow FTRs with net revenues from same auction. This artificial restriction limits MISO's ability to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

34 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 counter-flow FTRs at a price less negative than their ultimate value.

Figure 32: Prompt-Month MPMA FTR Profitability
2016–2017



This figure shows that MISO sold forward-flow FTRs at $3 million less than their ultimate value in 2017, a significant improvement over 2016. However, MISO paid participants 46 percent more to accept counter-flow FTRs than the value of these obligations 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 2017 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. 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

During 2017, MISO and the IMM continued to work with transmission operators on processes and procedures to enable greater utilization of the transmission network. This can be accomplished by operating to higher transmission limits, which would result from consistent use of improved ratings for MISO's transmission facilities, including:

- Temperature-adjusted transmission ratings;
- Emergency ratings; and
- Use of dynamic Voltage and Stability ratings.

As detailed in the Analytical Appendix, substantial savings could be achieved through widespread use of temperature-adjusted transmission ratings for all types of transmission constraints.[35] For contingency constraints, these temperature-adjusted ratings should correspond to the short-term emergency rating level (i.e., the flow level that the monitored facility could reliably accommodate in the short term if the contingency occurs). Most transmission owners provide MISO with both normal and emergency limits, but we have identified transmission owners that provide only normal ratings.

To estimate the congestion savings of using temperature-adjusted ratings, we used NERC/IEEE estimates of ambient temperature effects on transmission ratings and hourly local temperatures to calculate adjusted limits on real-time binding transmission constraints. The value of increasing the transmission limits was calculated by multiplying the increase in the temperature-adjusted limit by the real-time shadow price of the constraint. This analysis indicates that as much as $127 million in production costs savings could be achieved by fully adopting temperature-adjusted, short-term emergency ratings throughout MISO.

In 2015, MISO implemented a pilot program to employ temperature-adjusted, short-term emergency ratings on a number of key facilities, and this has matured into an ongoing program. The program has had clear benefits with no reliability issues. Expansion of the program will

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

likely generate considerable savings on constraints throughout MISO. We continue to recommend that MISO work with transmission owners to gather and use temperature-adjusted, short-term emergency ratings in the real-time market. Additional savings could be achieved by using predictive ratings in the day-ahead market that would be based on forecasted temperatures and wind speeds. In addition, MISO plans to evaluate the costs and benefits of using predictive ratings in the day-ahead market.

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 the monitoring and non-monitoring RTOs. The process allows each RTO to utilize re-dispatch from the other RTOs' resources 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 rights (Firm Flow Entitlements or "FFEs") on the "coordinated" constraint. The process requires RTOs to calculate the shadow price on the constraint based on their own production cost of unloading it. The RTO with the lower-cost re-dispatch responds by reducing 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 by paying it for the marginal value of the difference between the non-monitoring RTO's FFE and the market flow. Conversely, if the non-monitoring RTO's market flow exceeds its FFE, it will pay the monitoring RTO for the excess flow.

Summary of Market-to-Market Settlements

Congestion on MISO market-to-market constraints rose 24 percent from $377 million in 2016 to $467 million in 2017. Congestion results on market-to-market constraints included:

- Congestion on external market-to-market constraints (those monitored by PJM and SPP) fell 6.5 percent.
- Net payments flowed from PJM to MISO because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system.
  - Net payments from PJM totaled $53 million, an increase of 38 percent from 2016.
  - The increase was caused by resources pseudo-tying into PJM, the corresponding definition of new market-to-market constraints, and PJM's flawed interface pricing methodology that generally inflates congestion payments to imports and exports. However, these payments were likely suppressed as a result of PJM's lack of implementation of some market-to-market testing, which is discussed further below.
- MISO's market-to-market settlements with SPP in 2017 resulted in net payments of $23 million from MISO to SPP.

A portion of the increase in market-to-market congestion was associated with constraints that were not managed under conventional market-to-market coordination, including using overrides, safe operating modes, TLRs, or other processes to manage the congestion. Although sometimes justified, these alternatives are generally less efficient and lead to higher congestion costs. Hence, MISO should work with PJM and SPP to avoid these alternative means of coordinating.

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.

Convergence is much less reliable in the day-ahead market, but MISO and PJM implemented our recommendation to coordinate FFE levels in the day-ahead market in late January 2016. The RTOs have not actively utilized this process, so it has not had substantial effects. However, we will continue to evaluate the effectiveness of this process in improving day-ahead market outcomes. SPP has not agreed to implement a similar day-ahead coordination procedure.

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 174 non-market-to-market constraints that should have been coordinated as market-to-market with either PJM or SPP. Table 8 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 8: Congestion on Constraints Affected by Market-to-Market Issues
2017

Item Description	PJM ($ Millions)	SPP ($ Millions)	Total ($ Millions)
Never classified as M2M	$84.6	$109.2	$193.9
M2M Testing Delay	$19.3	$11.5	$30.8
M2M Activation Delay	$6.3	$12.1	$18.5
Total	$110.3	$132.9	$243.1

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 2017, MISO began to develop and use a tool to improve these procedures, but further improvement is needed because failure to coordinate the management of these constraints can generate sizable congestion costs. In the fall, for instance, MISO incurred almost $50 million in congestion on a single constraint that likely should have been classified as a market-to-market constraint with PJM.

Additionally, in response to MISO inquiries on testing results, PJM acknowledged in 2017 that they had not implemented one of the required market-to-market tests for coordination since the outset of JOA operations in 2005.[36] Based on the investigation performed by the RTOs, this issue accounted for a relatively small share of the congestion reported in the Table 8.

Finally, a key insight of our evaluation is that some of the most costly 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). For example, one market-to-market constraint alone accounted for $40 million of congestion early in 2017 and was difficult to manage because it was dominated by PJM. On February 7, MISO transferred the monitoring of this constraint to PJM, and congestion on the constraint was significantly reduced as a result. However, such transfers have been rare.

To facilitate this process, MISO and SPP began using new software in 2017 that enables the RTOs to transfer monitoring responsibility of flowgates, but it has only been used on a limited basis. 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.

36 In response to concerns expressed by MISO, PJM implemented Study 1 of the CMP 3.2.1 in December 2017.

F. Effects of Pseudo-Tying MISO Generators

Increasing quantities of MISO capacity have been exported to PJM. PJM has implemented rules that require external capacity to be pseudo-tied to PJM. We have been raising serious concerns about the increasing numbers of pseudo-tied resources because allowing PJM to take dispatch control of large numbers MISO generators will:

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

The following table and figure summarizes our evaluation of some of the effects of pseudo-tying the generators to PJM. The purpose of this analysis to determine whether the pseudo-ties are leading to less efficient congestion management and higher congestion costs as a result.

In Table 9, we quantified the number of new market-to-market constraints and the associated congestion in 2016 and 2017 caused by pseudo ties. In our analysis, we identified new market-to-market constraints that had not been market-to-market before and then passed the market-to-market tests because at least one pseudo-tied resource had a significant impact on the constraints. The associated congestion is the real-time congestion value that accrued on the new market-to-market constraints since the units were pseudo-tied to PJM.

Table 9: New Market-to-Market Constraints Caused by Pseudo-Ties to PJM

Year	M2M Constraints due to Pseudo-ties	RT Congestion on M2M Constraints ($ Millions)
2016	66	$70
2017	29	$85
Total	**95**	**$155**

This table shows that many new constraints have had to be defined as a result of PJM's policy of requiring capacity exporters from MISO to pseudo-tie their resources to PJM. These quantities would be even larger if MISO requested testing on all constraints that would potentially satisfy the market-to-market tests. The table also shows that these constraints generate a large amount of congestion, exceeding $150 million in 2017.

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. To estimate the size of this inefficiency, we compared the congestion on these constraints after the pseudo-ties were implemented to the congestion on the same constraints that occurred in the 15 months prior to the pseudo ties. We found:

- The real-time congestion values on the constraints affected by the pseudo-tied resources increased by more than 70 percent after the pseudo-ties were implemented.
- This increase occurred largely because pseudo-tied units located on MISO's transmission system are now under the dispatch control of PJM, which is undermining MISO's ability to efficiently manage congestion on the affected portions of the MISO network.
- *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.*[37]

We further evaluated our concerns with pseudo-tied resources by assessing how efficiently the current 12 PJM-pseudo-tied units were dispatched when they affected constraints on MISO's system. We did this by calculating the inefficient production costs that they incurred (relative to the MISO LMP at their location) divided by their total energy production costs in hours when congestion was greater than $5 per MWh at the units' locations. In 2017, our evaluation showed:

- Eight of the twelve units exhibited average inefficiencies greater than **24 percent** when online (i.e., running at much higher or lower levels than optimal in congested periods).
- Including periods when the pseudo-tied units were not committed by PJM even though they were clearly economic based on MISO's LMPs, the weighted-average inefficiency exceeded **35 percent** for all the pseudo-tied units.

Based on these results and our other assessments, 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.[38] FERC has yet to address this complaint.

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37 MISO also loses the ability to economically commit/decommit pseudo-tied units to manage congestion.

38 See Complaint filed in Docket No. EL17-62, April 5, 2017.

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 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 physically binding when they are severely binding in MISO. 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 2017

Types of Constraint	Total Congestion ($ Million)	Re-dispatch Savings ($ Million)
MISO Constraints	$75.1	$9.5
TVA (TLR) Constraints Binding in MISO	$7.1	$2.7
Total	$82.2	$12.2

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 on the Volunteer-Phipps Bend (VPB) line when MISO was in a Maximum Generation Emergency Event. This caused:

- MISO to activate the constraint in its real-time dispatch, which led to widespread redispatch changes; and
- Increased 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 lower 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. External Transactions

A. Overall Import and Export Patterns

As in prior years, MISO remained a substantial net importer of energy in both the day-ahead and real-time markets in 2017:

- Hourly net imports in the day-ahead and real-time markets averaged 5.4 and 6.3 GW, respectively.
- MISO's largest and most actively-scheduled interface is the PJM interface. MISO was a net importer from PJM in 2017.
  - Hourly average real-time imports from PJM were 1,969 MW.
  - Some of the scheduling patterns between MISO and PJM were inefficient because of flaws in the RTOs' interface prices, as discussed below.

Interface price differences create incentives for physical schedulers to import and export between MISO and adjacent areas. These interchange adjustments are essential from both economic and reliability standpoints. 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, arbitrage of interregional price differences is hindered by the fact that 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 leads to substantial errors in the aggregate quantities of transaction schedule changes.

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. More than half of the transactions with PJM were scheduled in the profitable direction, and 64 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 particularly notable savings.

To address these issues, MISO and PJM introduced CTS in October 2017, which allows market participants to submit offers to schedule imports or exports between the RTOs within the hour if the forecasted spread between the MISO and PJM real-time interface prices is greater than the offer price. This allows the RTOs to adjust transaction schedules every 15 minutes to achieve savings by better utilizing the interface.

Unfortunately, the volume of transactions cleared under CTS has been negligible because of the charges and fees imposed by MISO and PJM. For example, transmission reservation fees alone (charged to all CTS offers) result in average costs per cleared MWh ranging from roughly $22 per MWh on exports to almost $7 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.

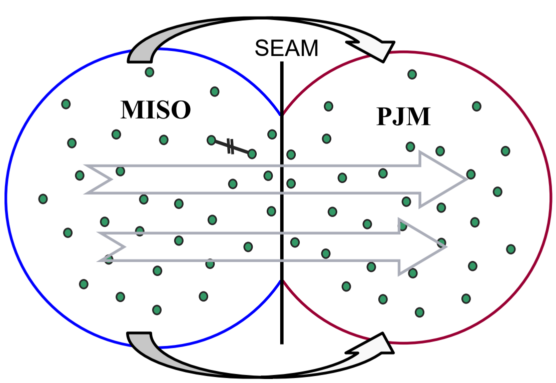
B. Interface Pricing and External Transactions

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 come into equilibrium (and generation costs are equalized). However, congestion is pervasive on these systems, so the fundamental issue with interface pricing is estimating the congestion costs and benefits from cross-border transfers (imports and exports).

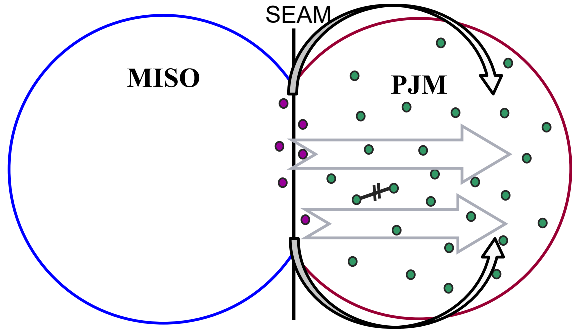
Like the locational marginal price at all generation and load locations, the interface price includes: a) the SMP, b) a marginal loss component, and c) a congestion component. For generator locations, the source of the power is known and, therefore, congestion effects can be accurately calculated. In 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 where the power is actually coming from (import) or going to (export), the interface price will provide an efficient incentive to transact and traders' responses to these prices will lower the total costs for both systems.



In reality, when power moves from one area to the other, generators ramp up throughout one area and ramp down throughout the other area (marginal units), as shown in the figure to the left. This figure is consistent with MISO's interface pricing before June 2017, which calculated flows for exports to PJM based on the power sinking throughout PJM. This is accurate because PJM will ramp down all of its marginal generators when it imports power.

Interface Pricing with PJM

However, PJM's assumptions are much different. It assumes the power sources and sinks from the border with MISO, as shown in the figure to the right. This approach tends to exaggerate the flow effects of imports and exports on any constraint 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 on all of its interfaces tend to 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 (2 GW on average). For example, we previously showed that in 2015:

- On average, MISO's system marginal price was 29 percent ($7.56/MWh) lower than PJM's, suggesting that MISO should be exporting power to PJM.
- However, PJM's average congestion component at the interface was -$4.10 per MWh, which substantially changed the incentive of participants to schedule imports and exports.
- This suggested that, on average for 2015, every MW exported from PJM to MISO would produce more than $4 per MWh of congestion savings.
- 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. In 2015, we estimated that PJM's congestion settlements at the MISO interface resulted in overpayments to transactions of almost $45 million.

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 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.

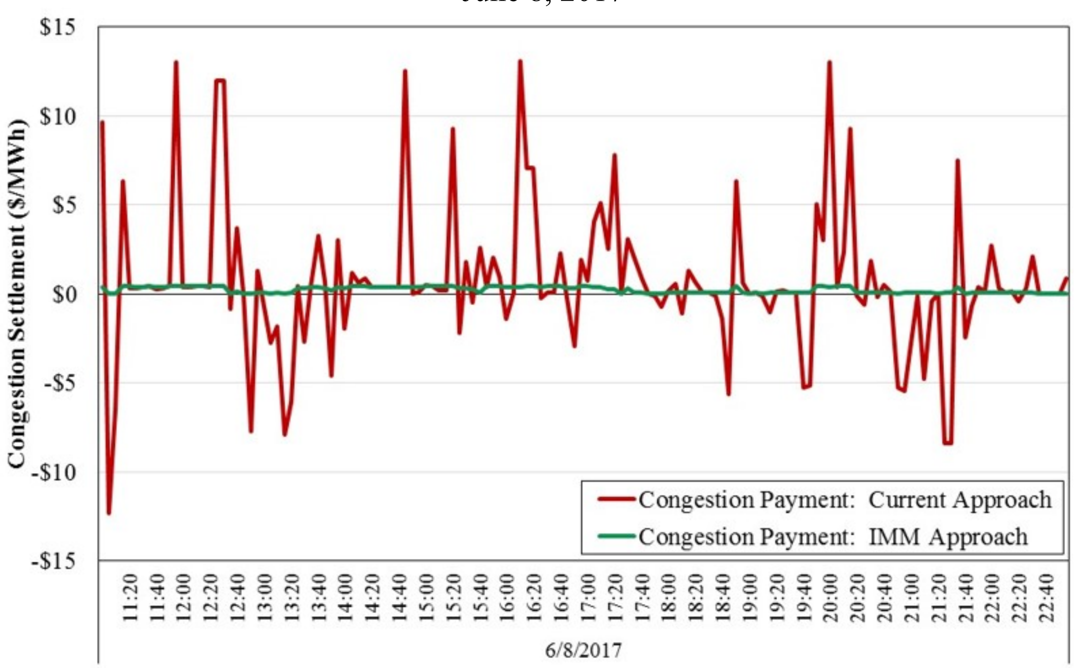
However, the Common Interface has introduced new inefficiencies that more than offset the benefits of improved real-time pricing of the market-to-market constraints:

- 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. Section VII.B of the Analytic Appendix shows a figure that summarizes our analysis of the interface pricing alternatives, as well as examples in the day-ahead and real-time markets that show how poorly the common interface sometimes performs.

Figure 33 shows one such example from the real-time market.[39] In this figure, the red line represents the congestion incentive associated with MISO's constraints to schedule transactions between PJM and MISO under the current common interface definition. The green line represents the congestion incentive to schedule transactions under the approach we have recommended. Our approach would have MISO calculate the congestion component for all MISO constraints based on MISO's legacy interface definition that assumed imports from PJM sourced from all non-nuclear generators in the PJM footprint. Although this is not ideal, it is the best pricing that MISO can implement assuming that PJM retains its current common interface.

Figure 33: Example of Congestion Pricing under the PJM-MISO Common Interface
June 8, 2017



39 Analytic Appendix Section VII.B includes other examples from both the day-ahead and real-time markets.

The case study demonstrates that the current incentives to schedule transactions between PJM to MISO is not aligned with the effects of the transactions on MISO's constraints. In addition to the volatility, this pricing often provides incentives to schedule in the wrong direction – paying participants to schedule transactions that will exacerbate the congestion. These poor results are caused by differences between the shadow prices in the PJM and in the MISO markets for the market-to-market constraints, and the pricing errors on non-market-to-market constraints caused by the unrealistic common interface. Based on these results and our other evaluations of the current common interface, we conclude that it was a mistake for MISO to agree to this approach and would be beneficial for MISO to adopt the IMM-proposed interface pricing approach.

Interface Pricing for Other External Constraints

PJM market-to-market constraints are only one type of external constraint that MISO includes in its real-time market. 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. Although we have concerns that are described earlier in this section regarding the cost of external constraints, it is nonetheless appropriate for external constraints to be reflected in MISO's real-time dispatch and internal LMPs – this enables MISO to respond to TLR relief requests as efficiently as possible. While re-dispatching internal generation is required, 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 duplicative and inefficient.
- MISO's shadow cost for external TLR constraints is generally overstated by multiples relative to the true marginal cost of managing the congestion on the constraint. This causes the interface price to provide inefficient scheduling incentives.

One should expect that this will result in inefficient schedules and higher costs for MISO customers. Therefore, we continue to recommend that MISO take the necessary steps to remove all other external congestion from its interface prices, regardless of its decision related to the interface.

VIII. Competitive Assessment and Market Power Mitigation

This section contains our competitive assessment of the MISO markets, including a review of market power indicators, an evaluation of participant conduct, and a summary of the use of market power mitigation measures in 2017. 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 (574) but relatively high in some local areas, such as the WUMS Area (2708) and the South Region (3664). 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:

- Ninety-two 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 97 percent of the active constraints.

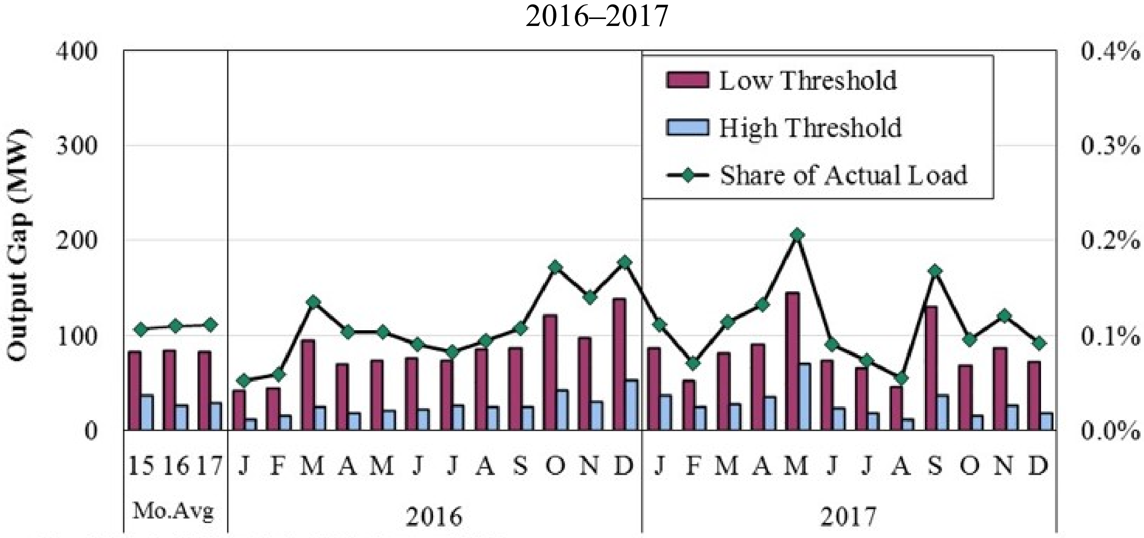
Overall, these results indicate that local market power persists, with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

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 *-0.1* percent in 2017, varying monthly from a high of *1.5* percent to a low of *-2.1* 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 34: Economic Withholding – Output Gap Analysis
2016–2017



Low Threshold Results by Unit Status (MW)

Offline	27	12	6	6	13	0	1	0	1	15	12	13	30	21	25	14	6	8	11	14	4	2	2	16	0	0	0
Online	55	71	76	36	32	94	69	73	74	58	72	73	89	75	113	72	46	73	79	130	69	63	44	114	68	86	72

High Threshold Results by Unit Status (MW)

Offline	23	10	6	5	11	0	1	0	1	15	10	11	26	21	24	14	6	8	11	14	4	2	1	12	0	0	0
Online	14	15	22	6	5	25	16	20	20	11	14	14	16	8	29	23	19	19	24	55	20	16	10	24	15	26	19

The figure shows that the average monthly output gap level was 0.1 percent of load in 2017, 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 2017 were appropriate and effectively limited the exercise of market power. The imposition of mitigation in the energy market remained infrequent in 2017, but RSG mitigation increased, as described below.

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 2017. 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. However, irrational regulation offers by one supplier were mitigated relatively frequently.

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 2017, total RSG mitigation rose by $2 million as mitigation of RSG paid to resources committed for VLR needs increased substantially. 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. However, mitigation of RSG payments incurred to manage congestion remained low in 2017.

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. As of the date of publication, no Dynamic NCAs have yet been activated.

IX. 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 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 11 shows overall DR participation in MISO, NYISO, and ISO-NE in the prior three years.

Table 11: Demand Response Capability in MISO and Neighboring RTOs
2015–2017

		2015	2016	2017
MISO[1]		**10,563**	**10,721**	**11,682**
	Load Modifying Resource - BTMG	4,213	4,089	4,009
	Load Modifying Resource - DR	5,121	4,616	6,112
	DRR Type I	330	525	620
	DRR Type II	116	75	0
	Emergency DR (non-LMR)[2]	782	1,416	941
NYISO[3]		**1,326**	**1,267**	**1,237**
	ICAP - Special Case Resources	1,251	1,192	1,221
	Of which: Targeted DR	385	372	392
	Emergency DR	75	75	16
	Of which: Targeted DR	14	14	1
	DADRP	0	0	0
ISO-NE[4]		**2,685**	**2,600**	**2,657**
	Real-Time DR Resources	692	702	683
	Real-Time Emerg. Generation Resources	300	2	2
	On-Peak Demand Resources	1,222	1,386	1,418
	Seasonal Peak Demand Resources	471	510	554

[1] Registered as of December 2017. All units are MW.

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

[3] Registered as of July 2017. Retrieved May 2, 2017. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.

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

The table shows that MISO had more than 11.5 GW of demand-response capability available in 2017, which is a larger share than the capability in neighboring RTOs. MISO's capability exhibits varying degrees of responsiveness. Nearly 90 percent of the MISO DR is in the form of LMRs that are interruptible load developed under regulated utility programs and BTMGs.

Although 23 DRRs were active in the MISO markets in 2017, they only cleared a small amount of energy and reserves in the MISO markets. All of these units were DRR Type 1 (non-dispatchable DRRs). As 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 upon in MISO since 2007. They have, however, become increasingly important in both planning and operations during emergency events. LMRs were deployed once in April 2017 and twice in January 2018 in MISO South. We discuss the events in detail in Section II.D of this Report.

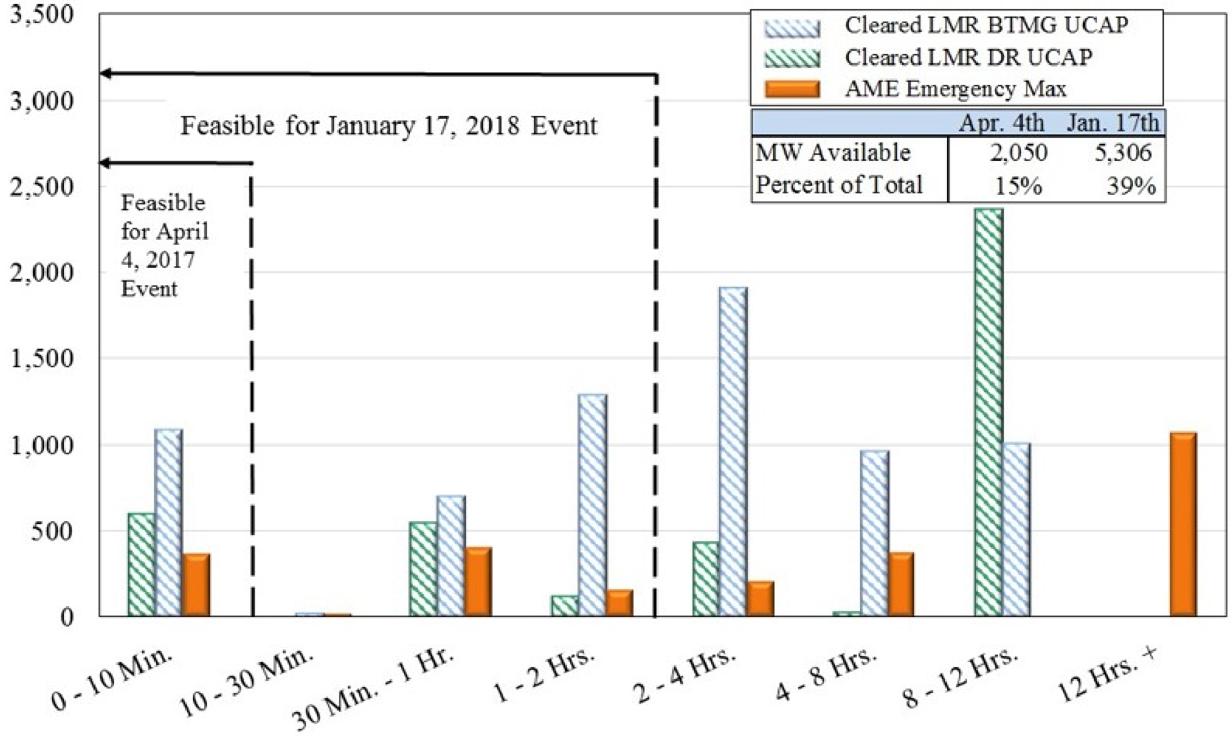
LMRs are either DR or BTMGs that clear in MISO's annual capacity auction. They are obligated to curtail load up to five times during the summer months, subject to a notification time of 12 hours or less. MISO can schedule LMRs only when it declares a Maximum Generation Event level 2b or higher – making LMRs accessible only after all other resources have been utilized in emergencies. This severely limits the accessibility of LMR resources because emergency events are generally not foreseen in advance since they tend to be caused by multiple concurrent contingencies and/or higher than expected load. We evaluate the availability of these resources during the past two emergency events in which LMRs were called (April 4, 2017 and January 17, 2018). Figure 35 below shows this evaluation, subdividing the LMRs and other emergency resources by notification time.

The figure indicates the share of these resources that would have been available during these two emergencies at the time when the emergencies were called. For AME resources, we included the average capacity offered with the various notification times during the peak hour on the two days in question. The solid areas are the resources that are available year-round, while the hashed areas are resources that are only obligated to be available in the summer. Figure 35 below shows the following results for the two events:

- April 4, 2017: Only three percent of all emergency resources would have been available during the event (excluding those only obligated to offer in the summer) because the event was called only ten minutes in advance of the emergency. If the units only obligated to be available during the summer were included, 15 percent of the emergency resources would have been available during this event.

- January 17, 2018: MISO declared this emergency two hours before the critical period of the event. Only seven percent of all the year-round 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.

Figure 35: Availability of Emergency Resources
On April 4, 2017 and January 17, 2018



	Apr. 4th	Jan. 17th
MW Available	2,050	5,306
Percent of Total	15%	39%

Using these two cases as examples, the analysis shows that most 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, emergency resources 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 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:

- Transitioning to a seasonal capacity auction; and
- Providing capacity credits under Module E that reflect emergency resources' availability, recognizing both their historic performance and their startup notification times.

X. Recommendations

Although MISO's markets continued to perform competitively and efficiently in 2017 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: 9 total, 1 new.
- Operating Reserves and Guarantee Payments: 4 total, 1 new.
- Dispatch Efficiency and Real-Time Market Operations: 8 total, 3 new.
- Resource Adequacy: 8 total, 2 new.

Twenty-two 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 four of our past recommendations in 2017 or early 2018. We discuss recommendations that are addressed at the end of this section. Included in this section are also five recommendations 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.

2017-1: Improve the market power mitigation rules

Over the past few years, we have 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 sanctions 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: This is a new recommendation.

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 RTO's 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 other charges when they are scheduled that are substantial. Given that a small portion of the offered transactions are scheduled, the reservation charges along translate to almost $7 per MWh on scheduled imports and more than $22 per MWh on scheduled exports and make it virtually eliminate the incentive to submit CTS bids and offers. This is consistent with reality – CTS offers were small initially in November, but have fallen consistently and have been zero since mid-February 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: This is a new recommendation.

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 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 26 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 implemented the Phase II changes on May 1, 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). These changes have resulted in only modest improvements and we find that additional changes must be made to allow the ELMP model to set efficient prices. MISO has completed an initial evaluation of ELMP Phase II and is evaluating the improvements recommended above. MISO does not agree with the offline pricing recommendation and does not plan on taking any action to address it.

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 of reduced congestion costs of $155 million in 2016 and $127 million in 2017 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 substantial potential savings in congestion costs could be 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: The pilot program with one transmission operator has been highly successful at reducing congestion costs and RSG costs, although it has been applied to a very small number of constraints. In addition, a small number of transmission owners have begun to make use of MISO's interface for submission of Dynamic Ratings.

However, MISO has not developed a comprehensive program to identify opportunities to improve ratings across its system or a day-ahead program to use predictive ratings. MISO has aligned this recommendation with a Roadmap project called "Application of Dynamic and Predictive Ratings." However, this project proposed by MISO stakeholders is classified as a low priority and MISO has provided no update since February 2017.

Next Steps: MISO should continue working with other transmission operators to expand its program to other areas. To facilitate this expansion, we continue to recommend that MISO develop procedures to utilize predictive temperature-dependent ratings in its day-ahead market.

2012-5: Introduce a virtual spread product

Nearly 70 percent of price-insensitive virtual bid and offer volumes (and five percent of all volumes) in 2017 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 continues to discuss this recommendation with stakeholders and has held a number of workshops with stakeholders to explore the development of such a product. MISO continues to evaluate costs and benefits and develop software improvements (including the MSE program) that will mitigate the impact of a virtual spread product on the day-ahead solution times. Currently this recommendation is included in MISO's Roadmap as a Parking Lot item and a low priority and no update has been provided since February 2017. MISO had previously committed to evaluate this recommendation, but this evaluation is not currently planned.

Next Steps: MISO should complete an evaluation of the benefits and costs of a spread product. This will allow MISO and its stakeholders to determine the priority for this product.

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

As noted last year, 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. MISO and TVA have recently initiated 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.

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 relief and where local actions (redispatch and reconfiguration) are 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).

2016-1: Improve shortage pricing by adopting an improved contingency reserve demand curve that reflects 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 the current curve, so it should not substantially increase consumer costs for these shortages. 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.

<u>Status:</u> In response to FERC Order 831 to raise the offer cap, MISO filed to increase the contingency reserve demand curve. MISO has acknowledged that it intends to study and pursue an improved ORDC, although this item is in the Parking Lot in the Market Roadmap process (Report Card 60).

<u>Next Steps</u>: We have performed a detailed analysis to support a more efficient ORDC. The next step is for MISO to work with the IMM and its stakeholders to improve the ORDC.

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 and involve considerable levels of discretion and interaction between multiple business areas within and across RTOs. In 2017, we continued to identify significant congestion on constraints that were not established as M2M constraints even though they appeared to qualify under the M2M tests.

We also continued to identify some delays in establishing new M2M constraints or activating existing M2M constraints that reduce the effectiveness of M2M coordination in 2017.

Our analysis indicates in 2017, that $243 million of congestion costs could have been more effectively managed if M2M coordination testing and activation procedures were more complete and timely. 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 continue to recommend that MISO improve the automation of its procedures for:

- Identifying and making timely requests for M2M testing of new constraints;
- Logging of the M2M testing requests and validating testing results;
- Promptly activating M2M constraints; and
- Transferring of monitoring of M2M constraints when it would be beneficial to do so.

Status: Although much more needs to be done, MISO has taken some actions to address some of these issues in 2017 and early 2018:

- MISO developed a tool to identify constraints that should be tested for M2M coordination. This tool is in use daily on a trial basis and has proven useful in detecting constraints that should be tested and coordinated under the JOA.
- MISO and SPP began using the software to permit each RTO to effectively transfer control of M2M flowgates to the NMRTO. PJM has not yet agreed to use this software.

Next Steps: First, MISO should complete the testing and deployment of an automated tool to identify constraints that should be submitted for M2M testing. The tool should be executed in real time (ideally hourly), and MISO should develop corresponding procedures to minimize the delays in testing and activating M2M constraints.

Second, MISO should develop procedures to ensure the new software that enables transfer of monitoring flowgates with SPP is applied without unwarranted delays. As soon as practicable, MISO should work to gain PJM's agreement to extend the use of this software to PJM.

Lastly, we recommend that MISO, PJM, and SPP (and all CMPWG members) establish a regular process to review and audit JOA and CMP operations to ensure compliance with the JOA tariff requirements, including validation of calculations currently performed within the IDC and implemented by OATI. These parties already have a regular process to review coordination issues and to share information, but the mandate and responsibility of this group does not include an audit/compliance review.

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 2017, multiple simultaneous generation outages contributed to $400 million in real-time congestion costs – more than 30 percent of all real-time congestion costs.

Most of the other RTOs in the Eastern Interconnect have 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."[40] The ISO New England program has been found to have been very effective at avoiding unnecessary congestion costs.[41]

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.

Status: MISO has begun to consider improvements as part of its Resource Availability and Need (RAN) initiative.

Next Steps: Continue to consider options under the RAN initiative, including acquiring more tariff authority to review and coordinate outages.

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, either through the TLR process or 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.

40 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.

41 JUNE 25, 2012 FERC Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency, Presentation by ISO-NE.

Status: This recommendation was originally made in our *2012 State of the Market Report.* Over the past five 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.

However, MISO 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.

Next Steps: Develop the workplan necessary to modify its interface prices. We believe MISO has made the software changes necessary to implement this recommendation.

D. Operating Reserves and Guarantee Payments

Many of MISO's reliability needs are addressed through its operating reserve requirements that result in resources being 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.

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 imperative that MISO have a robust process for reviewing and correcting commitment classifications as needed. In addition, recognizing that commitments may often address multiple issues and constraints simultaneously, MISO needs clear procedures for determining the classification that is driven by cost-causation principles.

Status: This is a new recommendation.

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

MISO is incurring substantial RSG costs in a limited number of areas to satisfy VLR requirements. These costs arise as MISO commits additional local resources to prepare the area to withstand both the largest potential contingency in the area as well as the second largest contingency. These requirements are attributable to the fact that some areas do not have resources that can start within 30 minutes to restore the lost reserves after the first contingency. In essence, MISO is committing resources to hold reserves on online resources.

We recommend that MISO create a local 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 needs at a much lower cost (because they can satisfy the requirements while offline).

Additionally, to the extent that MISO operators perceive reliability needs more broadly that can be satisfied by a 30-minute reserve product, MISO should consider establishing market-wide requirements for 30-minute reserves. A number of other RTOs have 30-minute reserve products and they are valuable for pricing services that can be provided by peaking resources that cannot start in 10 minutes, which includes most of the peaking resources in MISO. Establishing market-wide requirements for 30-minute reserves would allow for an efficient expansion of MISO shortage pricing to include conditions when it is short of 30-minute reserves.

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 (Report Card ID 10) Requirements,* which is intended to address a similar 30-minute reserve requirement more broadly beyond the VLR areas. This project is currently planned for implementation in January 2020.

Next Steps: Given the benefits of this recommendation, MISO should increase the priority of this recommendation and accelerate its implementation, along with implementing a 30-minute reserve product beyond the VLR areas.

2016-4: Establish regional reserve requirements and cost allocation

In 2017, we continued to identify a substantial number of resource commitments and associated RSG payments made in MISO Midwest and MISO South to satisfy regional capacity needs when the Regional Directional Transfer constraint was binding or potentially binding. These commitments are not generally needed to manage the dispatch flows over the RDT constraint, but they ensure that sufficient capacity is available to prevent the flows from exceeding the RDT limit for more than 30 minutes after the largest contingency occurs in the importing region. These commitments are made outside of the market because MISO's markets do not include regional capacity requirements.

The 30-minute reserve product recommended in 2014-2 could be expanded to reflect these regional capacity needs. This would likely alter the resource commitments in the day-ahead market to satisfy these needs at overall lower costs. It will also price these requirements, including allowing the markets to price shortages when the regional resources are insufficient to satisfy the full reserve requirement.

Status: MISO has aligned this with the Roadmap Item *Short Term Capacity Pricing and Reliability (Report Card ID 10).* In 2017, MISO proposed the use of the RPE in the commitment software (both in the day-ahead RSC and Forward RAC) to model the RDT requirements. Specifically, under this proposal the MISO South region would be modeled as zone and the RPE would be used to hold 10-minute reserves in MISO South or on the transfer constraint into MISO South.

Next Steps: We support MISO moving as expeditiously as possible to implement these products. While we support MISO use of the RPE as an improvement to non-market mechanisms, it is not a replacement for implementing a resource product that reflects the regional reserve requirement. Therefore, we continue to recommend MISO develop 30-minute reserve requirements for MISO South and MISO Midwest.

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. We have referred instances of such conduct to the Commission's Office of Enforcement.

The only means to address these concerns under the current rules are through eligibility criteria that cause a supplier to become ineligible for uplift payments if it exceeds MISO's Excessive and Deficient energy thresholds. Even with the improvements in these thresholds that we have recommended, these eligibility rules will not effectively address the performance and manipulation concerns. Therefore, we recommend 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: MISO has aligned this recommendation with the Roadmap Item "Reform DAMAP and RTORSGP Rules (Report Card ID 58) and has indicated support for this recommendation. MISO has been working with its participants and the IMM on reforms to the uninstructed deviation threshold. A proposal has been developed that would address this recommendation along with the improvements to the uninstructed deviation reforms. MISO plans to file this proposal in late 2018.

Next Steps: We believe this should be a high priority project and strongly support MISO addressing this as a component of the uninstructed deviation threshold changes.

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 and 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. It is these ramp demands that 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 six recommendations seek to improve on these processes.

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 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 M2M constraint tests and activations.
- Manual redispatch of resources that are made to satisfy system needs.
- Changes in operating status of generating units, including the change to place 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 System Enhancement could include enhancements to the logging tools to enable the improved logging.

Status: This is a new recommendation.

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 System 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 may now be feasible and cost-effective.

Status: This is a new recommendation.

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 effectively increases as the dispatch instruction increases.[42] 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 recommend MISO adopt thresholds based on resources' ramp rates that effectively differentiate poor performance from acceptable performance. Resources that are deemed to be deviating under this criteria should incur uninstructed deviation penalties and costs and lose eligibility to supply ancillary services and the ramp product, and 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

42 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.

remove the ramp and headroom on such units from the LAC in order to allow the LAC model to make better recommendations.

Status: MISO generally agrees with this recommendation and originally planned to implement this improvement in 2016. It has been delayed, and we will continue to work with MISO to perform any evaluations necessary to support its filing and implementation. This recommendation is currently aligned with the Market Roadmap (Report Card ID 30) and is noted as under construction and to be implemented in July 2018. MISO presented an analysis of this recommendation to stakeholders in the Fall of 2017 and most recently in the February 2018 Markets Subcommittee Meeting. This included an evaluation of a mileage-based alternative to the original recommendation. We support this alternative.

Next Steps: MISO and the IMM are working to finalize the proposal, simulate its impacts, and proceed to a filing at FERC.

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 2015 and 2016 indicates that the commitment recommendations are not accurate – 80 percent of the LAC-recommended resource commitments are ultimately uneconomic to commit at real-time prices. We also found that operators only adhere to 32 percent of the LAC recommendations, 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. Further work is needed and MISO is evaluating the IMM findings.

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 its procedures to increase adherence to the LAC recommendations.

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. Hence, the Excessive Energy settlement for wind resources is far more punitive than the Deficient Energy settlement rules. Hence, we recommend 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: MISO has aligned this recommendation with the Roadmap Item "Dispatchable Intermittent Resource (DIR) Modification (Report Card ID 40). This item is currently in the Roadmap Parking Lot with a low priority. However, MISO is proposing a change as part of its proposal to improve uninstructed deviation theresholds that would substantially reduce the excess energy penalty on the wind resources.

Next Steps: Work with the IMM and stakeholders to develop proposed changes to the Excess Energy threshold and settlement rules that can be evaluated, discussed, and ultimately implemented.

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' forecast 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 makes the MISO energy dispatch subject to chronic shortfalls related to the overforecasting. Additionally, overforecasting 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: MISO has begun to evaluate this recommendation and it is aligned with the Roadmap Item "Dispatchable Intermittent Resource (DIR) Modification" (Report Card ID 40). This item is currently in the Roadmap Parking Lot with a low priority, although work has begun.

Next Steps: Develop appropriate procedures to validate market participants' wind forecasts and a methodology to establish substitute forecasts when the participants' forecasts are inaccurate.

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 resources cannot be called by MISO before MISO has invoked nearly all other emergency actions, some of which are very costly and adversely impact the market. Further, most of MISO's demand response resources have very long notification times (e.g., 12 hours) so if they are not called until after the other emergency actions are fully utilized, MISO will receive very little effective relief. Hence, we reiterate this recommendation to modify the emergency procedures to allow MISO to utilize these resources in a more efficient manner.

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.

Next Steps: MISO should perform its evaluation and develop a plan for addressing this recommendation.

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.

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 is five 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 LOLE 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.

Status: This is a new recommendation, although we raised this issue in the Spring of 2017 prior to the 2017/2018 PRA.

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

Generating resources are qualified to sell capacity based on their forced outage performance, which is considered in the calculation of their Unforced Capacity (UCAP) levels. They are also 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. Additionally, intermittent resources that typically cannot produce energy at their maximum capability are qualified to sell capacity based on an expected available energy level. For example, wind resources typically are able to sell capacity in the PRA in an amount that is roughly 15 percent of their rated level.

Emergency-only resources can sell capacity are only required to deploy during emergencies when instructed by MISO. These resources include Load-Modifying Resources (including Behind the Meter Generation and Demand Response) and emergency-only generation. These resources are compensated in the PRA so that they can provide MISO additional resources to manage emergency conditions. However, 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 one to 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 two emergencies that caused MISO to schedule LMR resources. This is not a problem for conventional resources with long notification or start times.

Therefore, we recommend that LMRs and emergency-only resources receive full PRA capacity credit if they are expected to be reasonably available in an emergency. This means their time to deployment (notification plus start-up time/shut-down time) should be less than a benchmark to be determined by MISO (e.g., one or two hours). Establishing such a benchmark should be based on MISO historical experience regarding how long in advance of its capacity shortages MISO has typically declared a Maximum Generation Event to enable access to the emergency resources.

As a secondary associated issue, we also 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 the resource, including the resources' seasonal availability, variation in available curtailment quantity, and historical performance.

The objective of these changes should be to qualify the LMRs 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.

Status: This is a new recommendation.

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

The use of only a minimum requirement and 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 will sustain an adequate resource base. Instead, the region will have to rely exclusively 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 them for the competitive loads and suppliers.

Status: MISO has developed principles governing future market developments, including changes in its resource adequacy provisions and processes. The principles include the objective of facilitating efficient investment, which is consistent with this recommendation. However, there is currently no consensus among the participants and States on how to meet this objective. 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 economic objectives of the resource adequacy construct. The IMM will support this process by continuing to show 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.

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 outages that occurred after performing their Generation Verification Test Capacity (GVTC) test often qualify as planning resources even though they cannot be restored to service prior the end of the system peak season. In some cases, the asset owners have not decided to repair the resource and prefer to not offer the resource into the PRA. Not only do the current rules allow such resources to be offered, but the supplier would be potentially subject to physical withholding mitigation measures under the current Tariff if they do not offer.

If such units were required to enter a suspension status and ultimately to be retired, their interconnection service would be terminated, which potentially benefits others that 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> Recent Tariff changes enable a resource that is forced out of service to submit an Attachment Y Notice to MISO with just thirty (30) days' notice prior to changing to Retire or Suspend status (rather than the 26 weeks that is required for units that are not in Forced Outage). Since retired units and suspended units under certain circumstances are not qualified to participate in the PRA, these changes provide an avenue for participants to opt out of participating in the PRA (although it does not prevent them from participating).

<u>Next Steps</u>: Work with stakeholders to develop provisions that will: a) limit inoperable units from holding interconnection service indefinitely, and b) prevent resources with no reasonable expectation of being available during system peak conditions from qualifying as planning resources.

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.

Status: This issue was recently reintroduced into the stakeholder process where MISO proposed a two-season proposal. Use of two seasons does not capture the opportunity to achieve 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 Resource Availability and Need (RAN) Initiative (MISO Roadmap ID 25).

Next Steps: To capture the benefits described above, we recommend that MISO evaluate the costs and benefits of implementing four seasonal requirements rather than two seasons.

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.

Next Steps: MISO should continue to discuss this recommendation with stakeholders with the goal of adopting 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.

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 will begin selling capacity to PJM and may also pseudo-tie 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.

Status: 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.

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.

Next Steps: The next steps on this recommendation will likely depend on FERC's Order on our Section 206 complaint.

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. Additionally, MISO assumes power flows associated with importing capacity from external resources that is not consistent with where the resources are located, and also not consistent with how such imports will affect the scheduled flows over the RDT. Ultimately, these issues lead to sub-optimal capacity procurements and locational prices.

Hence, we recommend that MISO add the RDT and 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. This should include defining external capacity zones consistent with the interfaces MISO uses to operate the system in its day-ahead and real-time market. Likewise, MISO should model the RDT constraint consistent with how it is modeled in the day-ahead and real-time markets, which is determined by the settlement agreement between MISO, SPP, and its other neighbors. For both the RDT and other relevant internal constraints, MISO should establish shift factors that define how each internal and external zone affects each constraint. Ultimately, this is a very simple version of a constrained optimal dispatch (much simpler than MISO's energy market). It would allow MISO to represent all regional constraints that may be affected by multiple local zones (e.g., the way the three zones in MISO South affect the south-to-north transfer constraint) and activate any constraints that may arise in its simultaneous feasibility assessment.

Status: MISO recently reintroduced a proposal to partially address this recommendation by changing how it defines and sets prices for external zones. This recommendation is not aligned with the MISO Roadmap and MISO indicates it is inactive.

Next Steps: MISO will likely need to evaluate the software and other implications of implementing an efficient locational framework in the PRA. If it begins by modeling only the RDT constraint, it should endeavor to do so in a manner that will facilitate modeling additional constraints in the future.

G. Prior Recommendations Not Included in the 2017 Report

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 2017 and early 2018. These recommendations are discussed below, along with unresolved recommendations that are not included in this year's report.

Recommendations Addressed by MISO

2013-4: Improve alignment of the Planning Reserve Auction and the Attachment Y process governing retirement and suspensions.

Ideally, participants should be able to utilize the PRA to make decisions whether to retire or suspend units, or to return a unit to service from suspension. This allows them to make efficient retirement or suspension decisions. For example, a supplier may submit an offer into the PRA at a price that would cover its going forward cost or the cost that would justify returning from suspension. If such an offer clears, the unit is economic to be in service during the planning year.

Suppliers that have submitted an Attachment Y retirement request currently lose their interconnection rights as of the specified retirement date once the Attachment Y Reliability Study results are received, unless the unit was designated as an SSR Unit. For SSR Units, the interconnection rights are retained until the termination of the SSR agreement. These rules should be modified to allow the broadest possible participation in the PRA, and to allow participants' ultimate decisions to be efficiently facilitated by the PRA. Flexibility will improve market efficiency by reducing inefficient barriers to participating in the PRA.

Status and Resolution: MISO did modify the use of the provisions in its Tariff, making the provisions available to suspended resources. It was previously available only to new resources and those that were untested because of a catastrophic outage. This change became effective on December 6, 2014. MISO filed Tariff language that allows suspended resources to offer into the PRA. FERC conditionally accepted the revisions on February 12, 2016.

MISO also modified the Attachment Y Notice provisions in its Tariff that apply to resources changing to retirement or suspension status from being in a forced outage. However, the Tariff does not require them to make the change from forced outage to retirement or suspension.

MISO has filed Tariff changes that eliminate most of the distinction between suspensions and retirements, which increases the flexibility of units with pending retirements to participate in the PRA. The filed Tariff changes enables SSR units to retain their interconnection rights and continue to operate in the event that the SSR contract is terminated prior to the end of the planning year. This removes a significant barrier to participation in the PRA. FERC acceptance of the language as filed fully addresses our recommendation to improve the alignment of the PRA and the Attachment Y process.

2015-4: Enhanced tools and procedures to respond to poor dispatch performance.

In our 2012 report, we recommended changes to the tools used by MISO's operators. These changes were intended to facilitate RGDs in the identification of poor generator performance. In response to this recommendation, MISO implemented a new tool that calculates and utilizes a simplified version of the metric we had recommended. Based on our continued monitoring of these issues, we conclude that MISO's real-time tools and processes have not been effective in addressing the issues related to poor generator performance, which include: 1) resources responding poorly to set-points (dragging), and 2) resources not responding to set points that are effectively off-control or derated (an "inferred derate").

Status and Resolution: In 2017, based on additional analysis, MISO agreed its internal tools and procedures were not adequately identifying units that were performing poorly. In the long-term MISO plans to modify its internal tools. In the interim, MISO will modify its procedures to use alerts produced and provided by the IMM. Under these procedures MISO will respond to alerts by contacting the relevant generator. Based on the response, MISO will consider a number of actions consistent with the Normal Operating Procedure SO-P-NOP-02 (formerly OP-10). Finally, MISO will be logging the response and outcome of its actions.

In addition, we had recommended that MISO develop new tools to identify and address cases when State-Estimator residuals (differences between estimated resource output and measured output) are impacting economic dispatch. In 2017, MISO worked with the IMM to improve the process of identifying and resolving State-Estimator residuals. MISO also implemented changes to the UDS inputs and timing that also helped reduce dragging caused by the latency of State-Estimator inputs.

2012-2: Implement a five-minute real-time settlement for generation.

MISO clears the real-time market in five-minute intervals and sends corresponding dispatch instructions to generators on a five-minute basis. However, it settles generation on an hourly basis. This can create inconsistencies between the dispatch signal and the hourly prices that can create incentives for generators to not follow the dispatch signal or to simply be inflexible. This inconsistency is only partially addressed by the PVMWPs. Implementing this recommendation will improve the incentives for generators to follow dispatch instructions and provide more flexibility.

Status: This recommendation was originally proposed in our 2012 State of the Market Report. FERC issued Order 825 on June 16, 2016 that required each RTO/ISO to align settlement and dispatch intervals in the real-time markets. In January 2017, MISO made a compliance filing that proposes to settle generation and operating reserves on 5-minute intervals. Interchange transactions would continue to settle at 15-minute intervals and load would continue to settle hourly. FERC approved MISO's filing in May 2017. MISO projects completion of its settlement system upgrade in the third quarter of 2018, to be followed by the planned implementation of this recommendation in the first quarter of 2018.

2012-9: Allow the definition of a "Dynamic NCA" that is utilized when network conditions create substantial market power.

The Tariff provision (Section 63.4 of Module D) related to the designation of NCAs is focused only on chronic congestion that creates sustained local market power. However, transitory conditions (transmission or generation outages) can arise that create a severely-constrained area where the market is vulnerable to the exercise of substantial local market power. Although these areas would not satisfy the criteria to be defined as permanent NCAs, we had concluded that under these transitory conditions, the Tariff provisions were insufficient to effectively address the resulting local market power. Hence, we recommended that MISO expand Module D mitigation provisions to allow temporary "dynamic" NCAs to be defined while the conditions persist and employ a fixed conduct and impact threshold of $25 per MWh.

Status and Resolution: MISO filed the tariff changes to address this recommendation in 2017, which were approved and became effective January 4, 2018. It will improve the effectiveness of the mitigation measures at addressing market power caused by transitory conditions (transmission or generation outages) that create severely-constrained areas.

Unresolved Recommendations Not Included in 2017 Report

2015-3: Model VLR requirements in the Day-Ahead market.

Most of the VLR requirements in MISO South are satisfied through commitments made prior to the day-ahead market. In 2015 and 2016, MISO has continued to improve the day-ahead VLR commitment process and related RSG costs have declined sharply.

Status: While we may revisit this recommendation in the future to improve commitment of units with long start times, current results do not warrant prioritizing this recommendation. We will revisit this recommendation in the future if warranted by market results. In addition, this recommendation will be overtaken by the separate recommendation on modeling the regional 30-minute reserve requirements (See 2014-2).

2015-7: Improve the physical withholding mitigation measures for the PRA by addressing uneconomic retirements.

As capacity margins fall in MISO, the market will become more vulnerable to physical withholding. However, the MISO tariff is not fully effective in mitigating clear exercises of market power in the PRA through physical withholding. In particular, it is not clear that retiring a unit that is clearly economic to continue operating would be considered physical withholding and subject to MISO's mitigation measures.

Therefore, we had recommended that MISO improve the physical withholding mitigation measures for the PRA by clarifying how they would be applied to uneconomic retirements.

Status: MISO has not expressed support for addressing uneconomic retirements. This recommendation is not aligned with the MISO Roadmap and MISO indicates it is inactive. The current surplus in MISO has limited the vulnerability of the MISO market to this form of physical withholding. Given MISO's lack of support for this recommendation, we are suspending the recommendation for now.

2015-8: Improve the limit on the transfer constraint between MISO South and Midwest in the PRA.

MISO models a regional transfer constraint between the MISO South and Midwest regions in the PRA that is intended to represent the amount of capacity located in MISO South that can be relied upon to address contingencies in MISO Midwest and vice versa. Early in 2016, MISO entered into a settlement agreement whereby MISO has the authority to schedule transfers up to 3,000 MW from MISO Midwest to South and 2,500 MW from MISO South to Midwest. However, MISO neighbors may declare an emergency and request that MISO temporarily reduce its interregional transfers to a lower level. This should rarely occur, because MISO may coordinate the flows on individual constraints that are affected by its transfers through its Market-to-Market coordination (with SPP and PJM) or through the TLR process (with other control area operators). Nonetheless, these caps on the transfers do not represent firm transfer capabilities.

For the most recent PRA, MISO enforced a MISO South to Midwest transfer limit of 1,500 MW. It calculated this value by starting with the full transfer limit and subtracting firm transmission rights that source in MISO South and sink in external areas that are interconnect with MISO Midwest. In other words, it assumed that participants that hold firm external transmission rights (e.g., from a MISO South location to PJM) can occupy the transfer constraint.[43] This approach is not reasonable because holders of firm transmission rights cannot prevent MISO from transferring power over the transfer interface between the regions. These participants simply have the authority to schedule a firm export, which MISO will support with its dispatch – the real-time dispatch will determine which generation will ramp up to support the export.

Hence, we recommend that the transfer limit assumed in the PRA equal the total transfer limit minus a derating factor that represents the probability that MISO neighbors will request a derating. If this probability is deemed to be five percent, then the south-to-north transfer limit would equal 2375 MW (2500 MW * 0.95). This recommendation would have had a substantial effect on the clearing prices in most of the Midwest zones in the PRA for the 2016/2017 planning year.

<u>Status:</u> MISO filed to codify their current methodology, which does not address this recommendation. We filed a protest on this methodology because it is inconsistent with MISO's system operations. On November 16, 2017, FERC accepted MISO's compliance filing subject to certain conditions. MISO's methodology for calculating the transfer limit is now part of the Tariff and was found to be just and reasonable by FERC. Therefore, although MISO's methodology is unsound, we are suspending this recommendation for this Report.

43 In a similar fashion, MISO established a 2,794 MW transfer limit from MISO Midwest to MISO South, but it did not bind in the most recent PRA.

2010-11: Include expected deployment costs when selecting spinning reserves.

The MISO operating reserve market does not consider resources' potential deployment costs when it procures reserves. This caused MISO to routinely schedule spinning reserves on resources that were very expensive to deploy, resulting in millions of dollars of inefficient guarantee payments when they were deployed. Including the expected value of these costs in the procurement process would have resulted in more efficient reserve scheduling. Hence, we recommended that MISO address this issue in one of two ways, either by:

- Eliminating the guarantee payment made to spinning reserve providers when they are deployed; or
- Calculating the expected value of the out-of-market deployment cost for each unit, and adding that expected cost to each unit's spinning reserve offer.

Status: This recommendation was originally made in the *2010 State of the Market Report.* In June 2016, the IMM and MISO staff presented these alternatives to the MISO Market Subcommittee. The first alternative would compel the resource owner to include the expected deployment cost in its offer so these costs would be included in the selection and pricing of spinning reserves. The second alternative would explicitly incorporate the expected deployment costs (as estimated by MISO) in the selection and pricing of spinning reserves. The IMM and MISO staff did an additional analysis in 2016 and found that because certain units are no longer participating in the market, the impact of this issue has declined significantly.

2014-1: Modify the allocation of FTR shortfalls in order to fully fund MISO's FTRs.

Currently, all funding shortfalls are allocated to the FTR holders, which can result in funding that is less than 100 percent. This diminishes the value of the FTRs as congestion hedges and lowers their prices. To the extent that the shortfall levels are uncertain, the prices for the FTRs are likely to fall by more than the shortfall amount. Ultimately, this harms MISO's transmission customers by reducing the allocation of FTR revenues to the transmission customers.

Therefore, we recommended that MISO guarantee full funding of its FTRs by allocating the shortfall directly to transmission customers. Customers would receive higher FTR revenues as the prices for the FTRs rise, which should more than offset this allocation. We also recommended that some or all of the shortfalls that are due to transmission outages should be allocated to the transmission owners to improve their incentives to schedule outages more efficiently (i.e., to limit their duration and take the outages in periods that are least likely to cause significant congestion costs).

Status: MISO's initial assessment was that this recommendation could improve economic incentives for scheduling outages, but that modifying the allocation of FTR shortfalls is not a high priority at this time because funding levels are relatively high. Given MISO's assessment, we are suspending this recommendation and will reconsider it in the future.